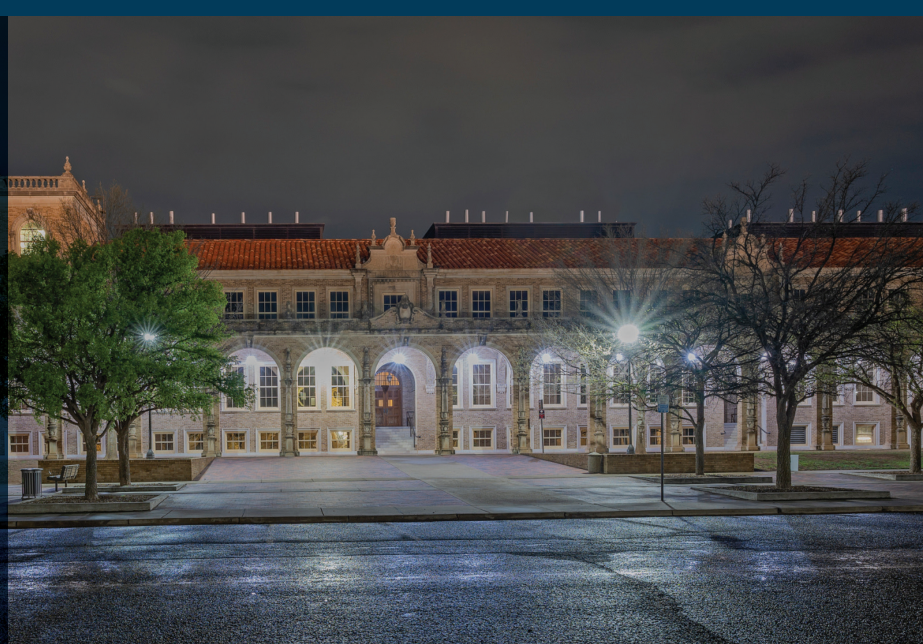
2024

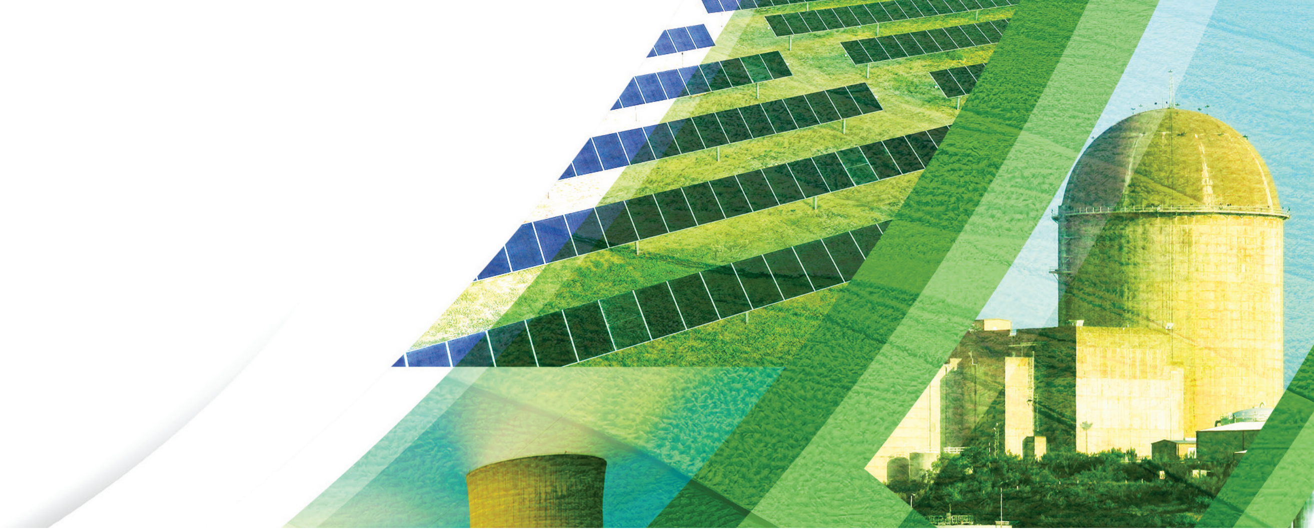
ANNUAL REPORT

As Lubbock's electricity market opened to competition in 2024, TXU Energy quickly became the city's top choice for homes and businesses. With the power to switch from the local utility to an electricity provider of their choice, tens of thousands of people turned to TXU Energy for straightforward, affordable electricity plans – more than any other provider.

This shift reflects a growing trend across the U.S., where more cities and regions are exploring the benefits of electricity market competition in a retail electric market, giving consumers the ability to choose the provider that best fits their needs and usage habits.

In Lubbock, TXU Energy is proud to serve as the energy provider for Texas Tech University, Lubbock's largest employer. This multi-year partnership is tailored to meet the needs of the university's 40,000+ students, featuring scholarship investments and significant energy efficiency rebates.





Dear Fellow Vistra Stockholders:

Jim Burke
President & Chief Executive Officer

For Vistra, 2024 was defined by growth, transformation, and success driven by a One Team mindset. We carried out our purpose, "Lighting Up Lives, Powering a Better Way Forward," through our four strategic priorities. These continue to guide our strategic decisions and position Vistra for current and future success.

We started the year strong with the successful close of the Energy Harbor acquisition on March 1. Our team hit the ground running, successfully integrating the operations and delivering synergies exceeding initial expectations. This transformative acquisition grew our Vistra Vision zero-carbon generation and retail electricity business, adding approximately 4,000 megawatts of 24/7 nuclear generation and approximately 1 million retail customers. Our company now owns and operates the second-largest competitive nuclear fleet in the country.

Our integrated business model delivered another year of strong results throughout a variety of pricing and weather conditions. We concluded the year with $5.656 billion of Ongoing Operations Adjusted EBITDA[1], which was $856 million dollars higher than the midpoint of the original guidance range announced in May 2024. We also achieved $2.888 billion of Ongoing Operations Adjusted Free Cash Flow Before Growth[1], exceeding the midpoint of the original guidance set by $438 million.

1) Non-GAAP financial measure. See the "Non-GAAP Reconciliation" tables for further details.

2024 marked **new expectations** for forecasted power demand.

We remain committed to **creating value** for our shareholders.

We were encouraged to see the strength of our business and its improving growth profile recognized with our company's inclusion in the S&P 500 index in May 2024. Over the summer, we announced two power purchase agreements for solar energy with two of the world's leading tech companies, totaling over 600 MW — one for 200 MW with Amazon in Texas and another for 405 MW with Microsoft in Illinois. In the fourth quarter, we completed and brought online two new solar-plus-storage projects in Illinois, both on the sites of retired or to-be-retired coal plants, transforming the sites into renewable energy centers and producing needed generation for the MISO region.

We remain committed to creating value for our shareholders through disciplined capital allocation. Our long-term capital allocation program has generated significant value to shareholders since its inception in November 2021.

Through Feb. 24, 2025, we executed approximately $4.9 billion of share repurchases. This program reduced Vistra's share count by ~30% from November 2021, while the consistent allocation of $300 million in dividends per year resulted in our dividend per share increasing ~48% since November 2021. On Oct. 30, 2024, our Board authorized an additional $1 billion for share repurchases expected to be utilized through 2026. As we reduce the share count each quarter, we plan for the dividend per share to continue to grow.

The year also marked new expectations for forecasted power demand with growth rates the industry hasn't seen since the 1960s, when electrification was in full swing. Multiple avenues are driving demand growth across the markets we serve, including potential buildout of data centers, continued reshoring of industrial activities as evidenced by multiple large chip manufacturing site buildouts, increased electrification of commercial, industrial, and residential load across the country, strong population growth, and electrification of the Permian Basin in Texas/ERCOT.

Vistra's diverse asset base is well-positioned to navigate these industry trends while continuing to provide reliable power for our customers. Our team is acutely focused on strategically positioning Vistra for success in this new supply/demand environment.

Long-term, Sustainable Value Creation through the Integrated Business Model

The combination of Vistra's diverse fleet of generation assets, growing retail business, and comprehensive hedging program forms an integrated platform that delivers attractive earnings and enables the return of significant capital to shareholders while allowing for continued investment to keep our fleet and our customer value proposition in a strong competitive position. Our integrated operations are the cornerstone of our company, and we remain confident that our best-in-class, efficient, low-cost generation fleet paired with a stable, customer-centric retail business will continue to drive Vistra forward well into the future.

RETAIL

Vistra's retail team provided strong Ongoing Operations Adjusted EBITDA this year, increasing the ongoing run-rate we expect while providing best-in-class service our customers can trust. Our retail team outperformed expectations in 2024, and we expect this trend to continue into the foreseeable planning horizon. Our retail team introduced new and creative campaigns while continuing to increase counts across the markets we serve. Our flagship retail brand, TXU Energy, held a 5-star rating by the Public Utility Commission of Texas for 27 straight months, showcasing our passion for excellence. We also saw our fourth consecutive year of organic growth in ERCOT, increasing residential customer counts year-over-year. Adding to an excellent year for retail was the sales performance of our large business markets team, which ended the year well ahead of expectations.

GENERATION

This year brought volatile commodity and weather conditions. Our generation team's unparalleled drive for results was showcased by achieving 95%[2] commercial availability fleetwide and 92%[3] for our nuclear fleet in 2024. Safety remained our highest priority, with 14 of our plants recognized with OSHA VPP Star rating. This designation is reserved for exemplary worksites with comprehensive, successful safety and health management systems; currently, less than 1% of eligible sites in the country hold this recognition.

2) Commercial availability defined as measure of the ability of the fossil fleets in the Texas, East, and West segments to meet demand during the highest margin hours.
3) Based on full-year operating performance for the PJM nuclear assets.

"Our best-in-class commercial and generation teams partnered to optimize the fleet and worked together to provide the financial results we set out to achieve."

Our retail team **outperformed** growth expectations in 2024.

Our generation team achieved **95% commercial availability** fleet-wide for the year.

The year also brought volatile weather environments. Winter Storm Heather occurred in January followed by mild winter weather in February and March, and our power plants remained flexible during daily operations and rescheduled planned outages to optimize opportunities when available. In summer, despite mild weather in Texas and lower wholesale prices across competitive markets, the generation team capitalized on the volatility by optimizing the run profile of our generation units and coordinating with our commercial teams to maximize value from our hedges. Overall, the diverse conditions allowed Vistra to demonstrate our high-performance culture, delivering for our customers and our shareholders.

Conclusion

Our goal at Vistra is to be an industry leader in the power space by combining a "vision" for success with a "tradition" of excellence. We will continue to deliver value to our customers, communities, shareholders, and our people — now and in the future. Vistra is positioned for success, and we are extremely proud of our team's tremendous 2024 performance. Vistra is a key player in this dynamic energy transformation underway across the U.S. and opportunities are very exciting for our stakeholders. We appreciate you, our investors, for trusting us and supporting our purpose.

Thank you for your continued interest in Vistra; we look forward to the year ahead.

Jim Burke
President & Chief Executive Officer

Non-GAAP Financial Measures and Forward-Looking Statements. This letter includes references to Ongoing Operations Adjusted EBITDA and Ongoing Operations Adjusted Free Cash Flow before Growth which are non-GAAP financial measures. For reconciliations between our non-GAAP measures and the nearest GAAP measures, please refer to the tables that follow. As non-GAAP financial measures are not intended to be considered in isolation or as a substitute for GAAP financial measures, you should carefully read the Form 10-K included in this Annual Report, which includes our consolidated financial statements prepared in accordance with GAAP. Additionally, this letter includes statements that, to the extent they are not recitations of historical fact, constitute forward-looking statements within the meaning of the federal securities laws, and are based on Vistra's current expectations and assumptions. For a discussion identifying important factors that could cause actual results to vary materially from those anticipated in the forward-looking statements, see Vistra's filings with the Securities and Exchange Commission including, but not limited to, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Risk Factors" in the Form 10-K portion of this Annual Report.

Non-GAAP Reconciliations - 2024 Adjusted EBITDA

Twelve Months Ended December 31, 2024 (Unaudited, Millions of Dollars)

	Retail	Texas	East	West	Eliminations / Corp and Other	Ongoing Operations Consolidated	Asset Closure	Vistra Corp. Consolidated
Net income (loss)	**$1,216**	**$2,133**	**$902**	**$471**	**$(1,794)**	**$2,928**	**$(116)**	**$2,812**
Income tax expense	0	0	0	0	655	655	0	655
Interest expense and related charges (a)	54	(46)	(9)	(1)	898	896	4	900
Depreciation and amortization (b)	114	686	1,278	86	66	2,230	0	2,230
EBITDA before Adjustments	**1,384**	**2,773**	**2,171**	**556**	**(175)**	**6,709**	**(112)**	**6,597**
Unrealized net (gain) loss resulting from hedging transactions	52	(790)	(76)	(332)	0	(1,146)	(9)	(1,155)
Purchase accounting impacts	0	1	(12)	0	(14)	(25)	0	(25)
Impacts of Tax Receivable Agreement (c)	0	0	0	0	(5)	(5)	0	(5)
Non-cash compensation expenses	0	0	0	0	100	100	0	100
Transition and merger expenses	2	1	22	0	111	136	0	136
Decommissioning-related activities (d)	0	26	(91)	2	0	(63)	0	(63)
ERP system implementation expenses	8	7	5	1	0	21	2	23
Other, net	17	14	(2)	11	(111)	(71)	2	(69)
Adjusted EBITDA	**$1,463**	**$2,032**	**$2,017**	**$238**	**$(94)**	**$5,656**	**$(117)**	**$5,539**

Note: Texas and East segments include nuclear PTC revenue estimate of $281 million and $264 million, respectively. See Note 4 to the Financial Statements for additional information.
(a) Includes $53 million of unrealized mark-to-market net losses on interest rate swaps.
(b) Includes nuclear fuel amortization of $105 million and $282 million, respectively, in Texas and East segments.
(c) Includes $10 million gain recognized on the repurchase of TRA Rights in the Twelve Months ended December 31, 2024.
(d) Represents net of all NDT (income) loss of the PJM nuclear facilities, ARO accretion expense for operating assets and ARO remeasurement impacts for operating assets.

Non-GAAP Reconciliations – 2024 Adjusted Free Cash Flow Before Growth

Twelve Months Ended December 31, 2024 (Unaudited, Millions of Dollars)

	Ongoing Operations	Asset Closure	Vistra Consolidated
Adjusted EBITDA	**$5,656**	**$(117)**	**$5,539**
Interest paid, net (a)	(939)	0	(939)
Taxes paid	(56)	0	(56)
Change in working capital, margin deposits, and accrued environmental allowance obligations	1,048	0	1,048
Reclamation and remediation expenditures	(39)	(49)	(88)
ERP implementation expenditures	(53)	0	(53)
Transition and merger expenditures	(155)	(1)	(156)
Other changes in other operating assets and liabilities	(757)	25	(732)
Cash provided by (used in) operating activities	**4,705**	**(142)**	**4,563**
Capital expenditures for maintenance including net nuclear fuel purchases and LTSA prepayments (b)	(1,092)	0	(1,092)
Proceeds from sale of transferable investment tax credits	150	0	150
Change in working capital, margin deposits, and accrued environmental allowance obligations	(1,048)	0	(1,048)
Transition and merger expenditures	155	1	156
ERP implementation expenditures	53	0	53
Other net investing activities (c)	(35)	0	(35)
Adjusted FCFbG	**$2,888**	**$(141)**	**$2,747**

(a) Net of interest received.
(b) Excludes $800 million of capital expenditures related to growth and development.
(c) Includes net contributions to nuclear decommissioning trusts and other.

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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

— OR —

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __ to __

Commission File Number 001-38086

Vistra Corp.

(Exact name of registrant as specified in its charter)

Delaware	**36-4833255**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
6555 Sierra Drive Irving, Texas 75039	**(214) 812-4600**
(Address of principal executive offices) (Zip Code)	(Registrant's telephone number, including area code)

	Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Securities registered pursuant to Section 12(b) of the Act:	Common stock, par value $0.01 per share	VST	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 ☐

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

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

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

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 Exchange Act). Yes ☐ No ☒

As of June 30, 2024, the last business day of Vistra Corp.'s most recently completed second fiscal quarter, the aggregate market value of the Vistra Corp. common stock held by non-affiliates of the registrant was $29,500,179,937 based on the closing sale price as reported on the New York Stock Exchange.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Class	Outstanding as of February 24, 2025
Common stock, par value $0.01 per share	338,963,642

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive Proxy Statement relating to its 2025 Annual Meeting of Stockholders are incorporated by reference in Part III of this annual report on Form 10-K.

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GLOSSARY OF TERMS AND ABBREVIATIONS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Current and Former Related Entities:

Ambit	Ambit Holdings, LLC, and/or its subsidiaries (d/b/a Ambit), depending on context
BCOP	BCOP Borrower LLC, a subsidiary of Vistra Zero
Crius	Crius Energy Trust and/or its subsidiaries, depending on context
Dynegy	Dynegy Inc., and/or its subsidiaries, depending on context
Dynegy Energy Services	Dynegy Energy Services, LLC and Dynegy Energy Services (East), LLC (each d/b/a Dynegy, Better Buy Energy, Brighten Energy, Honor Energy and True Fit Energy), indirect, wholly owned subsidiaries of Vistra, that are REPs in certain areas of MISO and PJM, respectively, and are engaged in the retail sale of electricity to residential and business customers
EFH Corp.	Energy Future Holdings Corp., a holding company and formerly the indirect parent of our predecessor
Energy Harbor	Energy Harbor Holdings LLC (formerly known as Energy Harbor Corp.), and/or its subsidiaries, depending on context
Homefield Energy	Illinois Power Marketing Company (d/b/a Homefield Energy), an indirect, wholly owned subsidiary of Vistra, a REP in certain areas of MISO that is engaged in the retail sale of electricity to municipal customers
Luminant	subsidiaries of Vistra engaged in competitive market activities consisting of electricity generation and wholesale energy sales and purchases as well as commodity risk management
Oncor	Oncor Electric Delivery Company LLC, a direct, majority-owned subsidiary of Oncor Holdings and formerly an indirect subsidiary of EFH Corp., that is engaged in regulated electricity transmission and distribution activities
Parent	Vistra Corp.
Public Power	Public Power, LLC (d/b/a Public Power), an indirect, wholly owned subsidiary of Vistra, a REP in certain areas of PJM, ISO-NE, NYISO and MISO that is engaged in the retail sale of electricity to residential and business customers
TCEH	Texas Competitive Electric Holdings Company LLC, a direct, wholly owned subsidiary of Energy Future Competitive Holdings Company LLC, and, prior to the Effective Date, the parent company of our predecessor, depending on context, that were engaged in electricity generation and wholesale and retail energy market activities, and whose major subsidiaries included Luminant and TXU Energy
TriEagle Energy	TriEagle Energy, LP (d/b/a TriEagle Energy, TriEagle Energy Services, Eagle Energy, Energy Rewards, Power House Energy and Viridian Energy), an indirect, wholly owned subsidiary of Vistra, a REP in certain areas of ERCOT and PJM that is engaged in the retail sale of electricity to residential and business customers
TXU Energy	TXU Energy Retail Company LLC (d/b/a TXU), an indirect, wholly owned subsidiary of Vistra that is a REP in competitive areas of ERCOT and is engaged in the retail sale of electricity to residential and business customers
U.S. Gas & Electric	U.S. Gas and Electric, LLC (d/b/a USG&E, Illinois Gas & Electric and ILG&E), an indirect, wholly owned subsidiary of Vistra, a REP in certain areas of PJM, ISO-NE, NYISO and MISO that is engaged in the retail sale of electricity to residential and business customers
Value Based Brands	Value Based Brands LLC (d/b/a 4Change Energy, Express Energy and Veteran Energy), an indirect, wholly owned subsidiary of Vistra that is a REP in competitive areas of ERCOT and is engaged in the retail sale of electricity to residential and business customers
Vistra	Vistra Corp., and/or its subsidiaries, depending on context
Vistra Intermediate	Vistra Intermediate Company LLC, a direct, wholly owned subsidiary of Vistra
Vistra Operations	Vistra Operations Company LLC, an indirect, wholly owned subsidiary of Vistra that is the issuer of certain series of notes (see Note 9 to the Financial Statements) and borrower under the Vistra Operations Credit Facilities
Vistra Vision	Vistra Vision LLC, an indirect, wholly owned subsidiary of Vistra
Vistra Zero	subsidiaries of Vistra engaged in the operation and development of renewables and energy storage assets resulting in continued modernization of our generation fleet.
Vistra Zero Operations	Vistra Zero Operating Company, LLC, an indirect, wholly owned subsidiary of Vistra

Transmission System Operators:

CAISO	The California Independent System Operator
ERCOT	Electric Reliability Council of Texas, Inc.
ISO-NE	ISO New England Inc.
MISO	Midcontinent Independent System Operator, Inc.
NYISO	New York Independent System Operator, Inc.
PJM	PJM Interconnection, LLC

Authoritative Organizations:

CFTC	U.S. Commodity Futures Trading Commission
EPA	U.S. Environmental Protection Agency
FERC	U.S. Federal Energy Regulatory Commission
FTC	Federal Trade Commission
IEPA	Illinois Environmental Protection Agency
IPCB	Illinois Pollution Control Board
IRS	U.S. Internal Revenue Service
MSHA	U.S. Mine Safety and Health Administration
NERC	North American Electric Reliability Corporation
NRC	U.S. Nuclear Regulatory Commission
PUCT	Public Utility Commission of Texas
RCT	Railroad Commission of Texas, which among other things, has oversight of lignite mining activity in Texas, and has jurisdiction over oil and natural gas exploration and production, permitting and inspecting intrastate pipelines, and overseeing natural gas utility rates and compliance
SEC	U.S. Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality
TRE	Texas Reliability Entity, Inc., an independent organization that develops reliability standards for the ERCOT region and monitors and enforces compliance with NERC standards and monitors compliance with ERCOT protocols

Rules and Regulations:

CAA	Clean Air Act
ERISA	Employee Retirement Income Security Act of 1974
Exchange Act	Securities Exchange Act of 1934, as amended
IRA	Inflation Reduction Act of 2022
Securities Act	Securities Act of 1933, as amended

General Terms:

2023 Form 10-K	Vistra's annual report on Form 10-K for the year ended December 31, 2023, filed with the SEC on February 29, 2024
Ambit Transaction	the acquisition of Ambit by an indirect, wholly owned subsidiary of Vistra on November 1, 2019 (Ambit Acquisition Date)
ARO	asset retirement and mining reclamation obligation
BCOP Credit Agreement	credit agreement, dated as of December 16, 2024 (as amended, restated, amended and restated, supplemented and/or otherwise modified from time to time), by and among BCOP, the lenders and issuing banks party thereto, the administrative agent, and collateral agent and the other parties named therein
CCGT	combined cycle natural gas turbine
CCR	coal combustion residuals
CME	Chicago Mercantile Exchange
CO_2	carbon dioxide

Crius Transaction	the acquisition of equity interests of two wholly owned subsidiaries of Crius that indirectly owned the operating business of Crius by an indirect, wholly owned subsidiary of Vistra on July 15, 2019 (Crius Acquisition Date)
CT	combustion turbine
Dynegy Merger	the merger of Dynegy with and into Vistra, with Vistra as the surviving corporation, on April 9, 2018, the date Vistra and Dynegy completed the transactions contemplated by the Agreement and Plan of Merger, dated as of October 29, 2017, by and between Vistra and Dynegy (Dynegy Merger Date)
EBITDA	earnings (net income) before interest expense, income taxes, depreciation and amortization
Effective Date	October 3, 2016, the date our predecessor completed its reorganization under Chapter 11 of the U.S. Bankruptcy Code
ESG	environmental, social and governance
ESS	energy storage system
Fitch	Fitch Ratings Inc. (a credit rating agency)
GAAP	generally accepted accounting principles
GHG	greenhouse gas
GWh	gigawatt-hours
Green Finance Framework	Framework adopted by the Company and made available on its website pursuant to which the Company may issue financial instruments to fund new or existing projects that support renewable energy and energy efficiency, with alignment to the Company's environmental, social, and governance strategy
Heat Rate	Heat Rate is a measure of the efficiency of converting a fuel source to electricity
ISO	independent system operator
ITC	investment tax credit
kW	kilowatt
LIBOR	London Interbank Offered Rate, an interest rate at which banks can borrow funds, in marketable size, from other banks in the London interbank market
load	demand for electricity
LTSA	long-term service agreements for plant maintenance
Market Heat Rate	Market Heat Rate is the implied relationship between wholesale electricity prices and natural gas prices and is calculated by dividing the wholesale market price of electricity, which is based on the price offer of the marginal supplier (generally natural gas plants), by the market price of natural gas.
MMBtu	million British thermal units
Moody's	Moody's Investors Service, Inc. (a credit rating agency)
MW	megawatts
MWh	megawatt-hours
NO_X	nitrogen oxide
NYMEX	the New York Mercantile Exchange, a commodity derivatives exchange
NYSE	New York Stock Exchange
OPEB	postretirement employee benefits other than pensions
PrefCo Preferred Stock Sale	as part of the tax-free spin-off from EFH Corp. executed pursuant to the Third Amended Joint Plan of Reorganization filed by the parent company of our predecessor in August 2016 and confirmed by the U.S. Bankruptcy Court for the District of Delaware in August 2016 solely with respect to our predecessor (Plan of Reorganization) on the Effective Date, the contribution of certain of the assets of the predecessor and its subsidiaries by a subsidiary of TEX Energy LLC to Vistra Preferred Inc. (PrefCo) in exchange for all of PrefCo's authorized preferred stock, consisting of 70,000 shares, par value $0.01 per share
PTC	production tax credit
REP	retail electric provider
RTO	regional transmission organization
S&P	Standard & Poor's Ratings (a credit rating agency)
Series A Preferred Stock	Vistra's 8.0% Series A Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock, $0.01 par value, with a liquidation preference of $1,000 per share

Series B Preferred Stock	Vistra's 7.0% Series B Fixed-Rate Reset Cumulative Green Redeemable Perpetual Preferred Stock, $0.01 par value, with a liquidation preference of $1,000 per share
Series C Preferred Stock	Vistra's 8.875% Series C Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock, $0.01 par value, with a liquidation preference of $1,000 per share
SG&A	selling, general, and administrative
SO_2	sulfur dioxide
SOFR	Secured Overnight Financing Rate, the average rate at which institutions can borrow U.S. dollars overnight while posting U.S. Treasury Bonds as collateral
ST	steam turbine
Tax Matters Agreement	Tax Matters Agreement, dated as of the Effective Date, by and among EFH Corp., Energy Future Intermediate Holding Company LLC, EFIH Finance Inc. and EFH Merger Co. LLC
TRA	Amended and Restated Tax Receivable Agreement, containing certain rights (TRA Rights) to receive payments from Vistra related to certain tax benefits, including benefits realized as a result of certain transactions entered into at the emergence of our predecessor from reorganization under Chapter 11 of the U.S. Bankruptcy Code as subsidiaries of a newly formed company, Vistra, on the Effective Date
TWh	terawatt-hours
U.S.	United States of America
Vistra Operations Commodity-Linked Credit Agreement	credit agreement, dated as of February 4, 2022 (as amended, restated, amended and restated, supplemented, and/or otherwise modified from time to time) by and among Vistra Operations, Vistra Intermediate, the lenders party thereto, the other credit parties thereto, the administrative agent, the collateral agent, and the other parties named therein
Vistra Operations Credit Agreement	credit agreement, dated as of October 3, 2016 (as amended, restated, amended and restated, supplemented and/or otherwise modified from time to time), by and among Vistra Operations, Vistra Intermediate, the lenders party thereto, the letter of credit issuers party thereto, the administrative agent, the collateral agent, and the other parties named therein
Vistra Operations Credit Facilities	Vistra Operations senior secured financing facilities (see Note 9 to the Financial Statements)
Vistra Zero Credit Agreement	credit agreement, dated as of March 26, 2024 (as amended, restated, amended and restated, supplemented and/or otherwise modified from time to time), by and among Vistra Zero Operating Company, LLC, the lenders party thereto, the administrative agent, and collateral agent, and the other parties named therein

FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K contains forward-looking statements that involve risk and uncertainties. All statements, other than statements of historical facts, that are included in this report, or made in presentations, in response to questions or otherwise, that address activities, events or developments that may occur in the future, including (without limitation) such matters as activities related to our financial or operational projections, capital allocation, capital expenditures, liquidity, dividend policy, business strategy, competitive strengths, goals, future acquisitions or dispositions, development or operation of power generation assets, market and industry developments and the growth of our businesses and operations, including potential transactions with large load facilities at our nuclear and natural gas plants (often, but not always, through the use of words or phrases such as "intends," "plans," "potential," "will likely," "unlikely," "believe," "expect," "anticipated," "estimate," "should," "could," "may," "projection," "forecast," "target," "goal," "objective," and "outlook"), are forward-looking statements. Although we believe that in making any such forward-looking statement our expectations are based on reasonable assumptions, any such forward-looking statement involves uncertainties and risks and is qualified in its entirety by reference to the discussion in Item 1A. *Risk Factors* and Item 7. *Management's Discussion and Analysis of Financial Condition, and Results of Operations* in this annual report on Form 10-K.

Any forward-looking statement speaks only at the date on which it is made, and except as may be required by law, we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of unanticipated events or circumstances. New factors emerge from time to time, and it is not possible for us to predict them. In addition, we may be unable to assess the impact of any such event or condition or the extent to which any such event or condition, or combination of events or conditions, may cause results to differ materially from those contained in or implied by any forward-looking statement. As such, you should not unduly rely on such forward-looking statements.

INDUSTRY AND MARKET INFORMATION

Certain industry and market data and other statistical information used throughout this report are based on independent industry publications, government publications, reports by market research firms or other published independent sources, including certain data published by CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, the environmental regulatory bodies of states in which we operate, and NYMEX. We did not commission any of these publications, reports or other sources. Some data is also based on good faith estimates, which are derived from our review of internal surveys, as well as the independent sources listed above. Industry publications, reports, and other sources generally state that they have obtained information from sources believed to be reliable, but do not guarantee the accuracy and completeness of such information. While we believe that each of these studies, publications, reports, and other sources is reliable, we have not independently investigated or verified the information contained or referred to therein and make no representation as to the accuracy or completeness of such information. Forecasts are particularly likely to be inaccurate, especially over long periods of time, and we do not know what assumptions were used in preparing such forecasts. Statements regarding industry and market data and other statistical information used throughout this report involve risks and uncertainties and are subject to change based on various factors.

PART I

Item 1. BUSINESS

References in this report to "we," "our," "us," and "the Company" are to Vistra and/or its subsidiaries, as apparent in the context. See *Glossary of Terms and Abbreviations* for defined terms.

General

Vistra is an integrated retail electricity and power generation company. We combine an innovative, customer-centric approach to retail sales with safe, reliable, diverse, and efficient power generation. Our integrated power generation and wholesale operation allows us to efficiently obtain the electricity needed to serve our customers at the lowest cost. The integrated model enables us to structure products and contracts in a way that offers significant value compared to stand-alone retail electric providers.

The Company brings its products and services to market in 18 states and the District of Columbia, including all major competitive wholesale power markets in the U.S. We serve approximately 5 million residential, commercial, and industrial retail customers with electricity and natural gas. Our generation fleet totals approximately 41,000 megawatts of generation capacity powered by a diverse portfolio, including natural gas, nuclear, coal, solar, and battery energy storage facilities.

Market Discussion

The operations of Vistra, as an integrated retail electricity and power generation company, are further aligned into five reportable business segments: (i) Retail, (ii) Texas, (iii) East, (iv) West, and (v) Asset Closure. Our Texas, East, and West segments include our electricity generation operations, and our Asset Closure segment is engaged in the decommissioning and reclamation of retired plants and mines. In the fourth quarter of 2024, we updated our reportable segments to reflect changes in how the Company's Chief Operating Decision Maker (CODM) makes operating decisions, assesses performance, and allocates resources by eliminating the Sunset segment. The results of the plants previously included in the Sunset segment are now reflected in the Texas and East segments based on their respective geography.

Retail Operations

Vistra is one of the largest competitive residential retail electricity providers in the U.S. Our retail operations are engaged in retail sales of electricity, natural gas, and related services to approximately 5 million customers. Substantially all of our retail activities are conducted by TXU Energy, Ambit Energy, Dynegy Energy Services, Homefield Energy, and U.S. Gas & Electric across 16 U.S. states and the District of Columbia. The largest portion of our retail operations are in Texas, where we provide retail electricity to approximately 2.6 million customers.

Our TXU Energy brand, which has been used to sell electricity to customers in the competitive retail electricity market in Texas for over 20 years, is registered and protected by trademark law. We also own the trade names for Ambit Energy, Dynegy Energy Services, Homefield Energy, TriEagle Energy, Public Power, and U.S. Gas & Electric.

We believe that we have differentiated ourselves by providing a distinctive customer experience predicated on delivering reliable and innovative power products and solutions to our customers, including 100% wind and solar options, as well as thermostats, dashboards, and other programs designed to encourage reduced electricity consumption and increased energy efficiency. Our distinctive power products give our customers choice, convenience, and control over how and when they use electricity and related services.

Electricity Generation Operations

Vistra is the largest competitive power generator in the U.S. as measured by MWh of generation capacity. At December 31, 2024, our generating capacity was powered by the following:

Primary Fuel	Technology	Net Capacity (MW)	% of Net Capacity
Natural Gas	CCGT, CT or ST	24,120	59%
Coal	ST	8,428	21%
Uranium	Nuclear	6,448	16%
Renewable	Solar/Battery	1,474	4%
Fuel Oil	CT	187	—%
Total		40,657	100%

Our natural gas-fueled generation fleet is comprised of 23 CCGT generation facilities totaling 19,742 MW and 10 peaking generation facilities totaling 4,378 MW. We satisfy our fuel requirements at these facilities through a combination of spot market and near-term purchase contracts. Additionally, we have near-term natural gas transportation agreements and natural gas storage agreements in place to ensure fleet reliability.

Our coal/lignite-fueled generation fleet is comprised of seven generation facilities totaling 8,428 MW of generation capacity. We meet our fuel requirements at our coal-fueled generation facilities in PJM and MISO with coal purchased from multiple suppliers under contracts of various lengths and transported to the facilities by either railcar or barges. We meet our fuel requirements in ERCOT using lignite that we mine at our generation facilities and coal purchased and transported by railcar.

We own and operate six nuclear generation units at four different facilities:

Unit	ISO	Net Capacity (MW)	Refueling Outage Frequency	License Expiration Date
Comanche Peak Unit 1	ERCOT	1,200	18 Months	2050
Comanche Peak Unit 2	ERCOT	1,200	18 Months	2053
Beaver Valley Unit 1	PJM	939	18 Months	2036
Beaver Valley Unit 2	PJM	933	18 Months	2047
Perry	PJM	1,268	24 Months	2026 (a)
Davis-Besse	PJM	908	24 Months	2037
Total		6,448		

(a) In 2023, an application for a license renewal at our Perry nuclear plant was filed with the NRC to extend our license through 2046.

Nuclear units are generally operated at full capacity. Refueling (nuclear fuel assembly replacement) outages for each unit are scheduled to occur during the spring or fall off-peak demand periods. While one unit is undergoing a refueling outage at dual-unit facilities, the remaining unit is intended to operate at full capacity. During a refueling outage, other maintenance, modification, and testing activities are completed that cannot be accomplished when the unit is in operation.

We have contracts in place for all of our nuclear fuel requirements through 2029. We do not anticipate any significant difficulties in acquiring uranium and contracting for associated conversion, enrichment, and fabrication services in the foreseeable future. We continue to monitor developments regarding the availability of nuclear fuel that may arise out of the Russia and Ukraine conflict. See Item 7. *Management's Discussion and Analysis of Financial Condition, and Results of Operations – Significant Activities and Events, and Items Influencing Future Performance – Macroeconomic Conditions*.

Our generation operations by segment are represented in the following table:

Segment	Net Capacity (MW)	% of Net Capacity	ISO/RTO
Texas	19,031	47%	ERCOT
East	19,746	49%	PJM, ISO-NE, MISO, and NYISO
West	1,880	4%	CAISO
Total	40,657	100%	

Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) — ISOs and RTOs manage the transmission infrastructure and markets across regions, separate from our operations. They dispatch generation facilities, ensuring efficient and reliable transmission system operation. ISOs/RTOs administer short-term energy and ancillary service markets, typically day-ahead and real-time, and some also manage long-term planning reserves through various capacity markets. They impose bid and price limits in wholesale power markets. NERC regions and ISOs/RTOs often have different geographic footprints, and while there may be geographic overlap between NERC regions and ISOs/RTOs, their respective roles and responsibilities do not generally overlap.

In centrally dispatched market structures (e.g., ERCOT, PJM, ISO-NE, NYISO, MISO, CAISO), all generators receive the same price for energy based on the bid price of the last MWh needed to balance supply and demand. Prices vary within different zones due to transmission losses and congestion. For example, if a less efficient natural gas unit is needed to meet demand, its offer price sets the market clearing price for all dispatched generation in that market, regardless of other units' offer prices. Generators receive the location-based marginal price for their output.

ERCOT — ERCOT is an ISO that manages the flow of electricity from approximately 103,600 MW of expected Summer 2024 peak generation capacity to approximately 27 million Texas customers, representing approximately 90% of the state's electric load.

As an energy-only market, ERCOT's market design is distinct from other competitive electricity markets in the U.S. Other markets maintain a minimum planning reserve margin through regulated planning, resource adequacy requirements and/or capacity markets. In contrast, ERCOT's resource adequacy is currently predominately dependent on energy-market price signals. The Texas Legislature mandated the development of an ancillary service, the Dispatchable Reliability Reserve Service (DRRS), to address intra-hour operations challenges. The PUCT voted in December 2024 to have ERCOT develop DRRS so it can address both operational issues and resource adequacy issues. ERCOT is continuing work on DRRS, and it has not been implemented as of the date hereof. In 2014, ERCOT implemented the Operating Reserve Demand Curve (ORDC), pursuant to which wholesale electricity prices in the real-time electricity market increase automatically as available operating reserves decrease below defined threshold levels, creating a price adder. The slope of the ORDC curve is determined through a mathematical loss of load probability calculation using forecasted reserves and historical data. In both March 2019 and March 2020, ERCOT implemented 0.25 standard deviation shifts in the loss of load probability calculation and moved to using a single blended ORDC curve; these changes resulted in a more rapid escalation in power prices as operating reserves fall below defined thresholds. Effective January 1, 2022, when operating reserves drop to 3,000 MW or less, the ORDC automatically adjusts power prices to $5,000/MWh which is equal to the high system-wide offer cap. When ERCOT implements real-time co-optimization, discussed below, the ORDC will be replaced by ancillary service demand curves that are designed to mimic the operation of the ORDC. ERCOT also calculates the "peaker net margin" based on revenues a hypothetical unhedged peaking unit would collect in the market. If the peaker net margin exceeds a certain threshold, the system-wide offer cap is reduced to the low system-wide offer cap of $2,000/MWh for the remainder of the calendar year. In December 2023, the PUCT also approved an Emergency Pricing Program that temporarily lowers the system-wide offer cap to $2,000/MWh if prices have been at the cap for 12 hours in a rolling 24-hour period. Historically, high demand due to elevated temperatures in the summer months or high demand due to reduced temperatures in the winter months, combined with underperformance of wind generation, has created the conditions during which the ORDC contributes meaningfully to power prices. Extreme weather conditions can also lead to scarcity conditions regardless of season. Other than during periods of "scarcity pricing," the price of power is typically set by natural gas-fueled generation facilities (see Item 7. *Management's Discussion and Analysis of Financial Condition, and Results of Operations – Significant Activities and Events, and Items Influencing Future Performance*).

Transactions in ERCOT take place in two key markets: the day-ahead market and the real-time market. The day-ahead market is a voluntary, financial electricity market conducted the day before each operating day in which generators and purchasers of electricity may bid for one or more hours of electricity supply or consumption. The real-time market is a physical market in which electricity is dispatched and priced in five-minute intervals. The day-ahead market provides market participants with visibility into where prices are expected to clear, and the prices are not impacted by subsequent events. Conversely, the real-time market exposes purchasers to the risk of transient operational events and price spikes. These two markets allow market participants to manage their risk profile by adjusting their participation in each market. In addition, ERCOT uses ancillary services to maintain system reliability, including regulation service, responsive reserve service, and non-spinning reserve service. Ancillary services are provided by generators and qualified loads to help maintain the stable voltage and frequency requirements of the transmission system. ERCOT currently procures ancillary services in the day-ahead market, but plans to implement co-optimization of energy and ancillary services in the real-time market by the end of 2025. Because ERCOT has one of the highest concentrations of wind and solar capacity generation among U.S. markets, the ERCOT market is more susceptible to fluctuations in wholesale electricity supply due to intermittent wind and solar production, making ERCOT more vulnerable to periods of generation scarcity. ERCOT implemented the ERCOT Contingency Reserve Service (ECRS) in June 2023 to further address the need for operating reserves to manage load and intermittent resource output uncertainty.

PJM — PJM is an RTO that manages the flow of electricity from approximately 183,000 MW of generation capacity to approximately 65 million customers in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

Like ERCOT, PJM administers markets for wholesale electricity and provides transmission planning for the region, utilizing a locational marginal pricing (LMP) methodology which calculates a price for every generator and load point within PJM. PJM operates day-ahead and real-time markets into which generators can bid to provide energy and ancillary services. PJM also administers a forward capacity auction, the Reliability Pricing Model (RPM), which establishes a long-term market for capacity. We have participated in RPM auctions for years up to and including PJM's planning year 2025-2026, which ends May 31, 2026. PJM's RPM auction for planning year 2026-2027 was delayed and is expected to be run in July 2025. We also enter into bilateral capacity transactions. PJM's Capacity Performance (CP) rules were designed to improve system reliability and include penalties for under-performing units and reward for over-performing units during shortage events. Full transition of the capacity market to CP rules occurred in planning year 2020-2021. An independent market monitor continually monitors PJM markets to ensure a robust, competitive market and to identify improper behavior by any entity.

ISO-NE — ISO-NE is an ISO that manages the flow of electricity from approximately 30,600 MW of winter generation capacity to approximately 15 million customers in the states of Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island, and Maine.

ISO-NE dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Its energy markets allow market participants to buy and sell energy and ancillary services at prices established through real-time and day-ahead auctions. Energy prices vary among the locations in ISO-NE and are largely influenced by transmission constraints and fuel supply. ISO-NE offers the Forward Capacity Market where capacity prices are determined through auctions currently run three years prior to the capacity delivery year. ISO-NE is working with stakeholders to transition to a prompt capacity market for the delivery year starting in June 2028. Performance incentive rules have the potential to increase capacity payments for those resources that are providing excess energy or reserves during a shortage event, while penalizing those that produce less than the required level.

NYISO — NYISO is an ISO that manages the flow of electricity from approximately 37,100 MW of installed summer generation capacity to approximately 20 million New York customers.

NYISO dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Its energy markets allow market participants to buy and sell energy and ancillary services at prices established through real-time and day-ahead auctions. Energy prices vary among the regional zones and locations in the NYISO and are largely influenced by transmission constraints and fuel supply. NYISO offers the Installed Capacity Market, a forward capacity market where capacity prices are determined through auctions. Strip auctions occur one to two months prior to the commencement of a six-month seasonal planning period. Subsequent auctions provide an opportunity to sell excess capacity for the balance of the seasonal planning period or the upcoming month. Due to the short-term nature of the NYISO-operated capacity auctions and a relatively liquid bilateral market for NYISO capacity products, our Independence facility sells a significant portion of its capacity through bilateral transactions. The balance is cleared through the seasonal and monthly capacity auctions.

MISO — MISO is an RTO that manages the flow of electricity from approximately 202,000 MW of installed generation capacity to approximately 45 million customers in all or parts of Iowa, Minnesota, North Dakota, Wisconsin, Michigan, Kentucky, Indiana, Illinois, Missouri, Arkansas, Mississippi, Texas, Louisiana, Montana, South Dakota, and Manitoba, Canada.

MISO dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Its energy markets allow market participants to buy and sell energy and ancillary services at prices established through real-time and day-ahead auctions. Energy prices vary among the regional zones and locations in MISO and are largely influenced by transmission constraints and fuel supply. An independent market monitor is responsible for evaluating the performance of the markets and identifying conduct by market participants or MISO that may compromise the efficiency or distort the outcome of the markets.

MISO administers a one-year Planning Resource Auction (PRA) for the next planning year from June 1st of the current year to May 31st of the following year. MISO's PRA currently uses a vertical demand curve that can result in more volatile capacity prices. In 2022, FERC approved MISO's proposal to change the annual Planning Resource Auction into a seasonal auction, effective for the 2023-2024 planning year. Starting with the PRA for the 2025-2026 planning year, MISO will begin using a sloped demand curve. We participate in these auctions with open capacity that has not been committed through bilateral or retail transactions. We also participate in the MISO annual and monthly financial transmission rights auctions to manage the cost of our transmission congestion, as measured by the congestion component of the LMP price differential between two points on the transmission grid across the market area.

CAISO — CAISO is an ISO that manages the flow of electricity to approximately 32 million customers primarily in California, representing approximately 80% percent of the state's electric load.

Energy is priced in CAISO utilizing an LMP methodology. The capacity market is comprised of Generic, Flexible, and Local Resource Adequacy (RA) Capacity, which is administered by the California Public Utilities Commission (CPUC). Unlike other centrally cleared capacity markets, the resource adequacy markets in California are primarily bilaterally traded markets. In 2020, the CPUC introduced a central procurement entity for Local RA Capacity effective for the 2023 compliance year. The central procurement entity runs a pay-as-bid auction for Local RA Capacity. In November 2016, CAISO implemented a voluntary capacity auction for annual, monthly, and intra-month procurement to cover for deficiencies in the market. The voluntary Competitive Solicitation Process, which FERC approved in October 2015, is a modification to the Capacity Procurement Mechanism (CPM) and provides another avenue to sell RA capacity.

Wholesale Operations — Our wholesale commodity risk management group is responsible for dispatching our generation fleet in response to market needs after implementing portfolio optimization strategies, thus linking and integrating the generation fleet production with our retail customer and wholesale sales opportunities. Market demand, also known as load, faced by electric power systems, such as those we operate in, varies from moment to moment as a result of changes in business and residential demand, which is often driven by weather. Unlike most other commodities, the production and consumption of electricity must remain balanced on an instantaneous basis. There is a certain baseline demand for electricity across an electric power system that occurs throughout the day, which is typically satisfied by baseload generation units with low variable operating costs. Baseload generation units can also increase output to satisfy certain incremental demand and reduce output when demand is unusually low. Intermediate/load-following generation units, which can more efficiently change their output to satisfy increases in demand, typically satisfy a large proportion of changes in intraday load as they respond to daily increases in demand or unexpected changes in supply created by reduced generation from renewable resources or other generator outages. Peak daily loads may be satisfied by peaking units. Peaking units are typically the most expensive to operate, but they can quickly start up and shut down to meet brief peaks in demand. In general, baseload units, intermediate/load following units, and peaking units are dispatched into the ISO/RTO grid in order from lowest to highest variable cost. Price formation is typically based on the highest variable cost unit that clears the market to satisfy system demand at a given point in time.

Our commodity risk management group enters into electricity, natural gas, and other commodity derivative contracts to reduce exposure to price fluctuations with the goal of reducing volatility of future revenues and fuel costs for our generation facilities and purchased power costs for our Retail segment.

Seasonality

The demand for and market prices of electricity and natural gas are affected by weather. As a result, our operating results are impacted by extreme or sustained weather conditions and may fluctuate on a seasonal basis. Typically, demand for and the price of electricity is higher in the summer and winter seasons, when the temperatures are more extreme, and the demand for and price of natural gas is also generally higher in the winter. More severe weather conditions such as heat waves or extreme winter weather have made, and may make, such fluctuations more pronounced. The pattern of this fluctuation may change depending on, among other things, the retail load served and the terms of contracts to purchase or sell electricity.

Competition

Competition in the markets in which we operate is impacted by electricity and fuel prices, congestion along the power grid, subsidies provided by state and federal governments for new and existing generation facilities, including renewables generation and battery ESS, new market entrants, construction of new generation assets, technological advances in power generation, the actions of environmental and other regulatory authorities, and other factors. We primarily compete with other electricity generators and retailers based on our ability to generate electric supply, market and sell electricity at competitive prices, and efficiently utilize transportation from third-party pipelines and transmission from electric utilities to deliver electricity to end-users. Competitors in the generation and retail power markets in which we participate include numerous regulated utilities, industrial companies, non-utility generators, competitive subsidiaries of regulated utilities, independent power producers, REPs, and other energy marketers. See Item 1A. *Risk Factors* for additional information concerning the risks faced with respect to the markets in which we operate.

Business Strategy

Vistra is the largest producer of power in deregulated markets in the U.S. with annual expected generation of over 200 TWh as of December 31, 2024.

Vistra is guided by four core principles:

- *We do business the right way.* Every decision we make and action we take will be evidence of the utmost integrity and compliance.
- *We compete to win.* We will create the leading integrated energy company with an unmatched work ethic, an analysis-driven and disciplined culture with strong leadership and decision-making throughout the organization.
- *We work as a team.* We are committed to each other, everything we do and to the success of our company.
- *We care about our key stakeholders.* We respect our fellow employees, we focus on our customers, and we care about our communities where we live and do business. We will maintain productive and respectful relationship with our legislators, regulators and community leaders.

To align with our four core principles, our focus is on the execution of our strategic priorities as follows:

Long-term, attractive earnings profile through the integrated business model. Our integrated business model distinguishes us from our electricity competitors as it combines our reliable and efficient diversified generation fleet totaling approximately 41,000 MW of capacity, with our commercial operations, including commodity risk management capabilities, and our best-in-class retail energy platform. We believe integrating retail with power generation stands as a fundamental competitive advantage that mitigates the impact of commodity price fluctuations and enhances the stability and predictability of our cash flows.

Disciplined capital allocation. We strive to make thoughtful decisions when allocating our free cash flow to balance growth opportunities with returning capital to our stakeholders through share repurchases, dividends, and debt reduction.

Maintaining a resilient balance sheet. We seek to manage our financial leverage by maintaining a strong balance sheet which ensures our access to diverse sources of liquidity. We believe this provides financial flexibility for our capital allocation decisions, including executing on organic growth opportunities, engaging in mergers and acquisitions, opportunistic debt reduction, or returning capital to our stockholders.

Strategic energy transition that supports the reliability, affordability, and sustainability of the electric grid. As one of the largest electricity generators in the U.S., Vistra has led the way in decarbonization efforts and is committed to sustainability, setting aggressive targets, and transitioning our fleet to low-to-no carbon resources, all while balancing our obligations to our stakeholders. While the way we generate electricity may be changing, our essential role in providing reliable and affordable electricity is not.

Human Capital Resources

Vistra's approach to human capital management is guided by our core values. Our core values apply to all employees, suppliers and contractors and guide how we interact with our partner companies, communities, the environment and all other stakeholders. We aim to conduct all aspects of our business in accordance with these core values, which serve as the cultural foundation of the Company.

Vistra believes our most valuable asset is our talented, dedicated and dynamic group of employees who work together to achieve our objectives, and our top priority is ensuring their safety. As of December 31, 2024, we had approximately 6,850 full-time employees, including approximately 1,940 employees under collective bargaining agreements.

Safety

Vistra's mindset around safety is exemplified by our motto: *Best Defense. Everyone wins. No one gets hurt.* Our safety culture revolves around people and human performance. We place a high importance on continuous improvement, along with a keen focus on numerous learning and error-prevention tools. To facilitate a learning environment, our various operating plants share their investigations and learnings of all safety events with all operations employees on weekly calls. The information is presented by front-line employees and supported by management. The lessons from each event are shared across the fleet to prevent similar incidents at other locations. All personnel at Vistra locations are encouraged to be actively involved in the safety process. Managers are required to participate in safety engagements with staff to enable constant communication and sustained interaction. In 2024, the generation fleet conducted more than 51,000 leadership safety engagements across the fleet continuing our employee driven safety program focused on engagement of all employees.

Our focus on reducing the severity of injuries for both our employees and contractors who work with us has shown positive results. Since the implementation of our Best Defense safety program, the number of serious injuries or fatalities has decreased significantly. Although we do not focus on recordable incidents, our Total Recordable Incident rate (TRIR) for company employees was 0.72, in the top quartile as compared to the Edison Electric Institute (EEI) 2023 Total Company Injury Data for companies of comparable size. We encourage near-miss reporting and review of events to promote a learning environment. In 2024, safety learning calls were held every week where near-miss and safety events were reviewed by our operating teams to promote learning across the fleet.

All Vistra employees are covered by our safety program. Corporate and retail employees are required to complete periodic training on safety topics through our online learning management system. Employees who are located at a power plant are required to complete trainings based on job function, which is also tracked through our central learning management system. In addition, the Company engages an independent third-party conformity assessment and certification vendor to manage adherence to our safety standards for all vendors and contractors who work at our plants. In addition, we work closely with our suppliers and contractors to ensure our safety practices are upheld.

All of our power plant facilities have effective health and safety programs and comply with OSHA regulations. In addition to compliance, our generation fleet has a total of 14 plants that have been awarded the Voluntary Protection Program (VPP) Star designation by the OSHA for superior demonstration of effective safety and health management systems and for maintaining injury and illness rates below the national averages for our industry. Our Casco Bay, Forney, Lamar, and Liberty generation facilities completed reevaluations and were recommended to continue as VPP Star in 2024. VPP Star status is the highest designation of OSHA's Voluntary Protection Programs. The achievement recognizes employers and workers who have implemented effective safety and health management systems and maintain injury and illness rates below national Bureau of Labor Statistics (BLS) averages for their respective industries. These sites are self-sufficient in their ability to control workplace hazards and are reevaluated every three to five years. Additionally, 32 of our power plants and mine locations have adopted a proactive Behavior Based Safety approach to safety which focuses on identifying and providing feedback on at-risk behaviors observed.

Our People

We recognize the value of having an inclusive workforce. Our employees reflect the communities we serve, ranging in age, gender, ethnicity, physical appearance, thoughts, styles, religions, nationality, education and numerous other traits. Creating and maintaining an environment where our employees feel appreciated for their talent and contribution enhances our ability to recruit and retain the best talent in the marketplace and to provide a work environment that allows all employees to continue to be their best.

Vistra is active in our communities through employee-led initiatives, business teams, and collaborations with many community agencies, such as United Way. Another way we engage with our communities is through our supply chain initiative, which seeks to create a dynamic supply chain that identifies suppliers of all sizes and across our markets that are able to provide quality products and services to the business.

Training and Development

We believe the development of employees at all levels is critical to Vistra's current and future success. We have launched key programs to develop leaders at all levels of the organization. Vistra's Essentials of Leadership provides new managers with skills to lead organizations in situational leadership, business acumen, and exposes them to best practices from across the company. We continue to evaluate and refine our programs as the development needs of our employees change. In 2024, Vistra began including the former Energy Harbor employees and leaders in leadership and front-line training programs to accelerate the integration of Vistra's culture with the new nuclear sites.

Vistra also provides many other training and development programs to help grow and develop employees at every level, including online learning platform courses, learning management system courses, recorded webinars and presentations, self-paced development and employee-specific skill training. The Vistra Learning Community is our online platform that strategically supports employees in completing thousands of hours of professional training to support continuing education requirements for their respective professional licenses, including accounting, legal and nuclear. In 2024, Vistra continued its formal mentoring program available to all employees to focus on topics like organizational knowledge, career development, individual development, collaboration and leadership. Over 450 employees participated in 2024. In 2024, Vistra launched physical and online Career Hubs, where employees can go to learn about a wide variety of careers within the company and identify skills they need to develop to pursue those roles. In addition, all full-time employees, other than those in a collective bargaining unit, receive a formal performance review guiding development and improving results of the business.

Employee Benefits

Maintaining attractive benefits and pay are important for recruiting and retaining talent. We are committed to maintaining an equitable compensation structure, including performing annual salary reviews by employee category level within significant locations of operations. Eligible full- and part-time employees are provided access to medical, prescription drug, dental, vision, life insurance, accidental death and dismemberment, long-term disability coverage, accident coverage, critical illness coverage and hospital indemnity coverage. Regular full-time employees are eligible for short-term disability benefits, and all employees are eligible for the employee assistance program, parental leave, maternity leave and a 401(k) plan through which the Company matches employee contributions up to 6%.

Wellness

We believe a healthy workforce leads to greater well-being at work and at home. To help keep our workforce healthy, we offer access to on-site medical clinics at six locations. Our healthcare plans are also designed to reward employees for getting annual physicals, age and gender health screenings and immunizations. In addition, our employee medical plans promote mental health and emotional wellness and offer resources for employees seeking assistance. Fitness centers in multiple facilities offer cardio equipment, a selection of free weights and exercise mats. Our employee-led wellness team engages our people to get active and support causes that promote healthy living. With support from the company, the wellness team covers the registration costs for employees to participate in running and cycling events throughout the year.

Environmental Regulations and Related Considerations

We are subject to extensive environmental regulation by governmental authorities, including the EPA and the environmental regulatory bodies of states in which we operate. The EPA has finalized or proposed several regulatory actions establishing new requirements for control of certain emissions from sources, including electricity generation facilities. However, in January 2025, President Trump issued a series of executive orders, including an order titled Unleashing American Energy (the Order) that ordered that all federal agencies are to review all existing regulations, orders, and other actions for consistency with the policy goals, and develop an action plan within 30 days to resolve any policy inconsistencies. The Order requires the EPA to review the GHG, CSAPR, Legacy CCR and ELG rules discussed below. Additionally, the Order states the U.S. Attorney General may request a stay of the litigation involving these rules while the EPA conducts its reviews. See Item 1A. *Risk Factors* and Note 15 to the Financial Statements for additional information.

Climate Change

There is continuing interest from our stakeholders domestically and internationally on global climate change and how GHG emissions, such as CO_2, contribute to global climate change. GHG emissions from the combustion of fossil fuels, primarily by our coal-fueled-generation plants as well as our natural gas-fueled generation plants represent the substantial majority of our total GHG emissions. CO_2, methane and nitrous oxide are emitted in this combustion process, with CO_2 representing the largest portion of these GHG emissions. We estimate that our generation facilities produced approximately 95 million short tons of CO_2 in the year ended 2024. Vistra's carbon intensity for power generation improved from 0.56 short tons of CO_2 per MWh in 2023 to 0.48 short tons of CO_2 per MWh in 2024, a 15% year-over-year improvement driven by our Energy Harbor acquisition.

To manage our environmental impact from our business activities and reduce our emissions profile, Vistra set emissions reduction targets. Vistra is targeting to achieve a 60% reduction in Scope 1 and Scope 2 CO_2 equivalent emissions by 2030 as compared to a 2010 baseline with a long-term goal to achieve net-zero carbon emissions by 2050, assuming necessary advancements in technology and supportive market constructs and public policy. Since 2010, Vistra has retired more than 15,100 MW of coal and natural gas power plants resulting in a 50% reduction in carbon dioxide (CO_2) emissions, a 66% reduction in nitrogen oxide (NO_X) emissions, and an 90% reduction in sulfur dioxide (SO_2) emissions through year-end 2024, compared to a 2010 baseline. Vistra also has targets validated through the Science Based Targets initiative (SBTi). Our near-term science-based targets are to reduce absolute scope 1 and 2 GHG emissions 58% by 2028 from a 2018 base year, reduce absolute scope 1 and 3 GHG emissions from all sold electricity 58% within the same timeframe, and reduce absolute scope 3 GHG emissions from use of sold products 42% within the same timeframe. Vistra is exploring multiple options to meet these targets, but we must balance these efforts with the need to prioritize reliability and affordability for our customers.

The evolution of our generation portfolio is focused on ensuring reliability and affordability in the markets we serve with an emphasis on resilient dispatchable assets complemented by zero-carbon assets. We seek to serve our customers through a variety of generation sources, including efficient natural gas units, nuclear generation, renewables, and battery ESS, while we also continuously explore new technologies with lower carbon footprints.

We have already taken or announced significant steps to transform our generation portfolio with the goal of maintaining reliability while also reducing the emissions intensity of our generation fleet, including:

- *Acquisition of Nuclear Generation Facilities* — In 2024, we acquired 4,048 MW of nuclear generation facilities in PJM from Energy Harbor.
- *Re-powered generation assets* — In May 2024, we announced our intention to repower the coal-fueled Coleto Creek Power Plant near Goliad, Texas as a natural-gas fueled plant with up to 600 MW of capacity.
- *Uprated capacity at existing natural gas plants* — Additional capacity has been added to existing natural gas plants through technological upgrades improving efficiency and overall fleet intensity.
- *Battery Energy Storage Projects* — As of December 31, 2024, we owned battery ESS totaling 750 MW in California, 270 MW in Texas and 4 MW in Illinois. We have announced our plans to develop additional battery ESS at retired or to-be-retired plant sites in Illinois.
- *Solar Projects* — As of December 31, 2024, we owned solar generations facilities totaling 338 MW in Texas and 112 MW in Illinois. We have announced our plans to develop additional solar generation facilities in Texas, with expected commercial operation dates beginning in 2025, and additional solar generation facilities at retired or to-be retired plant sites in Illinois with expected commercial operation dates beginning in 2026.

We will only invest in growth projects if we are confident in the expected returns.

Green Finance Framework

In December 2021, we announced the publication of our Green Finance Framework, which allows us to issue green financial instruments to fund new or existing projects that support renewable energy and energy efficiency with alignment to our ESG strategy.

Greenhouse Gas Emissions (GHG)

In May 2023, the EPA released a proposal regulating power plant GHG emissions, while also proposing to repeal the Affordable Clean Energy (ACE) rule that had been finalized by the EPA in July 2019. In May 2024, the EPA published a final GHG rule that repealed the ACE rule and sets limits for (a) new natural gas-fired combustion turbines and (b) existing coal-, oil- and natural gas-fired steam generation units. The standards are based on technologies such as carbon capture and sequestration/storage (CCS) and natural gas co-firing. Starting in 2030, the rule would begin to require more CO_2 emissions control at certain existing fossil fuel-fired steam generating units, with more stringent standards beginning in 2032 for coal-fired units that plan to operate for a longer period of time. For new natural gas combustion turbines that operate more frequently, the rule would phase in increasingly stringent CO_2 requirements over time. Under the rule, states would be required to submit plans to the EPA within 24 months of the rule's publication in the Federal Register that provide for the establishment, implementation, and enforcement of standards of performance for existing sources. These state plans must generally establish standards that are at least as stringent as the EPA's emission guidelines. Under the rule, existing coal-fired steam generation units that will operate on or after January 1, 2039 must start complying with their standards of performance (based on application of CCS with 90 percent capture) by January 1, 2032. Units that are permanently retiring before January 1, 2039, but after December 31, 2031, must start complying with their standards of performance (based on co-firing with 40 percent natural gas on a heat input basis) beginning on January 1, 2030. Units permanently retiring by January 1, 2032 are exempt from the rule. Given our previously announced coal unit retirement commitments, our Martin Lake and Oak Grove plants are the only coal units that are subject to this rule. Our Graham, Lake Hubbard, Stryker Creek and Trinidad oil/natural gas facilities are also regulated under this rule. None of our existing large or small combustion turbines are subject to this rule. The rule also regulates any new gas units. For new combustion turbine units, the rule establishes three different categories depending on how intensively those units are operated, with immediate compliance obligations for all three categories but more stringent standards beginning in 2032 only for the category of units operating the most intensively. Following finalization of the rule in May 2024, 17 petitions for review from various states, industry groups and companies were filed in the D.C. Circuit Court along with multiple motions to stay the rule. We are participating in an industry coalition challenging the rule. In July 2024, the D.C. Circuit Court denied the motions to stay and a number of parties subsequently filed an emergency request with the U.S. Supreme Court to stay the rule which was denied in October 2024. Oral argument on the merits of the legal challenges to the rule was held in December 2024 before the D.C. Circuit Court. In February 2025, the D.C. Circuit granted the unopposed motion filed by the Department of Justice on behalf of the EPA, holding the litigation in abeyance for a period of 60 days while the new leadership at the EPA evaluates the rule and determines how it wishes to proceed.

State Regulation of GHGs

Many states where we operate generation facilities have, are considering, or are in some stage of implementing, state-only regulatory programs intended to reduce emissions of GHGs from stationary sources as a means of addressing climate change.

Regional Greenhouse Gas Initiative (RGGI) — RGGI is a state-driven GHG emission control program that took effect in 2009 and was initially implemented by ten New England and Mid-Atlantic states to reduce CO_2 emissions from power plants. The participating RGGI states implemented a cap-and-trade program. Compliance with RGGI can be achieved by reducing emissions, purchasing or trading allowances, or securing offset allowances from an approved offset project. We are required to hold allowances equal to at least 50 percent of emissions in each of the first two years of the three-year control period.

In December 2017, the RGGI states released an updated model rule with changes to the CO_2 budget trading program, including an additional 30 percent reduction in the CO_2 annual cap by the year 2030, relative to 2020 levels. RGGI is currently conducting its third program review which may include an updated model rule.

Our generation facilities in Connecticut, Maine, Massachusetts, New Jersey, New York and Virginia emitted approximately 11 million short tons of CO_2 during 2024. The spot market price of RGGI allowances required to operate these facilities as of December 31, 2024 was approximately $24.13 per allowance. While the cost of allowances required to operate our RGGI-affected facilities is expected to increase in future years, we expect that the cost of compliance would be reflected in the power market, and the actual impact to gross margin would be largely offset by an increase in revenue.

Massachusetts — In August 2017, the Massachusetts Department of Environmental Protection (MassDEP) adopted final rules establishing an annual declining limit on aggregate CO_2 emissions from 21 in-state fossil-fueled electricity generation units. The rules establish an allowance trading system under which the annual aggregate electricity generation unit sector cap on CO_2 emissions declines from 8.96 million metric tons in 2018 to 1.8 million metric tons in 2050. MassDEP allocated emission allowances to affected facilities for 2018. Beginning in 2019, the allocation process transitioned to a competitive auction process whereby allowances are partially distributed through a competitive auction process and partially distributed based on the process and schedule established by the rule. Beginning in 2021, all allowances were distributed through the auction. Limited banking of unused allowances is allowed.

Virginia — In May 2019, the Virginia Department of Environmental Quality issued a final rule to adopt a carbon cap-and trade program for fossil-fueled electricity generation units, including our Hopewell facility, beginning in 2020. The program is based on the RGGI proposed 2017 model rule and linked Virginia to RGGI in 2021. The Governor of Virginia issued an executive order in January 2022 to begin the process of removing the state from RGGI. The Virginia State Pollution Control Board withdrew the state from RGGI at the end of 2023, coinciding with the end of the program's three-year compliance period and contract with RGGI, Inc. In August 2023, opponents of the state's action filed suit seeking a stay alleging withdrawal from RGGI is impermissible without new legislation. In November 2024, a state circuit court judge ruled that the removal of Virginia from RGGI was unlawful, but the state has moved to stay the circuit court's judgment. Virginia is not participating in RGGI at this time.

New Jersey — In January 2018, the Governor of New Jersey signed an executive order directing the state's environmental agency and public utilities board to begin the process of rejoining RGGI, and New Jersey formally rejoined RGGI in June 2019. In June 2019, New Jersey adopted two rules that govern New Jersey's reentry into the RGGI auction and distribution of the RGGI auction proceeds.

Pennsylvania — In April 2022, the Pennsylvania Environmental Quality Board finalized regulations that would establish Pennsylvania's participation in RGGI. In July 2022, the Commonwealth Court of Pennsylvania (Commonwealth Court) took action to uphold a preliminary injunction over Pennsylvania's RGGI regulations. The Pennsylvania Supreme Court denied a request for emergency relief from the injunction in August 2022. In November 2023, the Commonwealth Court found that Pennsylvania cannot join RGGI without legislative approval and enjoined the Pennsylvania Department of Environmental Protection from implementing RGGI. The state has appealed this decision to the Pennsylvania Supreme Court where it is still pending. The Pennsylvania Department of Environmental Protections has indicated it will not seek to implement RGGI until the Pennsylvania Supreme Court acts. As a result, RGGI is not being implemented or enforced in Pennsylvania at this time.

California — Our assets in California are subject to the California Global Warming Solutions Act, which required the California Air Resources Board (CARB) to develop a GHG emission control program to reduce emissions of GHGs in the state to 1990 levels by 2020. In April 2015, the Governor of California issued an executive order establishing a new statewide GHG reduction target of 40 percent below 1990 levels by 2030 to ensure California meets its 2050 GHG reduction target of 80 percent below 1990 levels. We have participated in quarterly auctions or in secondary markets, as appropriate, to secure allowances for our affected assets.

In July 2017, California enacted legislation extending its GHG cap-and-trade program through 2030 and the CARB adopted amendments to its cap-and-trade regulations that, among other things, established a framework for extending the program beyond 2020 and linking the program to the new cap-and-trade program in Ontario, Canada beginning in January 2018.

Air Emissions

The Clean Air Act (CAA)

The CAA and comparable state laws and regulations relating to air emissions impose various responsibilities on owners and operators of sources of air emissions, which include requirements to obtain construction and operating permits, pay permit fees, monitor emissions, submit reports and compliance certifications, and keep records. The CAA requires that fossil-fueled electricity generation plants meet certain pollutant emission standards and have sufficient emission allowances to cover SO_2 emissions and in some regions NO_X emissions.

In order to ensure continued compliance with the CAA and related rules and regulations, we utilize various emission reduction technologies. These technologies include flue gas desulfurization (FGD) systems, dry sorbent injection (DSI), baghouses and activated carbon injection or mercury oxidation systems on select units and electrostatic precipitators, selective catalytic reduction (SCR) systems, low-NO_X burners and/or overfire air systems on all units.

Cross-State Air Pollution Rule (CSAPR) and Good Neighbor Plan

In 2016, the EPA finalized the Cross-State Air Pollution Rule Update (CSAPR Update) to address 22 states' obligations with respect to the 2008 ozone National Ambient Air Quality Standards (NAAQS). In 2019, following challenges by numerous parties, the D.C. Circuit Court found that the CSAPR Update did not fully address certain states' 2008 ozone NAAQS obligations. In October 2020, the EPA proposed an action to address the outstanding 2008 ozone NAAQS obligations in response to the D.C. Circuit Court's 2019 ruling. Vistra subsidiaries filed comments on that rulemaking in December 2020, and the EPA published a final rule in the Federal Register on April 30, 2021 that reduces ozone season NO_X budgets in certain states. We do not believe that the final rule causes a material adverse impact on our future financial results.

In October 2015, the EPA revised the primary and secondary ozone NAAQS to lower the 8-hour standard for ozone emissions during ozone season (May to September). As required under the CAA, in October 2018, the State of Texas submitted a State Implementation Plan (SIP) to the EPA demonstrating that emissions from Texas sources do not contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to the revised ozone NAAQS. In February 2023, the EPA disapproved Texas' SIP and the State of Texas, Luminant, certain trade groups, and others challenged that disapproval in the U.S. Court of Appeals for the Fifth Circuit (Fifth Circuit Court). In March 2023, those same parties filed motions to stay the EPA's SIP disapproval in the Fifth Circuit Court, and the EPA moved to transfer our challenges to the D.C. Circuit Court or have those challenges dismissed.

In April 2022, prior to the EPA's disapproval of Texas' SIP, the EPA proposed a Federal Implementation Plan (FIP) to address the 2015 ozone NAAQS. We, along with many other companies, trade groups, states and ISOs, including ERCOT, PJM and MISO, filed responsive comments to the EPA's proposal in June 2022, expressing concerns about certain elements of the proposal, particularly those that may result in challenges to electric reliability under certain conditions. In March 2023, the EPA administrator signed its final FIP, called the Good Neighbor Plan (GNP). The FIP applied to 22 states beginning with the 2023 ozone seasons. States where Vistra operates generation units that would be subject to this rule are Illinois, New Jersey, New York, Ohio, Pennsylvania, Texas, Virginia, and West Virginia. Texas would be moved into the revised (and more restrictive) Group 3 trading program previously established in the Revised CSAPR Update Rule that includes emission budgets for 2023 that the EPA says are achievable through existing controls installed at power plants. Allowances will be limited under the program and will be further reduced beginning in ozone season 2026 to a level that is intended to reduce operating time of coal-fueled power plants during ozone season or force coal plants to retire, particularly those that do not have selective catalytic reduction systems such as our Martin Lake power plant.

In May 2023, the Fifth Circuit Court granted our motion to stay the EPA's disapproval of Texas' SIP pending a decision on the merits and denied the EPA's motion to transfer our challenge to the D.C. Circuit Court. As a result of the stay, we do not believe the EPA has authority to implement the GNP FIP as to Texas sources pending the resolution of the merits, meaning that Texas will remain in Group 2 and not be subject to any requirements under the GNP FIP at least until the Fifth Circuit Court rules on the merits. Oral argument was heard in December 2023 before the Fifth Circuit Court. In June 2023, the EPA published the final FIP in the Federal Register, which included requirements as to Texas despite the stay of the SIP disapproval by the Fifth Circuit Court. In June 2023, the State of Texas, Luminant and various other parties also filed challenges to the GNP FIP in the Fifth Circuit Court, filed a motion to stay the FIP and confirm venue for this dispute in the Fifth Circuit Court. After the motion to stay and to confirm venue was filed, the EPA signed an interim final rule on June 29, 2023 that confirms the GNP FIP as to Texas is stayed. In February 2025, the Department of Justice filed a motion on behalf of the EPA in the Fifth Circuit Court, seeking to hold the litigation in abeyance while the new leadership at the EPA evaluates the rule and determines how it wishes to proceed. In February 2025, the State of Texas filed a response opposing the requested abatement, which we joined. In July 2023, the Fifth Circuit Court ruled that the GNP FIP challenge would be held in abeyance pending the resolution of the litigation on the SIP disapproval and denied the motion to stay as not needed given the EPA's administrative stay. In a related action brought by other states and parties challenging the GNP FIP, in June 2024, the U.S. Supreme Court granted a stay of the GNP FIP pending a review of the merits by the D.C. Circuit Court and any further appeal to the U.S. Supreme Court. As a result, the GNP FIP is now stayed for all covered states until the courts resolve the legality of the FIP. In February 2025, the D.C. Circuit Court denied a motion filed by the Department of Justice on behalf of the EPA, seeking to hold the litigation in abeyance for a period of 60 days while the new leadership at the EPA evaluates the rule and determines how it wishes to proceed.

Regional Haze — Reasonable Progress and Best Available Retrofit Technology (BART) for Texas

The Regional Haze Program of the CAA establishes "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I federal areas which impairment results from man-made pollution." There are two components to the Regional Haze Program. First, states must establish goals for reasonable progress for Class I federal areas within the state and establish long-term strategies to reach those goals and to assist Class I federal areas in neighboring states to achieve reasonable progress set by those states towards a goal of natural visibility by 2064. Second, certain electricity generation units built between 1962 and 1977 are subject to BART standards designed to improve visibility if such units cause or contribute to impairment of visibility in a federal class I area.

In October 2017, the EPA issued a final rule addressing BART for Texas electricity generation units, with the rule serving as a partial approval of Texas' 2009 SIP and a partial FIP. For SO_2, the rule established an intrastate Texas emission allowance trading program as a "BART alternative" that operates in a similar fashion to a CSAPR trading program. The program includes 39 generation units (including the Martin Lake, Big Brown, Monticello, Sandow 4, Coleto Creek, Stryker 2, and Graham 2 plants). The compliance obligations in the program started on January 1, 2019. For NO_X, the rule adopted the CSAPR's ozone program as BART and for particulate matter, the rule approved Texas' SIP that determines that no electricity generation units are subject to BART for particulate matter. In August 2020, the EPA issued a final rule affirming the prior BART final rule but also included additional revisions that were proposed in November 2019. Challenges to both the 2017 rule and the 2020 rules have been consolidated in the D.C. Circuit Court, where we have intervened in support of the EPA. We are in compliance with the rule, and the retirements of our Monticello, Big Brown, and Sandow 4 plants have enhanced our ability to comply. The EPA is in the process of reconsidering the BART rule, and the challenges in the D.C. Circuit Court have been held in abeyance pending the EPA's final action on reconsideration. In May 2023, a proposed BART rule was published in the Federal Register that would withdraw the trading program provisions of the prior rule and would establish SO_2 limits on six facilities in Texas, including Martin Lake and Coleto Creek. Under the current proposal, compliance would be required within 3 years for Martin Lake and 5 years for Coleto Creek. Due to the announced shutdown for Coleto Creek, we do not anticipate any impacts at that facility, and we are evaluating potential compliance options at Martin Lake should this proposal become final. We submitted comments to the EPA on this proposal in August 2023.

National Ambient Air Quality Standards (NAAQS)

The CAA requires the EPA to regulate emissions of pollutants considered harmful to public health and the environment. The EPA has established NAAQS for six such pollutants, including SO_2 and ozone. Each state is responsible for developing a SIP that will attain and maintain the NAAQS. These plans may result in the imposition of emission limits on our facilities.

SO_2 Designations for Texas

In November 2016, the EPA finalized its nonattainment designations for counties surrounding our Martin Lake generation plant and our now retired Big Brown and Monticello plants. The final designations require Texas to develop nonattainment plans for these areas. In February 2017, the State of Texas and Luminant filed challenges to the nonattainment designations in the Fifth Circuit Court. In August 2019, the EPA issued a proposed Error Correction Rule for all three areas, which, if finalized, would have revised its previous nonattainment designations and each area at issue would be designated unclassifiable. In May 2021, the EPA finalized a "Clean Data" determination for the areas surrounding the retired Big Brown and Monticello plants, redesignating those areas as attainment based on monitoring data supporting an attainment designation. In June 2021, the EPA published two notices; one that it was withdrawing the August 2019 Error Correction Rule and a second separate notice denying petitions from Luminant and the State of Texas to reconsider the original nonattainment designations. We, along with the State of Texas, challenged that EPA action and have consolidated it with the pending challenge in the Fifth Circuit Court, and this case was argued before the Fifth Circuit Court in July 2022. In September 2021, the TCEQ considered a proposal for its nonattainment SIP revision for the Martin Lake area and an agreed order to reduce SO_2 emissions from the plant. The proposed agreed order associated with the SIP proposal reduced emission limits as of January 2022. Emission reductions required are those necessary to demonstrate attainment with the NAAQS. The TCEQ's SIP action was finalized in February 2022 and has been submitted to the EPA for review and approval. In January 2024, in a split decision, the Fifth Circuit Court denied the petitions for review we and the State of Texas filed over the EPA's 2016 nonattainment designation for SO_2 for the area around Martin Lake. As a result of this decision, the EPA's nonattainment designation – originally made in 2016 – remains in place. In February 2024, we filed a petition asking the full Fifth Circuit Court to review the panel decision issued in January 2024, which remains pending before the full Fifth Circuit Court. In August 2024, the EPA proposed a Finding of Failure to attain the SO_2 standard for Rusk and Panola Counties, a partial approval and partial disapproval of the Texas SIP and a proposed federal plan for the area. In December 2024, the EPA finalized the Finding of Failure to attain the standard and stated that it would take final action of the SIP partial approval and disapproval in a future action. In February 2025, we, along with the State of Texas, filed a challenge to the Finding of Failure in the Fifth Circuit Court.

Ozone Designations

The EPA issued a final rule in October 2015 lowering the ozone NAAQS from 75 to 70 parts per billion. Areas surrounding our Dicks Creek, Miami Fort and Zimmer facilities in Ohio, our Calumet facility in Illinois and our Wise, Ennis and Midlothian facilities in Texas were designated marginal nonattainment areas in June 2018 by the EPA with an attainment deadline of August 2021. In June 2022, the areas surrounding our Ohio Dicks Creek and Miami Fort facilities were redesignated "attainment." The EPA redesignated the area around our Texas Wise, Ennis and Midlothian facilities to "moderate" in October 2022 and again "bumped up" the classification to serious in June 2024. Middlesex County in New Jersey, where our Sayreville facility is located, was designated a "moderate" nonattainment area. In July 2024, the state of New Jersey, in collaboration with the states of New York and Connecticut requested a voluntary bump up of the New York-Northern New Jersey-Long Island nonattainment area, which includes Middlesex County where our Sayreville facility is located. States will be required to develop SIPs to address emissions in areas with a higher (more stringent) classification.

Particulate Matter

In February 2024, the EPA issued a rule addressing the annual health-based national ambient air quality standards for fine particulate matter (or PM2.5). In general, the rule lowers the level of the annual PM2.5 standard from 12.0 micrograms per cubic meter (µg/m3) to 9.0 µg/m3. The effective date of the rule is 60 days from publication in the Federal Register, and the earliest attainment date for areas exceeding the new standard is 2032. Based on 2021-2023 design value associated with the rule, we have just four plants (Calumet (Illinois), Dicks Creek and Miami Fort (Ohio), and Lake Hubbard (Texas)) operating in areas where the air quality monitoring data are currently exceeding the new PM2.5 standard. We have previously announced that our Miami Fort generation facility will close by the end of 2027. States will have to develop a plan (by late 2027 at the earliest) to get those areas into attainment and there would be a possibility that additional controls would be required for those sites. However, before the state begins this planning process, the designation process will occur within two years from the issuance of the final rule. The states develop recommendations about the boundaries of the nonattainment counties and the EPA must finalize the designations including the boundaries of each nonattainment area.

Coal Combustion Residuals (CCR)/Groundwater

The combustion of coal to generate electric power creates large quantities of ash and byproducts that are managed at power generation facilities in dry form in landfills and in wet form in surface impoundments. Each of our coal-fueled plants has at least one CCR surface impoundment.

CCR Rule Revisions and Extension Applications

The EPA's CCR rule, which took effect in October 2015, establishes minimum federal requirements for the construction, retrofitting, operation and closure of, and corrective action with respect to, existing and new CCR landfills and surface impoundments, as well as inactive CCR surface impoundments. The requirements include location restrictions, structural integrity criteria, groundwater monitoring, operating criteria, liner design criteria, closure and post-closure care, recordkeeping and notification. The deadlines for beginning and completing closure vary depending on several factors. The Water Infrastructure Improvements for the Nation Act (the WIIN Act), which was enacted in December 2016, provides for EPA review and approval of state CCR permit programs.

In August 2018, the D.C. Circuit Court issued a decision that vacates and remands certain provisions of the 2015 CCR rule, including an applicability exemption for legacy impoundments. In August 2020, the EPA issued a final rule establishing a deadline of April 11, 2021 to cease receipt of waste and initiate closure at unlined CCR impoundments. The 2020 final rule allows a generation plant to seek the EPA's approval to extend this deadline if no alternative disposal capacity is available and either a conversion to comply with the CCR rule is underway or retirement will occur by either 2023 or 2028 (depending on the size of the impoundment at issue).

Prior to the November 2020 deadline to seek extensions, we submitted applications to the EPA requesting compliance extensions under both conversion and retirement scenarios. In January 2022, the EPA determined that our conversion and retirement applications for our CCR facilities were complete but has not yet proposed action on any of those applications.

In addition, in January 2022, the EPA also made a series of public statements, including in a press release, that purported to impose new, more onerous closure requirements for CCR units. In April 2022, we, along with the Utility Solid Waste Activities Group (USWAG), a trade association of over 130 utility operating companies, energy companies, and certain other industry associations, filed petitions for review with the D.C. Circuit Court and asked the court to determine that the EPA cannot implement or enforce the new purported requirements because the EPA has not followed the required procedures. The State of Texas and the TCEQ intervened in support of the petitions filed by the Vistra subsidiaries and USWAG, and various environmental groups have intervened on behalf of the EPA. In June 2024, the D.C. Circuit Court dismissed the petitions filed challenging the EPA's January 2022 statements because it found the statements did not amend the existing CCR regulations, and thus the D.C. Circuit Court did not have jurisdiction to review them.

Legacy CCR Rulemaking

In May 2024, the EPA published a final rule that expands coverage of groundwater monitoring and closure requirements to the following two new categories of units: (a) legacy CCR surface impoundments which are CCR surface impoundments that no longer receive CCR but contained both CCR and liquids on or after October 19, 2015 and (b) "CCR management units" (CCRMUs) which generally could encompass noncontainerized ash deposits greater than one ton and impoundments and landfills that closed prior to October 19, 2015. As part of the rule, the EPA identified numerous CCR management units across the country, including ten of our potential units. The Vermilion ash ponds discussed below are the only unit which we believe qualify as a legacy CCR surface impoundment and given our closure plan for that site we do not believe the rule will have any impact on that site. CCRMUs with 1,000 or more tons of CCR must comply with the CCR's groundwater monitoring, corrective action, closure and post-closure requirements. For CCRMUs, complete facility evaluation reports are due within 33 months after publication of the rule, initial groundwater reports are due January 31, 2029, and the deadline to initiate closure, if needed, will start in 2029. Closure of the CCRMUs may also be deferred beyond those dates depending on certain factors, including where the CCRMU is located beneath critical infrastructure. In addition, certain closures may not be required when closure was previously approved under a state program. Because facility evaluation reports will determine our unit-specific compliance obligations, we cannot determine them at this time. In August 2024, we, along with USWAG, several other generating companies, and 17 states, including Texas, filed a challenge to the rule in the D.C. Circuit Court. In February 2025, the D.C. Circuit Court granted an unopposed motion filed by the Department of Justice on behalf of the EPA, holding the litigation in abeyance for a period of 120 days while the new leadership at the EPA evaluates the rule and determines how it wishes to proceed.

MISO — In 2012, the Illinois Environmental Protection Agency (IEPA) issued violation notices alleging violations of groundwater standards onsite at our Baldwin and Vermilion facilities' CCR surface impoundments. These violation notices remain unresolved; however, in 2016, the IEPA approved our closure and post-closure care plans for the Baldwin old east, east, and west fly ash CCR surface impoundments. We have completed closure activities at those ponds at our Baldwin facility.

At our retired Vermilion facility, which was not potentially subject to the EPA's 2015 CCR rule until the aforementioned D.C. Circuit Court decision in August 2018, we submitted proposed corrective action plans involving closure of two CCR surface impoundments (*i.e.*, the old east and the north impoundments) to the IEPA in 2012, and we submitted revised plans in 2014. In May 2017, in response to a request from the IEPA for additional information regarding the closure of these Vermilion surface impoundments, we agreed to perform additional groundwater sampling and closure options and riverbank stabilizing options. In June 2018, the IEPA issued a violation notice for alleged seep discharges claimed to be coming from the surface impoundments at our retired Vermilion facility, which is owned by our subsidiary DMG, and that notice was referred to the Illinois Attorney General. In June 2021, the Illinois Attorney General and the Vermilion County State Attorney filed a complaint in Illinois state court with an agreed interim consent order which the court subsequently entered. Given the violation notices and the enforcement action, the unique characteristics of the site, and the proximity of the site to the only national scenic river in Illinois, we agreed to enter into the interim consent order to resolve this matter. Per the terms of the agreed interim consent order, DMG is required to evaluate the closure alternatives under the requirements of the Illinois Coal Ash regulation (discussed below) and close the site by removal. In addition, the interim consent order requires that during the impoundment closure process, impacted groundwater will be collected before it leaves the site or enters the nearby Vermilion river and, if necessary, DMG will be required to install temporary riverbank protection if the river migrates within a certain distance of the impoundments. The interim order was modified in December 2022 to require certain amendments to the Safety Emergency Response Plan. In June 2023, the Illinois state court approved and entered the final consent order, which included the terms above and a requirement that when IEPA issues a final closure permit for the site, DMG will demolish the power station and submit for approval to construct an on-site landfill within the footprint of the former plant to store and manage the coal ash. These proposed closure costs are reflected in the ARO in the consolidated balance sheets (see Note 13 to the Financial Statements).

In 2012, the IEPA issued violation notices alleging violations of groundwater standards at the Newton and Coffeen facilities' CCR surface impoundments. We are addressing these CCR surface impoundments in accordance with the federal CCR rule.

In July 2019, coal ash disposal and storage legislation in Illinois was enacted. The legislation addresses state requirements for the proper closure of coal ash ponds in the state of Illinois. The law tasks the IEPA and the IPCB to set up a series of guidelines, rules, and permit requirements for closure of ash ponds. Under the final rule, which was finalized and became effective in April 2021, coal ash impoundment owners would be required to submit a closure alternative analysis to the IEPA for the selection of the best method for coal ash remediation at a particular site. The rule does not mandate closure by removal at any site. In May 2021, we, along with other industry petitioners, filed an appeal in the Illinois Fourth Judicial District over certain provisions of the final rule. In March 2024, the Illinois Fourth Judicial District issued a decision denying the industry petitions. We do not anticipate any impacts from this decision. In October 2021, we filed operating permit applications for 18 impoundments as required by the Illinois coal ash rule, and filed construction permit applications for three of our sites in January 2022 and five of our sites in July 2022. One additional closure construction application was filed for our Baldwin facility in August 2023.

For all of the above CCR matters, if certain corrective action measures, including groundwater treatment or removal of ash, are required at any of our coal-fueled facilities, we may incur significant costs that could have a material adverse effect on our financial condition, results of operations, and cash flows. The Illinois coal ash rule was finalized in April 2021 and does not require removal. However, the rule required us to undertake further site-specific evaluations required by each program. We will not know the full range of decommissioning costs, including groundwater remediation, if any, that ultimately may be required under the Illinois rule until permit applications have been approved by the IEPA and as such, an estimate of such costs cannot be made. The CCR surface impoundment and landfill closure costs currently reflected in our existing ARO liabilities reflect the costs of closure methods that our operations and environmental services teams determined were appropriate based on the existing closure requirements at the time we recorded those ARO liabilities, and is reasonably possible for those to increase once the IEPA determines final closure requirements. Once the IEPA acts on our permit applications, we will reassess the decommissioning costs and adjust our ARO liabilities accordingly.

Water

The EPA and the environmental regulatory bodies of states in which we operate have jurisdiction over the diversion, impoundment and withdrawal of water for cooling and other purposes and the discharge of wastewater (including storm water) from our facilities. We believe our facilities are presently in material compliance with applicable federal and state requirements relating to these activities. We believe we hold all required permits relating to these activities for facilities in operation and have applied for or obtained necessary permits for facilities under construction. We also believe we can satisfy the requirements necessary to obtain any required permits or renewals.

Effluent Limitation Guidelines (ELGs) — In November 2015, the EPA revised the ELGs for steam electricity generation facilities, which will impose more stringent standards (as individual permits are renewed) for wastewater streams, such as FGD, fly ash, bottom ash, and flue gas mercury control wastewaters. Various parties filed petitions for review of the ELG rule, and the petitions were consolidated in the Fifth Circuit Court. In April 2017, the EPA granted petitions requesting reconsideration of the ELG rule and administratively stayed the rule's compliance date deadlines. In April 2019, the Fifth Circuit Court vacated and remanded portions of the EPA's ELG rule pertaining to effluent limitations for legacy wastewater and leachate. The EPA published a final rule in October 2020 that extends the compliance date for both FGD and bottom ash transport water to no later than December 2025, as negotiated with the state permitting agency. Additionally, the final rule allows for a retirement exemption that exempts facilities certifying that units will retire by December 2028 provided certain effluent limitations are met. In November 2020, environmental groups petitioned for review of the new ELG revisions, and Vistra subsidiaries filed a motion to intervene in support of the EPA in December 2020. Notifications were made to Texas, Illinois, and Ohio state agencies on the retirement exemption for applicable coal plants by the regulatory deadline of October 13, 2021. In May 2024, the EPA published the final ELG rule revisions, which contain new requirements for legacy wastewater and combustion residual leachate. The final rule also leaves in place the subcategory for facilities that permanently cease coal combustion by 2028. We are reviewing the rule for impact but believe it will require additional treatment costs for legacy wastewaters during pond closure activities and combustion residual leachate. At this time, we don't expect the impact of these additional treatment costs to be material. A number of parties have since challenged the rule and that case is pending in the U.S. Court of Appeals for the Eighth Circuit. We are not a party to that litigation. In February 2025, the Department of Justice on behalf of the EPA filed an unopposed motion seeking to hold the litigation in abeyance while the new leadership at the EPA evaluates the rule and determines how it wishes to proceed.

Radioactive Waste

The nuclear industry has developed ways to store used nuclear fuel on site at nuclear generation facilities, primarily using dry cask storage, since there are no facilities for reprocessing or disposal of used nuclear fuel currently in operation in the U.S. Luminant stores its used nuclear fuel on-site in storage pools or dry cask storage facilities and believes its on-site used nuclear fuel storage capability is sufficient for the foreseeable future.

Corporate Information

Vistra is a Delaware corporation whose common stock is listed and traded on the NYSE. Our principal executive office is located at 6555 Sierra Drive, Irving, Texas 75039. The telephone number for our principal executive office is (214) 812-4600. We maintain a website located at *www.vistracorp.com*.

Available Information

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports with the SEC. You may obtain copies of these documents, free of charge, on the SEC's website at *www.sec.gov* or on Vistra's website at *www.vistracorp.com*, as soon as reasonably practicable after they have been filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. Vistra also posts important information, including press releases, investor presentations, sustainability reports, and notices of upcoming events on its website and utilizes its website as a channel of distribution to reach public investors and as a means of disclosing material non-public information for complying with disclosure obligations under Regulation FD. Investors may be notified of postings to our website by signing up for email alerts and RSS feeds on the "Investor Relations" page. The information on Vistra's website shall not be deemed a part of, or incorporated by reference into, this annual report on Form 10-K.

Item 1A. RISK FACTORS

Summary of Risk Factors

The following summarizes the principal factors that make an investment in our company speculative or risky, all of which are more fully described in the Risk Factors section below. This summary should be read in conjunction with the Risk Factors section and should not be relied upon as an exhaustive summary of the material risks facing our business. The following factors could result in harm to our business, financial condition, results of operations, cash flows, and prospects, among other impacts:

Market, Financial, and Economic Risks

- Our revenues, results of operations, and operating cash flows are affected by price fluctuations in the wholesale power market and other market factors beyond our control.
- We purchase natural gas, coal, fuel oil, and nuclear fuel for our generation facilities, and higher than expected fuel costs or disruptions in these fuel markets may have an adverse impact on, our costs, revenues, results of operations, financial condition, and cash flows.
- We have retired, announced planned retirements of, and may be forced to retire or idle additional underperforming generation units which could result in significant costs and have an adverse effect on our operating results.
- Our assets or positions cannot be fully hedged against changes in commodity prices and Market Heat Rates, and hedging transactions may not work as planned or hedge counterparties may default on their obligations.
- Competition, changes in market structure, and/or state or federal interference in the wholesale and retail power markets, together with subsidized generation, may have a material adverse effect on our financial condition, results of operations, and cash flows.
- Our results of operations and financial condition could be materially and adversely affected by energy market participants continuing to construct new generation facilities or expanding or enhancing existing generation facilities despite relatively low power prices and such additional generation capacity results in a reduction in wholesale power prices.
- Our liquidity needs could be difficult to satisfy, particularly during times of uncertainty in the financial markets or during times of significant fluctuation in commodity prices, and we may be unable to access capital on favorable terms or at all in the future, which could have a material adverse effect on us.
- The agreements and instruments governing our debt, including the Vistra Operations Credit Facilities and indentures, contain restrictions and limitations that could affect our ability to operate our business, our liquidity, and our results of operations, and any failure to comply with these restrictions could have a material adverse effect on us.
- We may not be able to complete future acquisitions on favorable terms or at all, successfully integrate future acquisitions into our business, or effectively identify and invest in value-creating businesses, assets or projects, which could result in unanticipated expenses and losses or otherwise hinder or delay our growth strategy.
- Our ability to achieve the expected growth of our Vistra Zero portfolio, consisting of our solar generation, battery ESS, and other renewables development projects, is subject to substantial capital requirements and other significant uncertainties.
- Tax legislation initiatives or challenges to our tax positions, or potential future legislation or the imposition of new or increased taxes or fees, could have a material adverse effect on our financial condition, results of operations, and cash flows.
- If electricity demand does not grow at the rate expected, or if we are unable to execute on large load offtake opportunities, our financial performance, growth opportunities, and stock price could be adversely impacted.

Regulatory and Legislative Risks

- Our businesses are subject to ongoing complex governmental regulations and legislation that have adversely impacted, and may in the future adversely impact, our businesses, results of operations, liquidity and financial condition.

- Our cost of compliance with existing and new environmental laws could have a material adverse effect on us.
- Pending or proposed laws or regulations, or the repeal of existing beneficial laws or regulations, including those proposed or implemented under the Trump administration, could have a material adverse effect on our businesses, results of operations, liquidity and financial condition.
- Changes to laws, rules or regulations related to market structures in the markets in which we participate may have a material adverse effect on our businesses, results of operation, liquidity and financial condition.
- We could be materially and adversely affected if current regulations are implemented or if new federal or state legislation or regulations are adopted to address global climate change, or if we are subject to lawsuits for alleged damage to persons or property resulting from greenhouse gas emissions.
- Litigation, legal proceedings, regulatory investigations or other administrative proceedings could expose us to significant liabilities and reputational damage that could have a material adverse effect on us.

Operational Risks

- Volatile power supply costs and demand for power have and could in the future adversely affect the financial performance of our retail businesses.
- Our retail operations are subject to significant competition from other REPs, which could result in a loss of existing customers and the inability to attract new customers.
- Cybersecurity attacks or technology systems failures could disrupt business operations and expose us to significant liabilities, reputational damage, loss of customers, and regulatory action.
- The operation of our businesses is subject to information security and operational technology risks, including cybersecurity breaches and failure of critical information and operations technology systems. Attacks on our infrastructure that breach cyber/data security measures could expose us to significant liabilities, reputational damage, regulatory action, and disrupt business operations, which could have a material adverse effect on us.
- We may suffer material losses, costs and liabilities due to operational risks, regulatory risks, and the risk of nuclear accidents arising from the ownership and operation of the nuclear generation facilities.
- The operation and maintenance of power generation facilities and related mining operations are capital intensive and involve significant risks that could adversely affect our results of operations, liquidity and financial condition.
- We may be materially and adversely affected by obligations to comply with federal and state regulations, laws, and other legal requirements that govern the operations, assessments, storage, closure, corrective action, disposal and monitoring relating to CCR.
- We have been and may in the future be materially and adversely affected by the effects of extreme weather conditions and seasonality.
- Events outside of our control, including an epidemic or outbreak of an infectious disease may materially adversely affect our business.
- Changes in technology, increased electricity conservation efforts, or energy sustainability efforts may reduce the value of our business, introduce new or emerging risks and may otherwise have a material adverse effect on us.

Risks Related to Our Structure and Ownership of our Common Stock

- Evolving expectations from stakeholders, including investors, on ESG issues, including climate change and sustainability matters, and erosion of stakeholder trust or confidence could influence actions or decisions about our company and our industry and could adversely affect our business, operations, financial results, or stock price.
- We may not pay any dividends on our common stock in the future, and we may not realize the anticipated benefits of our share repurchase program.

Please carefully consider the following discussion of significant factors, events, and uncertainties that make an investment in our securities risky. These factors, in addition to others specifically addressed in Item 7. *Management's Discussion and Analysis of Financial Condition, and Results of Operations (MD&A)*, provide important information for the understanding of our forward-looking statements in this annual report on Form 10-K. If one or more of the factors, events and uncertainties discussed below or in the MD&A were to materialize, our business, results of operations, liquidity, financial condition, cash flows, reputation or prospects could be materially adversely affected. In addition, if one or more of such factors, events and uncertainties were to materialize, it could cause results or outcomes to differ materially from those contained in or implied by any forward-looking statement in this annual report on Form 10-K. There may be further risks and uncertainties that are not currently known or that are not currently believed to be material that may adversely affect our business, results of operations, liquidity, financial condition and prospects and the market price of our common stock in the future. The realization of any of these factors could cause investors in our securities (including our common stock) to lose all or a substantial portion of their investment.

Market, Financial and Economic Risks

Our revenues, results of operations and operating cash flows generally are affected by price fluctuations in the wholesale power market and other market factors beyond our control.

We are not guaranteed any rate of return on capital investments in our businesses. We conduct integrated power generation and retail electricity activities, focusing on power generation, wholesale electricity sales and purchases, retail sales of electricity and natural gas to end users and commodity risk management. Our wholesale and retail businesses are to some extent countercyclical in nature, particularly for the wholesale power and ancillary services supplied to the retail business. However, we do have a wholesale power position that is subject to wholesale power price moves, which may be significant. As a result, our revenues, results of operations and operating cash flows depend in large part upon wholesale market prices for electricity, natural gas, uranium, lignite, coal, fuel oil, and transportation in our regional markets and other competitive markets in which we operate and upon prevailing retail electricity rates, which may be impacted by, among other things, actions of regulatory authorities.

Market prices for power, capacity, ancillary services, natural gas, coal and fuel oil are unpredictable and may fluctuate substantially over relatively short periods of time. Unlike most other commodities, electric power can only be stored on a very limited basis and generally must be produced concurrently with its use. As a result, power prices are subject to significant volatility due to supply and demand imbalances, especially in the day-ahead and spot markets. Demand for electricity can fluctuate dramatically, creating periods of substantial under- or over-supply. Over-supply can occur as a result of the construction of new power generation sources. During periods of over-supply, electricity prices might be depressed. For example, in many instances, energy from renewable resources, such as solar, wind and battery ESS, are bid into the relevant spot market at a price of zero or close to zero during certain times of the day, lowering the clearing price for all power wholesalers in such market. Also, at times there is political pressure, or pressure from regulatory authorities with jurisdiction over wholesale and retail energy commodity and transportation rates, to impose price limitations, bidding rules and other mechanisms to address volatility and other issues in these markets.

Extreme weather events can also materially impact power prices or otherwise exacerbate conditions or circumstances that result in volatility of power prices. For example, in February 2021, the U.S. experienced Winter Storm Uri and extreme cold temperatures in the central U.S., including Texas. This severe weather event substantially increased the demand for natural gas used in our electric power generation business, and the cold further limited the availability of renewable generation across the region contributing to extremely high market prices for natural gas and electricity, which resulted in substantial increases in the costs to procure sufficient fuel supply and increased collateral posting requirements. Winter Storm Elliott, in December 2022, and Winter Storm Heather, in January 2024, were other examples of extreme weather across the U.S. that resulted in widespread wholesale power market volatility.

The majority of our facilities operate as "merchant" facilities without long-term power sales agreements. As a result, we largely sell electric energy, capacity and ancillary services into the wholesale energy spot market or into other wholesale and retail power markets on a short-term basis and are not guaranteed any rate of return on our capital investments. Consequently, there can be no assurance that we will be able to sell any or all of the electric energy, capacity or ancillary services from those facilities at commercially attractive rates or that our facilities will be able to operate profitably. We depend, in large part, upon prevailing market prices for power, capacity and fuel. Given the volatility of commodity power prices, to the extent we are unable to hedge or otherwise secure long-term power sales agreements for the output of our power generation facilities, our revenues and profitability will be subject to volatility, and our financial condition, results of operations and cash flows could be materially adversely affected.

We purchase natural gas, coal, fuel oil, and nuclear fuel for our generation facilities, and higher than expected fuel costs, volatility, or disruption in these fuel markets may have an adverse impact on our costs, revenues, results of operations, financial condition and cash flows.

We rely on natural gas, coal, fuel oil, and nuclear fuel for the majority of our power generation facilities. Delivery of these fuels to the facilities is dependent upon the continuing availability of such fuels and financial viability of contractual counterparties as well as upon the infrastructure (including mines, rail lines, rail cars, barge facilities, roadways, riverways and natural gas pipelines) available and functioning to serve each generation facility, and geopolitical risk, including the current Russia and Ukraine conflict and the potential for additional U.S. sanctions against Russia or other potential restrictions on Russian energy deliveries. See Item 7. *Management's Discussion and Analysis of Financial Condition, and Results of Operations – Significant Activities and Events, and Items Influencing Future Performance - Macroeconomic Conditions*. As a result, we have experienced, and remain subject to the risks of disruptions or curtailments in the production of power at our generation facilities if no fuel is available at any price, if a counterparty fails to perform or if there is a disruption in the fuel delivery infrastructure. Certain of our generation facilities rely on a limited number of counterparties, such as natural gas suppliers and railcar companies, to provide the necessary fuel. Disputes relating to or non-performance of contractual arrangements have resulted in, and may continue to result in adverse impacts to our costs, revenues, results of operations, financial condition, and cash flows.

As part of our strategy to mitigate the potential negative effects of commodity price volatility, we have sold forward a substantial portion of our expected power sales in the next few years in order to lock in long-term prices. In order to hedge our obligations under these forward power sales contracts, we have entered into long-term and short-term contracts for the purchase and delivery of fuel. Many of the forward power sales contracts do not allow us to pass through changes in fuel costs or discharge the power sale obligations in the case of a disruption in fuel supply due to force majeure events or the default of a fuel supplier or transporter. Fuel costs (including diesel, natural gas, lignite, coal and nuclear fuel) are volatile, and the wholesale price for power does not always change at the same rate as changes in fuel costs, and disruptions in our fuel supplies may therefore require us to find alternative fuel sources at costs which may be higher than planned, to find other sources of power to deliver to counterparties at a higher cost, or to pay damages to counterparties for failure to deliver power as contracted. Long-term and short-term contracts are subject to risk of non-delivery or claims of force majeure, which may impact our ability to economically recover the value of the contract. In addition, we purchase and sell natural gas and other energy related commodities, and volatility in these markets may affect costs incurred in meeting our obligations. Further, any changes in the costs of natural gas, coal, fuel oil, nuclear fuel or transportation rates and changes in the relationship between such costs and the market prices of power will affect our financial results. If we are unable to procure fuel for physical delivery at prices we consider favorable, or if we are unable to procure these fuels at all, our financial condition, results of operations and cash flows could be materially adversely affected. For example, supply challenges were among the primary drivers of the significant loss experienced in 2021 as a result of Winter Storm Uri.

We also buy significant quantities of fuel on a short-term or spot market basis. Prices for all of our fuels fluctuate, sometimes rising or falling significantly over a relatively short period of time. The price we can obtain for the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel or delivery costs. This may have a material adverse effect on our financial and operating performance. Volatility in market prices for fuel and power results from, among other factors:

- demand for energy commodities and general economic conditions, including impacts of inflation and the relative strength or weakness of U.S. dollar compared to other currencies;
- volatility in commodity prices and the supply of commodities, including but not limited to natural gas, coal and fuel oil;
- volatility in Market Heat Rates;
- volatility in coal and rail transportation prices;
- volatility in nuclear fuel and related enrichment and conversion services;
- transmission or transportation disruptions, constraints, congestion, inoperability or inefficiencies of electricity, natural gas or coal transmission or transportation, or other changes in power transmission infrastructure;
- severe, sustained or unexpected weather conditions, including extreme cold, drought and limitations on access to water;
- seasonality;
- changes in electricity and fuel usage resulting from conservation efforts, changes in technology or other factors;
- illiquidity in the wholesale power or other commodity markets;
- importation of liquified natural gas to certain markets;
- development and availability of new fuels, new technologies and new forms of competition for the production and storage of power, including competitively priced alternative energy sources or storage;

- changes in market structure and liquidity;
- changes in the way we operate our facilities, including curtailed operation due to market pricing, environmental regulations and legislation, safety or other factors;
- changes in generation capacity or efficiency;
- outages or otherwise reduced output from our generation facilities or those of our competitors;
- changes in electric capacity, including the addition of new supplies of power as a result of the development of new plants, expansion of existing plants, the continued operation of uneconomic power plants due to federal, state or local subsidies, or additional transmission capacity;
- local, regional, national, or global supply chain constraints or shortages;
- our creditworthiness and liquidity and the willingness of fuel suppliers and transporters to do business with us;
- changes in the credit risk, payment practices, or financial condition of market participants;
- changes in production and storage levels of natural gas, lignite, coal, uranium, diesel and other refined products;
- pandemics and epidemics (including the impacts thereto, or recovery therefrom), natural disasters, wars, sabotage, terrorist acts, embargoes and other catastrophic events; and
- changes in law, including judicial decisions, federal, state and local energy, environmental and other regulation and legislation.

See "*Economic downturns would likely have a material adverse effect on our businesses"* for a discussion of potential risks arising from current U.S. and global economic and geopolitical conditions.

We have retired, announced planned retirements of, and may be forced to retire or idle additional underperforming generation units which could result in significant costs and have an adverse effect on our operating results.

A sustained decrease in the financial results from, or the value of, our generation units has resulted in the retirement or planned retirement of, and ultimately could result in additional retirements or idling of, generation units. We have operated certain of our lignite- and coal-fueled generation assets only during parts of the year that have higher electricity demand and, therefore, higher related wholesale electricity prices. In connection with the closure and remediation of retired generation units, we have spent, and may in the future spend, a significant amount of money, internal resources and time to complete the required closure and reclamation, which could have a material adverse effect on our financial and operating performance.

Our assets or positions cannot be fully hedged against changes in commodity prices and Market Heat Rates, and hedging transactions may not work as planned, or counterparties may default on their obligations, which could have a material adverse impact on our business, financial condition, results of operations and cash flows.

Our hedging activities do not fully protect us against the risks associated with changes in commodity prices, most notably electricity and natural gas prices, because of the expected useful life of our generation assets and the size of our position relative to the duration of available markets for various hedging activities. Generally, commodity markets that we participate in to hedge our exposure to electricity prices and Market Heat Rates have limited liquidity after two to three years. Further, our ability to hedge our revenues by utilizing cross-commodity hedging strategies with natural gas hedging instruments is generally limited to a duration of four to five years. To the extent we have unhedged positions, fluctuating commodity prices and/or Market Heat Rates can materially impact our results of operations, cash flows, liquidity and financial condition, either favorably or unfavorably.

To manage our financial exposure related to commodity price fluctuations, we routinely enter into contracts to hedge portions of purchase and sale commitments, fuel requirements and inventories of natural gas, lignite, coal, diesel fuel, uranium and refined products, and other commodities, within established risk management guidelines. As part of this strategy, we routinely utilize fixed-price forward physical purchase and sale contracts, futures, financial swaps and option contracts traded in over-the-counter markets or on exchanges. Given our exposure to risks of commodity price movements, we devote a considerable amount of time and effort to the establishment of risk management policies and procedures, as well as the ongoing review of the implementation of these policies and procedures. Additionally, we have processes and controls in place that are designed to monitor and accurately report hedging activities and positions. The policies, procedures, processes and controls in place may not always function as planned and cannot eliminate all the risks associated with these activities, including unauthorized hedging activity, or improper reporting thereof, by our employees in violation of our existing risk management policies and procedures. For example, we hedge the expected needs of our wholesale and retail customers, but unexpected changes due to weather, natural disasters, consumer behavior, market constraints or other factors could cause us to purchase electricity to meet unexpected demand in periods of high wholesale market prices or resell excess electricity into the wholesale market in periods of low prices. As a result of these and other factors, the impacts of our commodity hedging activities and risk management decisions may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Based on economic and other considerations, including our available liquidity, we may not be able to, or we may decide not to, hedge the entire exposure of our operations to commodity price risk. To the extent we do not hedge against commodity price risk and applicable commodity prices change in ways adverse to us, we could be materially and adversely affected. To the extent we do hedge against commodity price risk, those hedges may ultimately prove to be ineffective. Additionally, there may be changes to existing laws or regulations that could significantly impact our ability to effectively hedge, which may have a material adverse effect on us.

To the extent we engage in hedging and risk management, and power purchase agreement activities, we are exposed to the credit risk that counterparties that owe us money, energy or other commodities as a result of these activities will not perform their obligations to us. Should the counterparties to these arrangements fail to perform, we could be forced to enter into alternative hedging arrangements or honor the underlying commitment at then-current market prices. Additionally, our counterparties may seek bankruptcy protection under Chapter 11 or liquidation under Chapter 7 of the U.S. Bankruptcy Code. Our credit risk may be exacerbated to the extent collateral held by us cannot be realized or is liquidated at prices not sufficient to recover the full amount due to us. There can be no assurance that any such losses or impairments to the carrying value of our financial assets would not materially and adversely affect our financial condition, results of operations and cash flows. In such event, we could incur losses or forgo expected gains in addition to amounts, if any, already paid to the counterparties. Market participants in the ISOs/RTOs in which we operate are also exposed to risks that another market participant may default on its obligations to pay such ISO/RTO for electricity or services taken, in which case such costs, to the extent not offset by posted security and other protections available to such ISO/RTO, may be allocated to various non-defaulting ISO/RTO market participants, including us.

We do not apply hedge accounting to our commodity derivative transactions, which may cause increased volatility in our quarterly and annual financial results.

We enter derivative instruments to manage commodity price risks. All our derivatives are accounted for as economic hedges and are recorded at estimated fair value in the consolidated balance sheets with changes in fair value recorded as gains or losses in the earnings of the period in which they occur. No derivative positions are accounted for as cash flow or fair value hedges.

A derivative contract may be designated as a normal purchase or sale if the commodity is to be physically received or delivered for use or sale in the normal course of business. If designated as normal, the derivative contract is accounted for under the accrual method of accounting (not marked-to-market) with no balance sheet or income statement recognition of the contract until settlement. While certain retail sales contract portfolios are designated as normal, the majority of our derivative positions are subject to adjustments caused by changes in forward commodity prices. As a result, our quarterly and annual financial results, prepared in accordance with GAAP, are subject to increased volatility.

Competition, changes in market structure, and/or state or federal interference in the wholesale and retail power markets, together with subsidized generation, may have a material adverse effect on our financial condition, results of operations and cash flows.

Our generation and competitive retail businesses rely on a competitive wholesale marketplace. The competitive wholesale marketplace may be undermined by changes in market structure and out-of-market subsidies provided by federal or state entities, including bailouts of uneconomic plants, imports of power from Canada, renewable mandates or subsidies, as well as out-of-market payments to new generators. Multiple potential changes have been and are being evaluated by the PUCT and the Texas Legislature for the ERCOT market, including Dispatchable Reliability Reserve Service that would facilitate compliance with a required reliability standard, the ultimate resolution of which is unknown. In another example, the resolution of a number of filings pending at FERC could impact PJM capacity market rules in future years.

Our power generation business competes with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities, other energy service companies and financial institutions in the sale of electric energy, capacity and ancillary services, as well as in the procurement of fuel, transmission and transportation services. Moreover, aggregate demand for power may be met by generation capacity based on several competing technologies, as well as power generation facilities fueled by alternative or renewable energy sources, including hydroelectric power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. Regulatory initiatives designed to enhance and/or subsidize renewable generation increases competition from these types of facilities and out-of-market subsidies to existing or new generation can undermine the competitive wholesale marketplace, which can lead to premature retirement of existing facilities, including those owned by us.

We also compete against other energy merchants on the basis of our relative operating skills, financial position and access to credit sources. Electric energy customers, wholesale energy suppliers and transporters often seek financial guarantees, credit support such as letters of credit and other assurances that their energy contracts will be satisfied. Companies with which we compete may have greater resources or experience in these areas. Over time, some of our plants may become unable to compete because of subsidized generation, including public utility commission supported power purchase agreements, and the construction of new plants. Such new plants could have a number of advantages including more efficient equipment and newer technology that could result in fewer emissions or more advantageous locations on the electric transmission system. Additionally, these competitors may be able to respond more quickly to new laws and regulations because of the newer technology utilized in their facilities or the additional resources derived from owning more efficient facilities.

Other factors may contribute to increased competition in wholesale power markets. We expect that we will continue to face intense competition from numerous companies, including new entrants or consolidation of existing competitors, in the industry. Certain federal and state entities in jurisdictions in which we operate have either enacted or are considering regulations or legislation to subsidize otherwise uneconomic plants and attempt to incentivize, including through certain tax benefits, the construction and development of additional renewable resources as well as increases in energy efficiency investments. For example, the Inflation Reduction Act of 2022 contains a number of tax credits and incentives relating to renewable projects and clean energy technologies such as nuclear energy. New entrants or existing competitors may find it more economical to develop new renewable projects or invest in clean energy technologies in which we would like to invest. Subsidies (or increases thereto) to our competitors could result in increased competition for us, which could have a material adverse effect on our financial condition, results of operations and cash flows.

In addition, our retail marketing efforts compete for customers in a competitive environment, which impacts the margins that we can earn on the volumes we are able to serve. Further, with retail competition, it is easier for residential customers where we serve load to switch competitive electricity generation suppliers for their energy needs. The volatility and uncertainty that results from such mobility may have material adverse effects on our financial condition, results of operations and cash flows. For example, if fewer customers switch to another supplier than anticipated, the load we must serve will be greater than anticipated, and if market prices of fuel have increased, our costs will increase more than expected due to the need to go to the market to cover the incremental supply obligation. If more customers switch to another supplier than anticipated, the load we must serve will be lower than anticipated and, if market prices of electricity have decreased, our operating results could suffer.

Our results of operations and financial condition could be materially and adversely affected by energy market participants continuing to construct new generation facilities or expanding or enhancing existing generation facilities despite relatively low power prices and such additional generation capacity results in a reduction in wholesale power prices.

Given the overall attractiveness of certain markets in which we operate and certain tax benefits associated with renewable energy, among other matters, energy market participants have continued to construct new generation facilities or invest in enhancements or expansions of existing generation facilities despite relatively low wholesale power prices. Assuming this market dynamic continues, our results of operations and financial condition could be materially and adversely affected if such additional generation capacity results in an over-supply of electricity that causes a reduction in wholesale power prices. Additionally, new or existing market participants without, or with less, fossil fuel operations may gain additional market share, or reduce our market share, due to evolving expectations and sentiments of key stakeholders, government, and regulatory authorities regarding our operations and activities.

Economic downturns would likely have a material adverse effect on our businesses.

Our results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including lower prices for power, generation capacity and natural gas, which can fluctuate substantially. Increased unemployment of residential customers and decreased demand for products and services by commercial and industrial customers resulting from an economic downturn could lead to declines in the demand for energy and an increase in the number of uncollectible customer balances, which would negatively impact our overall sales and cash flows. The convergence of current global conditions, including sustained inflation, elevated interest rates, and the geopolitical climate, has and could lead to, or accelerate or exacerbate the occurrence of, a significant economic downturn, as well as changes in consumer and counterparty behavior, higher costs of capital, decreases in the value of our existing long-dated contracts, commodity price increases and volatility, supply chain shortages, and other adverse impacts to our business. For example, the U.S. administration has taken action or may take action in the future with respect to major changes to trade policies, such as the imposition of tariffs on imported products and the withdrawal from or renegotiation of certain trade agreements. Any such material changes in trade policies, including the imposition of tariffs, could lead to increased supply chain disruptions and increased supply chain costs, which could have a material adverse impact on our business, financial condition and results of operations.

Our liquidity needs could be difficult to satisfy, particularly during times of uncertainty in the financial markets or during times of significant fluctuation in commodity prices, and we may be unable to access capital on favorable terms or at all in the future, which could have a material adverse effect on us. Vistra currently maintains non-investment grade credit ratings that could negatively affect our ability to access capital on favorable terms or result in higher collateral requirements, particularly if our credit ratings were to be downgraded in the future.

Our businesses are capital intensive. In general, we rely on access to financial markets and credit facilities as a significant source of liquidity for our capital requirements, hedging transactions and other obligations not satisfied by cash-on-hand or operating cash flows. The inability to raise capital or to access credit facilities, particularly on favorable terms, could adversely impact our liquidity and our ability to meet our obligations or sustain and grow our businesses and could increase capital costs and collateral requirements, any of which could have a material adverse effect on us.

Our access to capital and the cost and other terms of acquiring capital are dependent upon, and could be adversely impacted by, various factors, including:

- general economic and capital markets conditions, including changes in financial markets that reduce available liquidity or the ability to obtain or renew credit facilities on favorable terms or at all;
- conditions and economic weakness in the U.S. power markets;
- regulatory developments;
- changes in interest rates;
- a deterioration, or perceived deterioration, of our creditworthiness, enterprise value or financial or operating results;
- a downgrade of Vistra's or its applicable subsidiaries' credit ratings, or credit ratings of its issuances;
- our level of indebtedness and compliance with covenants in our debt agreements;
- our ability to meet our sustainability targets in our secured credit facilities;
- a deterioration of the creditworthiness or bankruptcy of one or more lenders or counterparties under our credit facilities that affects the ability of such lender(s) to make loans to us;
- credit, security, or collateral requirements, including those relating to volatility in commodity prices;
- general credit availability from banks or other lenders for us and our industry peers;
- investor and lender confidence in and sentiment of the industry, our business, and the wholesale electricity markets in which we operate;

- a material breakdown in or oversight in effectuating our risk management procedures;
- the occurrence of changes in our businesses;
- disruptions, constraints, or inefficiencies in the continued reliable operation of our generation facilities and battery ESS; and
- changes in or the operation of provisions of tax and regulatory laws.

There are also increasing financial risks for companies that own and operate fossil fuel generation as institutional lenders or other sources of capital have become more attentive to sustainable financing practices and some of them may seek commitments on emission reduction targets or expected use or proceeds when providing funding to, or decline to provide funding for companies who produce or utilize fossil fuel energy or that have higher levels of GHG emissions. Our Vistra Operations Credit Agreement contains Sustainability Adjustments. These adjustments use baseline values from KPI Metrics and provide for decreases in the applicable credit spread adjustments and commitment fee rates if our reported metrics are a certain percentage below the baseline values, adjusted on a year-to-year basis. Conversely, if our reported metrics are a certain percentage above the baseline values, adjusted on a year-to-year basis, the applicable credit spread adjustments and fee rates are increased. Building in these adjustments to our credit agreement helps to show lenders we are committed to lowering our GHG emissions, but failing to meet the targets on a regular basis could be viewed negatively by such lenders. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists and others concerned about climate change not to provide funding for companies in the broader energy sector. Limitations on our access to, or increases in our cost of, capital could have a material adverse effect on us.

In addition, Vistra currently maintains non-investment grade credit ratings. As a result, we may not be able to access capital on terms (financial or otherwise) as favorable as companies that maintain investment-grade credit ratings or we may be unable to access capital at all at times when the credit markets tighten. In addition, due to our non-investment grade credit ratings, counterparties request collateral support (including cash or letters of credit) in order to enter into certain transactions with us.

A downgrade in long-term debt ratings generally causes borrowing costs to increase and the potential pool of investors to shrink and could trigger liquidity demands pursuant to contractual arrangements. Future transactions by Vistra or any of its subsidiaries, including the issuance of additional debt, could result in a temporary or permanent downgrade in our credit ratings.

Our indebtedness could adversely affect our ability in the future to raise additional capital to fund our operations. It could also expose us to the risk of increased interest rates and limit our ability to react to changes in the economy, or our industry, as well as impact our cash available for distribution.

As of December 31, 2024, we had approximately $18.4 billion of total indebtedness and approximately $17.2 billion of indebtedness net of cash. Our debt could have negative consequences for our financial condition including:

- increasing our vulnerability to general economic and industry conditions;
- requiring a significant portion of our cash flows from operations to be dedicated to the payment of principal and interest on our indebtedness, therefore reducing our ability to pay dividends to holders of our common stock or to fund our operations, capital expenditures and future business opportunities;
- limiting our ability to enter into long-term power sales or fuel purchases which require credit support;
- limiting our ability to fund operations or future acquisitions;
- limiting our ability to repurchase shares under the share repurchase program;
- restricting our ability to make distributions or pay dividends with respect to our common and preferred stock and the ability of our subsidiaries to make distributions to us, in light of restricted payment and other financial covenants in our credit facilities and other financing agreements;
- inhibiting the growth of our stock price;
- exposing us to the risk of increased interest rates because certain of our borrowings, including borrowings under the Vistra Operations Credit Facilities, are at variable rates of interest, only a portion of which are hedged;
- limiting our ability to obtain additional financing for working capital including collateral postings, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; and
- limiting our ability to adjust to changing market conditions and placing us at a competitive disadvantage compared to our competitors who may have less debt.

We may not be successful in obtaining additional capital for these or other reasons. Furthermore, we may be unable to refinance or replace our existing indebtedness on favorable terms or at all upon the expiration or termination thereof. Our failure to obtain additional capital or enter into new or replacement financing arrangements when due may constitute a default under such existing indebtedness and may have a material adverse effect on our business, financial condition, results of operations and cash flows.

The agreements and instruments governing our debt, including the Vistra Operations Credit Facilities and indentures, contain restrictions and limitations that could affect our ability to operate our business, or liquidity, and results of operations, and any failure to comply with these restrictions could have a material adverse effect on us.

The agreements and instruments governing our debt, including the Vistra Operations Credit Facilities and indentures, contain restrictions that could adversely affect us by limiting our ability to operate our businesses and plan for, or react to, market conditions or to meet our capital needs and could result in an event of default under the Vistra Operations Credit Facilities, indentures and/or our other debt facilities. The Vistra Operations Credit Facilities, indentures and our other debt facilities contain events of default customary for financings of such type. If we fail to comply with the covenants in the Vistra Operations Credit Facilities, indentures and/or our other debt facilities and are unable to obtain a waiver or amendment, or a default exists and is continuing, the lenders under such agreements or notes, as the case may be, could give notice and declare outstanding borrowings thereunder immediately due and payable. The breach of any covenants or obligations in certain agreements and instruments governing our debt, including the Vistra Operations Credit Facilities and indentures, not otherwise waived or amended, could result in a default under the applicable debt obligations and could trigger acceleration of those obligations, which in turn could trigger cross defaults under other agreements governing our debt, and any such acceleration of outstanding borrowings could have a material adverse effect on us.

Certain obligations are required to be secured by letters of credit, surety bonds, first liens, or cash, which increase our costs. If we are unable to provide such security, it may restrict our ability to conduct our business, which could have a material adverse effect on us.

We undertake certain hedging and commodity activities and enter certain financing arrangements with various counterparties that require cash collateral or the posting of letters of credit which are at risk of being drawn down in the event we default on our obligations. We currently use margin deposits, prepayments, surety bonds, letters of credit and first liens as credit support for commodity procurement and risk management activities. Future cash collateral requirements may increase based on the extent of our involvement in standard contracts and movements in commodity prices, the use of first lien collateral, and also based on our credit ratings and the general perception of creditworthiness in the markets in which we operate. In the case of commodity arrangements, the amount of such credit support that must be provided is typically based on the difference between the price of the commodity in a given contract and the market price of the commodity. Significant movements in market prices can result in our being required to provide cash collateral and letters of credit in very large amounts. The effectiveness of our strategy may be dependent on the amount of collateral available to enter into or maintain these contracts, and liquidity requirements may be greater than we anticipate or will be able to meet. Without enough working capital or other sources of available liquidity to post as collateral, we may not be able to manage price volatility effectively or to implement our strategy. A material increase in the amount of letters of credit or cash collateral required to be provided to our counterparties may have a material adverse effect on us.

We may not be able to complete future acquisitions on favorable terms or at all, successfully integrate future acquisitions into our business, or effectively identify and invest in value-creating businesses, assets or projects, which could result in unanticipated expenses and losses or otherwise hinder or delay our growth strategy.

As part of our growth strategy, including our desire to grow our retail platform, we may pursue acquisitions of assets or operating entities. This strategy depends on the Company's ability to successfully identify and evaluate acquisition opportunities and consummate acquisitions on favorable terms. Our ability to continue to implement this component of our growth strategy will be limited by our ability to identify appropriate acquisition or joint venture candidates and our financial resources, including available cash and access to capital. In addition, the Company will compete with other companies for these limited acquisition opportunities, which may increase the Company's cost of making acquisitions or limit the Company’s ability to make acquisitions at all. Any expense incurred in completing acquisitions or entering into joint ventures, the time it takes to integrate an acquisition or our failure to integrate acquired businesses successfully could result in unanticipated expenses and losses. Furthermore, we may not be able to fully realize the anticipated benefits from any future acquisitions or joint ventures we may pursue. In addition, the process of integrating acquired operations into our existing operations may involve unknown risks, result in unforeseen operating difficulties and expenses, and may require significant financial resources that would otherwise be available for the execution of our business strategy. If the Company is unable to identify and consummate future acquisitions, it may impede the Company's ability to execute its growth strategy.

Our ability to achieve the expected growth of our Vistra Zero portfolio, consisting of our solar generation, battery ESS, and other renewables development projects, is subject to substantial capital requirements and other significant uncertainties.

We have a substantial capital allocation plan intended for investments in renewable assets, including solar development projects and battery ESS. As part of our business strategy, we plan to continually assess potential strategic acquisitions or investments in renewable assets, emerging technologies and related projects. Notably, the Company's ability to successfully develop our current renewables projects, or in the future acquire additional renewable assets, may be impacted by the demand for and viability of renewable assets generally, which may vary depending on availability of projects and financing, as well as public policy, financial and tax mechanisms implemented at the state and federal levels to support the development of renewable assets. Various factors could result in increased costs or result in delays or cancellation of our current or future renewable projects, or the loss of, or declines in the value of, our investments in projects including, but not limited to, risks relating to siting, financing, engineering and construction, permitting, interconnection requests, federal and state regulatory approvals, new legislation or regulatory changes impacting the industry, commissioning delays, import tariffs, changes to federal income tax laws, economic events or factors, environmental and community concerns, availability of or requirements for additional funding, enhanced competition, or the potential for termination of the power sales contract as a result of a failure to meet certain milestones. Further, the recent proliferation of renewable projects has resulted in a large volume of interconnection requests submitted to grid operators, including the markets in which we operate, resulting in significant delays to the approval process and estimated completion dates for our projects and others. FERC and regional ISOs are working to address these backlogs, including with regulatory rule changes, changing the interconnection process, the impacts of which are currently unknown because the changes have only been partially implemented. Additionally, the increased demand for construction of renewables projects, such as battery ESS and solar projects, and other labor market and supply chain constraints have resulted, and may continue to result, in limited availability of qualified specialists, contractors, and necessary services or materials, leading to delays in and higher costs for the development and construction of our current and future planned projects. Should any of these factors occur, our financial position, results of operations, and cash flows could be adversely affected, or our future growth opportunities may not be realized as anticipated.

While certain of our subsidiaries are in various stages of developing and constructing solar generation facilities and battery ESS and certain of these projects have signed long-term contracts or made similar arrangements for the sale of electricity, in other cases, our subsidiaries may enter into obligations in the development process even though the subsidiaries have not yet secured power purchase arrangements or other important elements for a successful project. If the project does not proceed as planned, our subsidiaries may remain obligated for certain liabilities even though the project will not be completed. Development is inherently uncertain and we may forgo certain development opportunities and we may undertake significant development costs before determining that we will not proceed with a particular project. We believe that capitalized costs for projects under development are recoverable; however, there can be no assurance that any individual project will be completed and reach commercial operation. If these development efforts are not successful, we may abandon a project under development and write off the costs incurred in connection with such project and could incur additional losses associated with any related contingent liabilities.

Circumstances associated with potential divestitures could adversely affect our results of operations and financial condition.

In evaluating our business and the strategic fit of our various assets, we may determine to sell one or more of such assets. Despite a decision to divest an asset, we may encounter difficulty in finding a buyer willing to purchase the asset at an acceptable price and on acceptable terms and in a timely manner. In addition, a prospective buyer may have difficulty obtaining financing. Divestitures could involve additional risks, including:

- difficulties in the separation of operations and personnel;
- the need to provide significant ongoing post-closing transition support to a buyer;
- management's attention may be temporarily diverted;
- the retention of certain current or future liabilities in order to induce a buyer to complete a divestiture;
- the obligation to indemnify or reimburse a buyer for certain past liabilities of a divested asset;
- the disruption of our business; and
- potential loss of key employees.

We may not be successful in managing these or any other significant risks that we may encounter in divesting any asset, which could adversely affect our results of operations and financial condition.

If our goodwill, intangible assets, or long-lived assets become impaired, we may be required to record a significant charge to earnings.

Goodwill and intangible assets with indefinite useful lives, such as the intangible asset related to our retail trade names are not amortized and are subject to impairment testing annually, or when events or changes in the business environment indicate that the carrying value of the reporting unit may exceed its fair value. Additionally, we evaluate long-lived assets (including intangible assets with finite lives) for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Any reduction in or impairment of the value of goodwill, intangible assets, or other long-lived assets will result in a charge against earnings, which could materially adversely affect our reported results of operations and financial position in future periods.

If an impairment of goodwill, intangible assets with indefinite useful lives, or long-lived assets is realized, it may result in a significant charge to earnings in the respective quarterly or annual financial results prepared in accordance with GAAP.

Issuances or acquisitions of our common stock, or sales or dispositions of our common stock by stockholders, that result in an ownership change as defined in Internal Revenue Code (IRC) §382 could further limit our ability to use certain tax attributes and our federal net operating losses to offset our future taxable income.

If an "ownership change," as defined in Section 382 of the IRC (IRC §382) occurs, the amount of NOLs that could be used in any one year following such ownership change could be substantially limited. In general, an "ownership change" would occur when there is a greater than 50 percentage point increase in ownership of a company's stock by stockholders, each of which owns (or is deemed to own under IRC §382) 5 percent or more of such company's stock. Given IRC §382's broad definition, an ownership change could be the unintended consequence of otherwise normal market trading in our stock that is outside our control. Vistra acquired NOLs from its merger with Dynegy; however, Vistra's use of such attributes is limited under IRC §382 because the merger constituted an "ownership change" with respect to Dynegy. If there is an "ownership change" with respect to Vistra (including by the normal trading activity of greater than 5% stockholders), the utilization of all NOLs existing at that time would be subject to additional annual limitations based upon a formula provided under IRC §382 that is based on the fair market value of the Company and prevailing interest rates at the time of the ownership change. In addition, any ownership change with respect to Vistra could result in additional limitations on our ability to use certain tax attributes, including depreciation, existing at the time of any such ownership change and have an impact on our tax liabilities.

Tax legislation initiatives or challenges to our tax positions, or potential future legislation or the imposition of new or increased taxes or fees, could have a material adverse effect on our financial condition, results of operations and cash flows.

We are subject to the tax laws and regulations of the U.S. federal, state and local governments. From time to time, legislative measures may be enacted that could adversely affect our overall tax positions regarding income or other taxes. There can be no assurance that our effective tax rate or tax payments will not be adversely affected by these legislative measures. The Tax Cuts and Jobs Act of 2017 (TCJA), enacted December 22, 2017, and the Inflation Reduction Act (IRA), enacted August 16, 2022, both introduced significant changes to current U.S. federal tax law. For example, the IRA includes the enactment of several new proposals, including, but not limited to (i) a corporate alternative minimum tax based on book income and (ii) additional requirements to qualify for enhanced renewable energy tax credits. These changes are complex and continue to be the subject of additional guidance issued by the U.S. Treasury and the Internal Revenue Service. In addition, the reaction to the federal tax changes by the individual states continues to evolve. Our interpretations and assumptions around U.S. tax reform may evolve in future periods as further administrative guidance and regulations are issued, which may materially affect our effective tax rate or tax payments.

U.S. federal, state and local tax laws and regulations are extremely complex and subject to varying interpretations. There can be no assurance that our tax positions will be sustained if challenged by relevant tax authorities and if not sustained, there could be a material impact on our results of operations and financial condition.

U.S. federal income tax reform and changes in other tax laws could adversely affect us. Additionally, states in which we operate or own assets may impose new or increased taxes or fees on various aspects of our operations. The passage of any legislation as a result of these proposals and other similar changes in U.S. federal income tax laws or the imposition of new or increased taxes or fees could have a material adverse effect on our financial condition, results of operations and cash flows.

If electricity demand does not grow at the rate expected, or if we are unable to execute on large load offtake opportunities, our financial performance, growth opportunities, and stock price could be adversely impacted.

Multiple demand drivers such as emergence of large load data centers, including in response to transformations in technologies like artificial intelligence (AI) and electrification of oil field operations (specifically in the Permian Basin of west Texas), have accelerated, and are expected to continue to accelerate, load growth in the geographic regions we serve. We continue to pursue opportunities for the potential sale of power from our existing or new nuclear and gas facilities pursuant to long-term agreements to supply large load facilities. Such potential transactions are subject to certain risks and uncertainties, including various currently contemplated or future potential regulatory actions, reviews, and/or approvals and legislative actions, which could impact the timing of, and our ability to consummate, a potential transaction. In addition, if demand does not continue to increase at a rate in line with market expectations due to various factors, such as changes in technology, more energy efficient AI solutions or slow adoption of AI products and services, economic downturns, or adverse government actions, or if we are unable to execute on such large load offtake opportunities, our opportunities for growth and stock price may be adversely impacted.

Regulatory and Legislative Risks

Our businesses are subject to ongoing complex governmental regulations and legislation that have adversely impacted, and may in the future adversely impact, our businesses, results of operations, liquidity, financial condition, and cash flows.

Our businesses operate in changing market environments influenced by various state and federal legislative and regulatory initiatives regarding the restructuring of the energy industry, including competition in power generation and sale of electricity, natural gas, emissions and renewable energy certificates, and other commodities. Although we attempt to comply with changing legislative and regulatory requirements, there is a risk that we will fail to adapt to any such changes successfully or on a timely basis. Compliance with, or changes to, the requirements under these legal and regulatory regimes, including those proposed or implemented under the current presidential administration or during any future change of administration, or any repeal of existing beneficial laws or regulations, may adversely impact our businesses, results of operations, liquidity, financial condition, and cash flows.

Our businesses are subject to numerous state and federal laws (including, but not limited to, Texas Public Utility Regulatory Act, the Federal Power Act, the Natural Gas Policy Act, the Atomic Energy Act, the Public Utility Regulatory Policies Act of 1978, the Clean Air Act (CAA), the Clean Water Act (CWA), the Resource Conservation and Recovery Act (RCRA), the Energy Policy Act of 2005, the Dodd-Frank Wall Street Reform and the Consumer Protection Act and the Telephone Consumer Protection Act), changing governmental policy and regulatory actions (including those of the FERC, the NERC, the RCT, the MSHA, the EPA, the NRC, the DOJ, the FTC, the CFTC, state public utility commissions and state environmental regulatory agencies), and the rules, guidelines and protocols of ERCOT, CAISO, ISO-NE, MISO, NYISO and PJM with respect to various matters, including, but not limited to, market structure and design, operation of nuclear generation facilities, construction and operation of other generation facilities, development, operation and reclamation of lignite mines, recovery of costs and investments, decommissioning costs, market behavior rules, present or prospective wholesale and retail competition, administrative pricing mechanisms (and adjustments thereto), rates for wholesale sales of electricity, mandatory reliability standards and environmental matters. We, along with other market participants, are subject to electricity pricing constraints and market behavior and other competition-related rules and regulations. Additionally, Ambit's direct selling business (i) could be found by regulators not to be in compliance with applicable law or regulations, which may lead to our inability to obtain or maintain a license, permit, or similar certification and (ii) may be required to alter its compensation practices in order to comply with applicable federal or state law or regulations. Changes in, revisions to, or reinterpretations of, existing laws and regulations may have a material adverse effect on our businesses, results of operations, liquidity, financial condition and cash flows.

Extreme weather events have resulted, and in the future may result, in efforts by both federal and state government and regulatory agencies to investigate and determine the causes of such events. For example, as a result of Winter Storm Uri, we received a civil investigative demand from the Attorney General of Texas as well as a request for information from ERCOT, NERC, and other regulatory bodies related to this event. Winter Storm Elliott, in December 2022, also led to regulatory requests for information and notices of investigation by NERC, FERC, regional reliability entities, and independent market monitors for regions across the country. Such investigations have resulted, and in the future may result, in changes in laws or regulations that impact our industry and businesses including, but not limited to, additional requirements for winterization of various facets of the electricity supply chain including generation, transmission, and fuel supply; improvements in coordination among the various participants in the electricity supply chain during any future event; restrictions or limitations on the types of plans permitted to be offered to customers; potential revisions to the method of calculation of market compensation and incentives relating to the continued operation of assets that only run periodically, including during extreme weather events or other times of scarcity; and other potential legislative and regulatory corrective actions that may be taken. Previously announced or future legal proceedings, regulatory actions, or other administrative proceedings involving market participants may lead to adverse determinations or other findings of violations of laws, rules, or regulations, any of which may impact the ability of market participants to satisfy, in whole or in part, their respective obligations. For example, the Texas Legislature, the PUCT, ERCOT, FERC, and NERC have implemented new requirements and continue to consider future market design and other rule changes in response to Winter Storm Uri and other extreme weather events.

Finally, the regulatory environment has undergone significant changes in the last several years due to state and federal policies affecting wholesale and retail competition and the creation of incentives for the addition of large amounts of new renewable generation. For example, changes to, or development of, legislation that requires the use of clean renewable and alternate fuel sources or mandate the implementation of energy conservation programs that require the implementation of new technologies, could increase our capital expenditures and/or impact our financial condition. Changes enacted by the Texas Legislature through Senate Bill 2627, the Powering Texas Forward Act, to administer Texas Energy Fund (TEF) programs, which include grants and loans to finance the construction, maintenance, modernization, and operation of electric facilities in Texas, may negatively impact our financial condition if it materially changes market fundamentals. Additionally, in some retail energy markets, state legislators, government agencies and other interested parties have made proposals to change the use of market-based pricing, re-regulate areas of these markets that have previously been competitive, or permit electricity delivery companies to construct or acquire generation facilities. Other proposals to re-regulate the retail energy industry may be made, and legislative or other actions affecting electricity and natural gas deregulation or restructuring process may be delayed, discontinued or reversed in states in which we currently operate or may in the future operate. If such changes were to be enacted by a regulatory body, we may lose customers, incur higher costs and/or find it more difficult to acquire new customers. These changes are ongoing, and we cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on our business.

We are required to obtain, and to comply with, government permits and approvals.

We are required to obtain, and to comply with, numerous permits and licenses from federal, state and local governmental agencies. The process of obtaining and renewing necessary permits and licenses can be lengthy and complex and can sometimes result in the establishment of conditions that make the project or activity for which the permit or license was sought unprofitable or otherwise unattractive. In addition, such permits or licenses may be subject to denial, revocation or modification under various circumstances. Failure to obtain or comply with the conditions of permits or licenses, or failure to comply with applicable laws or regulations, may result in the delay or temporary suspension of our operations and electricity sales or the curtailment of our delivery of electricity to our customers and may subject us to penalties and other sanctions. Although various regulators routinely renew existing permits and licenses, renewal of our existing permits or licenses could be denied or jeopardized by various factors, including (a) failure to provide adequate financial assurance for closure, (b) failure to comply with environmental, health and safety laws and regulations or permit conditions, (c) local community, political or other opposition and (d) executive, legislative or regulatory action.

Our inability to procure and comply with the permits and licenses required for our operations, or the cost to us of such procurement or compliance, could have a material adverse effect on us. In addition, new environmental legislation or regulations, if enacted, or changed interpretations of existing laws, may cause activities at our facilities to need to be changed to avoid violating applicable laws and regulations or elicit claims that historical activities at our facilities violated applicable laws and regulations. In addition to the possible imposition of fines in the case of any such violations, we may be required to undertake significant capital investments and obtain additional operating permits or licenses, which could have a material adverse effect on us.

Our cost of compliance with existing and new environmental laws could have a material adverse effect on us.

We are subject to extensive environmental regulation by governmental authorities, including federal and state environmental agencies and/or attorneys general. We may incur significant additional costs beyond those currently contemplated to comply with these regulatory requirements. If we fail to comply with these regulatory requirements, we could be subject to administrative, civil or criminal liabilities and fines. Existing environmental regulations could be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur, including potential regulatory and enforcement developments related to air emissions and CCR, all of which could result in significant additional costs beyond those currently contemplated to comply with existing requirements. Any of the foregoing could have a material adverse effect on us.

The Biden Administration recently finalized or proposed several regulatory actions establishing new requirements for control of certain emissions from sources, including electricity generation facilities. In the future, the EPA may also propose and finalize additional regulatory actions that may adversely affect our existing generation facilities or our ability to cost-effectively develop new generation facilities. There is no assurance that the currently installed emissions control equipment at our lignite, coal and/or natural gas-fueled generation facilities will satisfy the requirements under any future EPA or state environmental regulations. Some of the recent regulatory actions, such as the EPA's Good Neighbor Plan for the 2015 Ozone NAAQS, the final rule to regulated GHG emissions that would replace the ACE rule, and actions under the Regional Haze program, could require us to install significant additional control equipment, resulting in potentially material costs of compliance for our generation units, including capital expenditures, higher operating and fuel costs and potential production curtailments or plant retirements. These costs or operation impacts could have a material adverse effect on us. In January 2025, President Trump issued a series of executive orders, including an order titled Unleashing American Energy (the "Order") that ordered that all federal agencies are to review all existing regulations, orders and other actions for consistency with the policy goals in that Order, and develop an action plan within 30 days to resolve any policy inconsistencies. In addition, the Order stated that the U.S. Attorney General may request stays of litigation involving any identified rules or actions from the review. We expect the Trump Administration to review the recent actions of the Biden Administration, but the outcome of those actions is uncertain.

We may not be able to obtain or maintain all required environmental regulatory approvals. If there is a delay in obtaining any required environmental regulatory approvals, if we fail to obtain, maintain or comply with any such approval or if an approval is retroactively disallowed or adversely modified, the operation of our generation facilities could be stopped, disrupted, curtailed or modified or become subject to additional costs. Any such stoppage, disruption, curtailment, modification or additional costs could have a material adverse effect on us.

In addition, we may be responsible for any on-site liabilities associated with the environmental condition of facilities that we have acquired, leased, developed or sold, regardless of when the liabilities arose and whether they are now known or unknown. In connection with certain acquisitions and sales of assets, we may obtain, or be required to provide, indemnification against certain environmental liabilities. Another party could, depending on the circumstances, assert an environmental claim against us or fail to meet its indemnification obligations to us, which could have a material adverse effect on us.

We could be materially and adversely affected if new federal or state legislation or regulations are adopted to address global climate change that could require efforts that exceed or are more expensive than our currently planned initiatives or if we are subject to lawsuits for alleged damage to persons or property resulting from greenhouse gas emissions.

There is continuing emphasis nationally and internationally on global climate change and how GHG emissions, such as CO_2, contribute to global climate change. Over the last several years, the U.S. Congress has considered and debated several proposals intended to address climate change using different approaches, including a cap on carbon emissions with emitters allowed to trade unused emission allowances (cap-and-trade), a tax on carbon or GHG emissions, incentives for the development of low-carbon technology and federal renewable portfolio standards. In July 2019, the EPA finalized the ACE rule that developed emissions guidelines that states must use when developing plans to regulate GHG emissions from existing coal-fueled electric generation units. In January 2021, the ACE rule was vacated by the D.C. Circuit Court and remanded to the EPA for further consideration in accordance with the court's ruling. The D.C. Circuit Court's decision was appealed to the U.S. Supreme Court. In June 2022, the U.S. Supreme Court issued its decision in *West Virginia v. EPA*, in which it held that the EPA does not have the authority to apply generation shifting in the regulation of GHG emissions. The judgment reversed the D.C. Circuit Court's decision and remanded the case for further proceedings consistent with the U.S. Supreme Court's opinion. In May 2024, the EPA issued a more stringent and more encompassing rule to replace the ACE rule. The GHG rule issued in May 2024 is currently being challenged in the D.C. Circuit after the U.S. Supreme Court declined to issue a stay of that rule. We expect the Trump Administration to review the May 2024 GHG rule. Additionally, pursuant to the Order, the Administrator of the EPA, in collaboration with the heads of any other relevant agencies, will submit joint recommendations to the Director of the Office of Management and Budget on the legality and continuing applicability of the December 2009 Endangerment Finding. In addition, a number of federal court cases have been filed in recent years asserting damage claims related to GHG emissions, and the results in those proceedings could establish adverse precedent that might apply to companies (including us) that produce GHG emissions. We could be materially and adversely affected if federal and/or state legislation or regulations that address global climate change require efforts that exceed or are more expensive than our currently planned initiatives or if we are subject to lawsuits for alleged damage to persons or property resulting from GHG emissions.

Additionally, in January 2021, President Biden issued written notification to the United Nations of the U.S.'s intention to rejoin the Paris Agreement, effective in February 2021. However, in January 2025, President Trump signed an Executive Order announcing the withdrawal from the Paris Agreement.

Luminant's mining operations are subject to RCT oversight.

We currently own and operate, or are in the process of reclaiming, various surface lignite coal mines in Texas to provide fuel for our electricity generation facilities. We also own or lease, and are in the process of reclaiming, multiple waste-to-energy surface facilities in Pennsylvania. The RCT, which exercises broad authority to regulate reclamation activity, reviews on an ongoing basis whether Luminant is compliant with RCT rules and regulations and whether it has met all the requirements of its mining permits in Texas. Any new rules and regulations adopted by the RCT or the Department of Interior Office of Surface Mining, which also regulates mining activity nationwide, or any changes in the interpretation of existing rules and regulations, could result in higher compliance costs or otherwise adversely affect our financial condition or cause a revocation of a mining permit. Any revocation of a mining permit would mean that Luminant would no longer be allowed to mine lignite at the applicable mine to serve its generation facilities.

Luminant's lignite mining reclamation activity will require significant resources as existing and retired mining operations are reclaimed over the next several years.

In conjunction with Luminant's announcements in 2017 to retire several power generation assets and related mining operations, along with the reclamation obligations at the closed Martin Lake mines and continuous reclamation activity at its continuing mining operations for its mines related to the Oak Grove generation asset, Luminant is expected to spend a significant amount of money, internal resources and time to complete the required reclamation activities. For the next five years, Vistra is projected to spend approximately $238 million (on a nominal basis) to achieve its mining reclamation objectives.

Litigation, legal proceedings, regulatory investigations or other administrative proceedings could expose us to significant liabilities and reputational damage that could have a material adverse effect on us.

We are involved in the ordinary course of business in a number of lawsuits involving, among other matters, employment, commercial, and environmental issues, and other claims for injuries and damages. We evaluate litigation claims and legal proceedings to assess the likelihood of unfavorable outcomes and to estimate, if possible, potential losses. Based on these evaluations and estimates, when required by applicable accounting rules, we establish reserves and disclose the relevant litigation claims or legal proceedings, as appropriate. These evaluations and estimates are based on the information available to management at the time and involve a significant amount of judgment. Actual outcomes or losses may differ materially from current evaluations and estimates. The settlement or resolution of such claims or proceedings may have a material adverse effect on us. We use appropriate means to contest litigation threatened or filed against us, but the litigation environment poses a significant business risk.

We are also involved in the ordinary course of business in regulatory investigations and other administrative proceedings, and we are exposed to the risk of additional regulatory investigations or administrative proceedings. As we adopt new technologies, like artificial intelligence (AI), there is a risk that the content, analyses, recommendations, or judgments that AI applications assist in producing are alleged to be deficient, inaccurate, biased, or infringe on other's rights or property interests. Any such regulatory investigation or administrative proceeding could result in us incurring penalties and other costs which may have a material adverse effect on us.

Our retail businesses, which each have REP certifications that are subject to review of the public utility commissions in the states in which we operate, are subject to changing state rules and regulations that could have a material impact on the profitability of our business.

The competitiveness of our U.S. retail businesses partially depends on state regulatory policies that establish the structure, rules, terms and conditions on which services are offered to retail customers. Specifically, the public utility commissions and/or the attorney generals of the various jurisdictions in which the Retail segment operates may at any time initiate an investigation into whether our retail operations comply with certain commission rules or state laws and whether we have met the requirements for REP certification, including financial requirements. These state policies and investigations, which can include controls on the retail rates our retail businesses can charge, the imposition of additional costs on sales, restrictions on our ability to obtain new customers through various marketing channels and disclosure requirements, investigations into whether our retail operations comply with certain commission rules or state laws and whether we have met the requirements for REP certification, including financial requirements, can affect the competitiveness of our retail businesses. Any removal or revocation of a REP certification would mean that we would no longer be allowed to provide electricity service to retail customers in the applicable jurisdiction, and such decertification could have a material adverse effect on us. Additionally, state or federal imposition of net metering or renewable portfolio standard programs can make it more or less expensive for retail customers to supplement or replace their reliance on grid power. Our retail businesses may have limited ability to influence development of these state rules, regulations and policies, and our business model may be more or less effective, depending on changes to the regulatory environment.

Operational Risks

Volatile power supply costs and demand for power have and could in the future adversely affect the financial performance of our retail businesses.

Although we are the primary provider of our retail businesses' wholesale electricity supply requirements, our retail businesses purchase a portion of their supply requirements from third parties. As a result, the financial performance of our retail business depends on their ability to obtain adequate supplies of electric generation from third parties at prices below the prices they charge their customers. Consequently, our earnings and cash flows could be adversely affected in any period in which the retail businesses' wholesale electricity supply costs rise at a greater rate than the rates they charge to customers. The price of wholesale electricity supply purchases associated with the retail businesses' energy commitments can be different than that reflected in the rates charged to customers due to, among other factors:

- varying supply procurement contracts used and the timing of entering into related contracts;
- subsequent changes in the overall price of natural gas;
- daily, monthly or seasonal fluctuations in the price of natural gas relative to the 12-month forward prices;
- transmission constraints and the Company's ability to move power to our customers;
- out-of-market payments, uplifts, or other non-pass through charges, and

- changes in Market Heat Rate.

The retail businesses' earnings and cash flows could also be adversely affected in any period in which their customers' actual usage of electricity significantly varies from the forecasted usage, which could occur due to, among other factors, transmission and distribution outages, demand-side management programs, competition and economic conditions, or extreme weather events, such as Winter Storm Uri in February 2021.

Our retail operations are subject to significant competition from other REPs, which could result in a loss of existing customers and the inability to attract new customers.

We operate in a very competitive retail market where our retail operation faces significant competition for customers. We believe our brands are viewed favorably in these markets, but despite our commitment to providing superior customer service and innovative products, customer sentiment toward our brands, including by comparison to our competitors' brands, depends on certain factors beyond our control. For example, competitor REPs may offer different products, lower electricity prices and other incentives, which, despite our long-standing relationship with many customers, may attract customers away from us. If we are unable to successfully compete with competitors in the retail market it is possible our retail customer counts could decline, which could have a material adverse effect on us.

As we try to grow our retail business and operate our business strategy, we compete with various other REPs that may have certain advantages over us. For example, in new markets, our principal competitor for new customers may be the incumbent REP, which has the advantage of long-standing relationships with its customers, including well-known brand recognition. In addition to competition from the incumbent REP, we may face competition from a number of other energy service providers, other energy industry participants, or nationally branded providers of consumer products and services who may develop businesses that will compete with us. Some of these competitors or potential competitors may be larger than we are or have greater resources or access to capital than we have. Competitors may also incorporate emerging technology like generative AI into their businesses, services, and products more quickly or more successfully than we do. In retail markets with substantial competition, high customer acquisition costs may outweigh the potential margin and it may not be profitable for us to compete in these markets.

Our retail operations rely on the infrastructure of local utilities or independent transmission system operators to provide electricity to, and to obtain information about, our customers. Any infrastructure failure could negatively impact customer satisfaction and could have a material adverse effect on us.

The substantial majority of our retail operations depend on transmission and distribution facilities owned and operated by unaffiliated utilities to deliver the electricity that we sell to our customers. If transmission capacity is inadequate, our ability to sell and deliver electricity may be hindered and we may have to forgo sales or buy more expensive wholesale electricity than is available in the capacity-constrained area or, with respect to capacity performance in PJM and performance incentives in ISO-NE, we may be subject to significant penalties. For example, during some periods, transmission access is constrained in some areas of the Dallas-Fort Worth metroplex, where we have a significant number of customers. The cost to provide service to these customers may exceed the cost to provide service to other customers, resulting in lower operating margins. In addition, any infrastructure failure that interrupts or impairs delivery of electricity to our customers could negatively impact customer satisfaction with our service. Any of the foregoing could have a material adverse effect on us.

Cybersecurity attacks or technology systems failures could disrupt business operations and expose us to significant liabilities, reputational damage, loss of customers, and regulatory action.

Our businesses depend on the secure and reliable storage, processing and communication of electronic data and sophisticated computer hardware and software systems. Our information technology systems and infrastructure, and those of our vendors and suppliers, face constant threats that have in the past and could in the future compromise data confidentiality, integrity, or availability. While we have controls in place designed to protect our information technology (IT) infrastructure, such breaches and threats are becoming increasingly sophisticated and complex, requiring the continuing evolution of our program. A breach or similar IT incident could interrupt normal business operations and affect our ability to use our generation assets, customer information, or communication systems, which could have a material adverse effect on us.

Potential disruptions from cyber/data and physical security breaches to "critical cyber assets" that interrupt the delivery of power to the Bulk Electric System could incur penalties of up to $1 million per violation for failure to comply with mandatory electric reliability standards by FERC under the Energy Policy Act of 2005.

Further, our retail business requires us to regularly access, collect, store, and transmit customer data, including sensitive customer data. New data privacy and data protection laws and regulations, increased enforcement, and other government actions could impact our businesses, increase compliance costs, and failure to comply with these laws and regulations could adversely affect our business and financial results. Our retail business may need to provide access to customer data, including sensitive customer data, to third parties and service providers to provide services, such as call center operations. In certain circumstances, Vistra could incur liability for a third-party or service provider's misuse or loss of the data.

Although we take precautions to protect our infrastructure, we have been, and will likely continue to be, subject to attempts at phishing and other cybersecurity intrusions. International conflict increases the risk of state-sponsored cyber threats and escalated use of cybercriminal and cyber-espionage activities. In particular, the current geopolitical climate has further escalated cybersecurity risk, with various government agencies, including the Federal Bureau of Investigation (FBI) and the U.S. Cybersecurity & Infrastructure Security Agency, issuing warnings of increased cyber threats, particularly for U.S. critical infrastructure. As of the date of this report, the Company has not identified a cyber/data event causing any material operational, reputational or financial impact. However, we recognize the growing threat within the general marketplace and our industry, especially as generative AI becomes more widely used by threat actors. There is no assurance that we will be able to prevent or mitigate any such impacts in the future. In the event of a material cyber breach, critical operational capabilities to support our generation, commercial, or retail operations could be disrupted or lost. Additionally, customer, confidential, or proprietary data could be compromised, misused, or inappropriately disclosed. If critical operational capabilities or data were impacted, it could adversely affect our reputation, diminish customer confidence, expose us to legal or regulatory claims, impair our business strategy, or impact our results of operation or financial condition, which could have a material adverse effect on us. Our efforts to deter, identify, and mitigate future breaches may require additional, significant capital and operating costs and may not be successful.

We may suffer material losses, costs and liabilities due to operation risks, regulatory risks, and the risk of nuclear accidents arising from the ownership and operation of the nuclear generation facilities.

We own and operate nuclear generation facilities in Texas, Ohio, and Pennsylvania. The ownership and operation of nuclear generation facilities involves certain risks. These risks include:

- unscheduled outages or unexpected costs due to equipment, mechanical, structural, cybersecurity, insider threat, third-party compromise or other problems;
- inadequacy or lapses in maintenance protocols;
- the impairment of reactor operation and safety systems due to human error or force majeure;
- the costs of, and liabilities relating to, storage, handling, treatment, transport, release, use and disposal of radioactive materials;
- the costs of procuring nuclear fuel, including impacts from trade restrictions such as tariffs, embargoes, and quotas (see Item 7. *Management's Discussion and Analysis of Financial Condition, and Results of Operations – Significant Activities and Events, and Items Influencing Future Performance – Macroeconomic Conditions*);
- the costs of storing and maintaining spent nuclear fuel at our on-site dry cask storage facility;
- terrorist or cybersecurity attacks by nation-states or other threat actors and the cost to protect and recover against any such attack;
- the impact of a natural disaster;
- financial risk associated with retrospective insurance premium that could become due under secondary coverage required by the Price Anderson Act;
- limitations on the amounts and types of insurance coverage commercially available; and
- uncertainties with respect to the technological and financial aspects of modifying or decommissioning nuclear facilities at the end of their useful lives.

Our financial performance could be materially and negatively affected by matters arising from our ownership and operation of nuclear facilities, including any prolonged unavailability of any of our nuclear generation facilities. The following are among the more significant related risks:

- *Operational Risk.* Operations at any generation facility could degrade to the point where the facility would have to be shut down. If such degradations were to occur at a nuclear generation facility, the process of identifying and correcting the causes of the operational downgrade to return the facility to operation could require significant time and expense, resulting in both lost revenue and increased fuel and purchased power expense to meet supply commitments. Furthermore, a shut-down or failure at any other nuclear generation facility could cause regulators to require a shut-down or reduced availability at our nuclear generation facilities.

- *Regulatory Risk.* The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under it or the terms of the licenses of nuclear generation facilities. Unless extended, as to which no assurance can be given, the NRC operating license for the unit at the Perry Facility will expire in 2026, and is pending a license renewal application subject to review by the NRC. Changes in regulations by the NRC could require a substantial increase in capital expenditures or result in increased operating or decommissioning costs.

- *Spent Nuclear Fuel Storage*. Our nuclear operations produce various types of nuclear waste materials, including spent nuclear fuel. The availability of a national repository for the storage of spent nuclear fuel and the timing of that facility opening will significantly affect the costs associated with storage of spent nuclear fuel and the ultimate amounts received from the DOE to reimburse us for these costs. Any regulatory action relating to the timing and availability of a repository for spent nuclear fuel could adversely affect our ability to decommission fully our nuclear units. We cannot predict whether a fee may be established or to what extent in the future for spent nuclear fuel disposal.

- *Decommissioning Obligation and Funding*. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility.

  Actual costs to decommission our nuclear facilities may substantially exceed our estimates as a result of changes in the approach and timing of decommissioning activities, changes in decommissioning costs, changes in federal or state regulatory requirements, other changes in our estimates or ability to effectively execute on our planned decommissioning activities.

  Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from current estimates. In addition, financial market performance directly affects the asset values in the NDT trust funds. If the investments held by our PJM NDT funds are not sufficient to fund the decommissioning of our nuclear units, we could be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met.

- *Nuclear Accident Risk.* Although the safety record of our nuclear generation facilities generally has been very good, accidents and other unforeseen problems have occurred at nuclear stations both in the U.S. and elsewhere. The consequences of an accident can be severe and include loss of life, injury, lasting negative health impacts and property damage. Any accident, or perceived accident, could result in significant liabilities that may exceed our resources, including insurance coverages, and could damage our reputation. Such liabilities to third parties are currently covered by a primary layer of financial protection required by the Price Anderson Act in the form of insurance carried by the owners of each nuclear facility and by a secondary layer of insurance coverage into which each nuclear licensee in the country is required to contribute in the event of an accident at any facility which exceeds the primary level of coverage for that facility. Our potential exposure for the secondary layer of coverage is currently capped at $165.9 million per reactor but is subject to adjustment for inflation, and the total retrospective premium per reactor per incident is capped at $24.7 million in any one year. Any such resulting liability from a nuclear accident could exceed our resources, including insurance coverage, and could ultimately result in the suspension or termination of power generation from the impacted facility. Such accidents could also result in property damage to our nuclear plant and equipment, which could exceed coverage available under insurance provided by Nuclear Electric Insurance Limited. If a serious nuclear incident were to occur, our business, reputation, financial condition and results of operations could be materially adversely affected.

The operation and maintenance of power generation facilities and related mining operations are capital intensive and involve significant risks that could adversely affect our results of operations, liquidity and financial condition.

The operation and maintenance of power generation facilities and related mining operations involve many risks, including, as applicable, start-up risks, breakdown or failure of facilities, equipment or processes, operator error, lack of sufficient capital to maintain the facilities, the dependence on a specific fuel source, the ability to timely obtain parts for equipment repairs, the inability to transport our product to our customers in an efficient manner due to the lack of transmission capacity or the impact of unusual or adverse weather conditions or other natural events, or terrorist attacks, as well as the risk of performance below expected levels of output, efficiency or reliability, the occurrence of any of which could result in substantial lost revenues and/or increased expenses. A significant number of our facilities were constructed many years ago. Older generation equipment, even if maintained or refurbished in accordance with good engineering practices, may require significant capital expenditures to operate at peak efficiency or reliability. The risk of increased maintenance and capital expenditures arises from (a) increased starting and stopping of generation equipment due to the volatility of the competitive generation market and the prospect of continuing low wholesale electricity prices that may not justify sustained or year-round operation of all our generation facilities, (b) any unexpected failure to generate power, including failure caused by equipment breakdown or unplanned outage (whether by order of applicable governmental regulatory authorities, the impact of weather events or natural disasters or otherwise), (c) damage to facilities due to storms, natural disasters, wars, terrorist or cybersecurity attacks, including nation-state attacks or organized cybercrime and other catastrophic events and (d) the passage of time and normal wear and tear. Further, our ability to successfully and timely complete routine maintenance or other capital projects at our existing facilities is contingent upon many variables and subject to substantial risks. Should any such efforts be unsuccessful, we could be subject to additional costs or losses and write downs of our investment in the project.

We cannot be certain of the level of capital expenditures that will be required due to changing environmental and safety laws and regulations (including changes in the interpretation or enforcement thereof), needed facility repairs. The unexpected requirement of large capital expenditures could have a material adverse effect on us. Moreover, if we significantly modify a unit, we may be required to install the best available control technology or to achieve the lowest achievable emission rates as such terms are defined under the new source review provisions of the CAA, which would likely result in substantial additional capital expenditures.

In addition, unplanned outages at any of our generation facilities, whether because of equipment breakdown or otherwise, typically increase our operation and maintenance expenses and may reduce our revenues as a result of selling fewer MWh or non-performance penalties or require us to incur significant costs as a result of running one of our higher cost units or to procure replacement power at spot market prices in order to fulfill contractual commitments. If we do not have adequate liquidity to meet margin and collateral requirements, we may be exposed to significant losses, may miss significant opportunities and may have increased exposure to the volatility of spot markets, which could have a material adverse effect on us. Further, our inability to operate our generation facilities efficiently, manage capital expenditures and costs, and generate earnings and cash flows from our asset-based businesses could have a material adverse effect on our results of operations, financial condition or cash flows. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance, warranties or performance guarantees may not be adequate to cover our lost revenues, increased expenses or liquidated damages payments should we experience equipment breakdown or non-performance by contractors or vendors.

Operation of power generation facilities involves significant risks and hazards customary to the power industry that could have a material adverse effect on our revenues and results of operations, and we may not have adequate insurance to cover these risks and hazards. Our employees, contractors, customers and the general public may be exposed to a risk of injury due to the nature of our operations.

Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of equipment and delivering electricity to transmission and distribution systems. In addition to natural risks such as extreme weather, earthquake, flood, lightning, hurricane and wind, other human-made hazards, such as nuclear accidents, dam failure, gas or other explosions, mine area collapses, fire, structural collapse, machinery failure, and other dangerous incidents are inherent risks in our operations. These and other hazards have and may in the future cause significant personal injury or loss of life, severe damage to and destruction of property, plant, and equipment, contamination of, or damage to, the environment and suspension of operations. Further, our employees and contractors work in, and customers and the general public may be exposed to, potentially dangerous environments at or near our operations. As a result, employees, contractors, customers, and the general public are at risk for serious injury, including loss of life.

The occurrence of any one of these events has in the past and may in the future result in us being named as a defendant in lawsuits asserting claims for substantial damages, including for environmental cleanup costs, personal injury and property damage and fines and/or penalties. We maintain an amount of insurance protection that we consider adequate, but we cannot provide any assurance that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject and, even if we do have insurance coverage for a particular circumstance, we may be subject to a large deductible and maximum cap. A successful claim for which we are not fully insured could hurt our financial results and materially harm our financial condition. Further, due to rising insurance costs and changes in the insurance markets, including increasing pressure on firms that provide insurance to companies that own and operate fossil fuel generation, we cannot provide any assurance that our insurance coverage will continue to be available at all or at rates or on terms similar to those presently available. Any losses not covered by insurance could have a material adverse effect on our financial condition, results of operations or cash flows.

We have been and may in the future be materially and adversely affected by obligations to comply with federal and state regulations, laws, and other legal requirements that govern the operations, assessments, storage, closure, corrective action, disposal and monitoring relating to CCR.

As a result of electricity produced for decades at coal-fueled power plants in Illinois, Texas and Ohio, we manage large amounts of CCR material in surface impoundments. In addition to the federal requirements under the CCR rule, CCR surface impoundments will continue to be regulated by existing state laws, regulations and permits, as well as additional legal requirements that may be imposed in the future. These federal and state laws, regulations and other legal requirements may require or result in additional expenditures, increased operating and maintenance costs and/or result in closure of certain power generation facilities, which could affect the results of operations, financial position and cash flows of the Company. We have recognized ARO liabilities related to these CCR-related requirements based on costs of closure methods that our operations and environmental services teams determined were appropriate based on the existing closure requirements at the time we recorded those ARO liabilities, and is reasonably possible for those to increase once the IEPA determines final closure requirements for our Illinois sites. As the closure and CCR management work progresses and final closure plans and corrective action measures are developed and approved at each site, the scope and complexity of work and the amount of CCR material could be greater than current estimates and could, therefore, materially impact earnings through increased compliance expenditures.

The EPA was directed by the Biden Administration to review a number of environmental rules adopted by the EPA during the first Trump Administration, including the CCR rule, the ELG rule, the ACE rule and the particulate matter (PM), and NAAQS rules. All of these rules may significantly and adversely impact our existing coal fleet and may lead to accelerated plant closure timeframes. In addition, the new GHG rule and the PM2.5 NAAQS rule finalized in 2024 along with other NAAQS that may be issued in the future have the potential to adversely impact our natural gas-fired units. In January 2025, President Trump issued an executive Order, which among other things, requires the EPA to review many of the rules issued by the Biden Administration and further instructed that the U.S. Attorney General may request a stay of the litigation while the EPA conducts its review.

The EPA is reviewing applications submitted by us to extend closure deadlines for many of our CCR impoundments. The scope and cost of that closure work could increase significantly based on new or potential requirements imposed by the EPA or state agencies, including the EPA's interpretations on requirements for closure of CCR units. There is no assurance that our current assumptions for closure activities will be accepted by the EPA or state agencies. If ponds must be closed sooner than anticipated, plant closures timeframes may be accelerated.

The availability and cost of emission allowances could adversely impact our costs of operations.

We are required to maintain, through either allocations or purchases, sufficient emission allowances for SO_2, CO_2, and NO_X to support our operations in the ordinary course of operating our power generation facilities. These allowances are used to meet the obligations imposed on us by various applicable environmental laws. If our operational needs require more than our allocated allowances, we may be forced to purchase such allowances on the open market, which could be costly. If we are unable to maintain sufficient emission allowances to match our operational needs, we may have to curtail our operations so as not to exceed our available emission allowances or install costly new emission controls. As we use the emission allowances that we have purchased on the open market, costs associated with such purchases will be recognized as operating expense. If such allowances are available for purchase, but only at significantly higher prices, the purchase of such allowances could materially increase our costs of operations in the affected markets.

We have been and may in the future be materially and adversely affected by the effects of extreme weather conditions and seasonality.

We have been and may in the future be materially affected by weather conditions and our businesses may fluctuate substantially on a seasonal basis as the weather changes. In addition, we are subject to the effects of extreme weather conditions, including sustained or extreme cold or hot temperatures, hurricanes, floods, droughts, storms, fires, earthquakes or other natural disasters, which could stress our generation facilities and grid reliability, limit our ability to procure adequate fuel supply, or result in outages, damage or destroy our assets and result in casualty losses that are not ultimately offset by insurance proceeds, and could require increased capital expenditures or maintenance costs, including supply chain costs.

Moreover, an extreme weather event could cause disruption in service to customers due to downed wires and poles or damage to other operating equipment, which could result in us foregoing sales of electricity and lost revenue. Similarly, certain extreme weather events have previously affected, and may in the future, affect, the availability of generation and transmission capacity, limiting our ability to source or deliver power where it is needed or limit our ability to source fuel for our plants, including due to damage to rail or natural gas pipeline infrastructure. Additionally, extreme weather has resulted, and may in the future result, in (i) unexpected increases in customer load, requiring our retail operation to procure additional electricity supplies at wholesale prices in excess of customer sales prices for electricity, (ii) the failure of equipment at our generation facilities, (iii) a decrease in the availability of, or increases in the cost of, fuel sources, including natural gas, diesel and coal, or (iv) unpredictable curtailment of customer load by the applicable ISO/RTO in order to maintain grid reliability, resulting in the realization of lower wholesale prices or retail customer sales. For example, Winter Storm Uri in February 2021 had a material impact on our results of operations.

Additionally, climate change may produce changes in weather or other environmental conditions, including temperature or precipitation levels, and thus may impact consumer demand for electricity. In addition, the potential physical effects of climate change, such as increased frequency and severity of storms, floods, and other climatic events, could disrupt our operations and cause us to incur significant costs to prepare for or respond to these effects.

Weather conditions, which cannot be reliably predicted, could have adverse consequences by requiring us to seek additional sources of electricity when wholesale market prices are high or to sell excess electricity when market prices are low, as well as significantly limiting the supply of, or increasing the cost of our fuel supply, each of which could have a material adverse effect on our business, results of operations, financial condition and liquidity.

Events outside of our control, including an epidemic or outbreak of an infectious disease may materially adversely affect our business.

We face risks related to epidemics, outbreaks or other public health events that are outside of our control, and could significantly disrupt our operations and adversely affect our financial condition. The global or national outbreak of an illness or other communicable disease, or any other public health crisis may cause disruptions to our business and operational plans, as a result of a number of factors, including (a) a protracted slowdown of broad sectors of the economy, (b) changes in demand or supply for commodities, (c) significant changes in legislation or regulatory policy to address the pandemic (including prohibitions on certain marketing channels, moratoriums or conditions on disconnections or limits or restrictions on late fees), (d) reduced demand for electricity (particularly from commercial and industrial customers), (e) increased late or uncollectible customer payments, (f) negative impacts on the health of our workforce, (g) a deterioration of our ability to ensure business continuity (including increased vulnerability to cyber and other information technology risks), and (h) the inability of the Company's contractors, suppliers, and other business partners to fulfill their contractual obligations.

Changes in technology, increased electricity conservation efforts, or energy sustainability efforts may reduce the value of our business, introduce new or emerging risks, and may otherwise have a material adverse effect on us.

If we cannot adopt technological developments on a timely basis, demand for our services may decline, or we may face challenges in implementing or evolving our business strategy. Significant technological changes continue to impact our industry. To grow and remain competitive, we will need to adapt to changes in available technology like generative AI, continually invest in our assets, increase generation capacity, increase our use of low-carbon technologies, enhance our existing offerings, and introduce new offerings to meet our current and potential customers' changing service demands. Competitors may incorporate new technologies into their businesses, services, and products more quickly or more successfully than we do. Adopting new and sophisticated technologies may result in implementation issues, such as scheduling and supplier delays, unexpected or increased costs, technological constraints, regulatory issues, customer dissatisfaction, and other issues that could cause delays in launching new technological capabilities. This, in turn could result in significant costs or reduce the anticipated benefits of the technology change. As we adopt new technologies, like AI, there is a risk that the content, analyses, recommendations, or judgments that AI applications assist in producing are alleged to be deficient, inaccurate, biased, or infringe on other's rights or property interests. Our new services could fail to retain or gain acceptance in the marketplace, or costs associated with these services could be higher than anticipated. As such, our adoption of technology or failure to adopt technology could have a material adverse effect on our business, brand, financial condition, business strategy, and operating results.

Technological advances have improved, and are likely to continue to improve, for existing and alternative methods to produce and store power, including natural gas turbines, wind turbines, fuel cells, hydrogen, micro turbines, photovoltaic (solar) cells, batteries, concentrated solar thermal devices, novel nuclear technologies (including small modular reactors), geothermal energy (including enhanced geothermal systems and advanced geothermal systems), and long duration energy storage, along with improvements in traditional technologies. Such technological advances may be superior to, or may not be compatible with, some of our existing technologies, investments and infrastructure, and may require us to make significant expenditures to remain competitive, and have resulted, and are expected to continue to reduce the costs of power production or storage, which may result in the obsolescence of certain of our operating assets. Consequently, the value of our more traditional generation assets could be significantly reduced as a result of these competitive advances, which could have a material adverse effect on us and our future success will depend, in part, on our ability to anticipate and successfully adapt to technological changes, to offer services and products that meet customer demands and evolving industry standards. In addition, changes in technology have altered, and are expected to continue to alter, the channels through which retail customers buy electricity (*i.e.*, self-generation or distributed-generation facilities). To the extent self-generation or distributed generation facilities become a more cost-effective option for customers, our financial condition, operating cash flows and results of operations could be materially and adversely affected.

Technological advances in demand-side management, large-scale residential or commercial virtual power plants, and increased conservation efforts could result in a decrease in electricity demand. A significant decrease in electricity demand as a result of such efforts would significantly reduce the value of our generation assets. Certain regulatory and legislative bodies have introduced or are considering requirements and/or incentives to reduce power consumption. Effective power conservation by our customers could result in reduced electricity demand or significantly slow the growth in such demand. Any such reduction in demand could have a material adverse effect on us. Furthermore, we may incur increased capital expenditures if we are required to increase investment in conservation measures. Additionally, increased governmental and consumer focus on energy sustainability efforts, including desire for, or incentives related to, the development, implementation and usage of low-carbon technology, may result in decreased demand for the traditional generation technologies that we currently own and operate.

We may potentially be affected by emerging technologies that may over time affect change in capacity markets and the energy industry overall including distributed generation and clean technology.

Some of these emerging technologies are distributed renewable energy technologies, energy efficiency, broad consumer adoption of electric vehicles, distributed generation, energy storage devices, fuel cells, nuclear small modular reactors, and linear generators. Additionally, large-scale cryptocurrency mining, AI data centers, and increased industrial electrification are becoming increasingly prevalent in certain markets, including ERCOT, and many of these facilities are "behind-the-meter." Such emerging technologies could affect the price of energy, levels of customer-owned generation, customer expectations and current business models and make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. These emerging technologies may also affect the financial viability of utility counterparties and could have significant impacts on wholesale market prices, which could ultimately have a material adverse effect on our financial condition, results of operations and cash flows could be materially adversely affected.

The loss of the services of our "key" management and personnel could adversely affect our ability to successfully operate our businesses.

Our future success will depend on our ability to continue to attract and retain highly qualified personnel. We compete for such personnel with many other companies, in and outside of our industry, government entities and other organizations. Potential difficulties in attracting and retaining highly qualified, skilled employees could restrict our ability to adequately support our business needs and/or result in increased personnel costs. In addition, effective succession planning is important to our long-term success. Failure to timely and effectively ensure transfer of knowledge and smooth transitions involving senior management and other key personnel could hinder our strategic planning and execution.

We could be materially and adversely impacted by strikes or work stoppages by our unionized employees.

As of December 31, 2024, we had approximately 1,940 employees covered by collective bargaining agreements. The terms of all current collective bargaining agreements covering represented personnel engaged in lignite mining operations, lignite-, coal-, natural gas- and nuclear-fueled generation operation, as well as some battery operations, expire on various dates between February 2025 and March 2028, but remain effective thereafter unless and until terminated by either party. In the event that our union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strife or disruption, we would be responsible for procuring replacement labor or we could experience reduced power generation or outages. We have in place strike contingency plans that address the procurement of replacement labor. Strikes, work stoppages or the inability to negotiate current or future collective bargaining agreements on favorable terms or at all could have a material adverse effect on us.

Risks Related to Our Structure and Ownership of our Common Stock

Vistra is a holding company and its ability to obtain funds from its subsidiaries is structurally subordinated to existing and future liabilities of its subsidiaries.

Vistra is a holding company that does not conduct any business operations of its own. As a result, Vistra's cash flows and ability to meet its obligations are largely dependent upon the operating cash flows of Vistra's subsidiaries and the payment of such operating cash flows to Vistra in the form of dividends, distributions, loans or otherwise. These subsidiaries are separate and distinct legal entities from Vistra and have no obligation (other than any existing contractual obligations) to provide Vistra with funds to satisfy its obligations. Any decision by a subsidiary to provide Vistra with funds to satisfy its obligations, whether by dividends, distributions, loans or otherwise, will depend on, among other things, such subsidiary's results of operations, financial condition, cash flows, cash requirements, contractual prohibitions and other restrictions, applicable law and other factors. The deterioration of income from, or other available assets of, any such subsidiary for any reason could limit or impair its ability to pay dividends or make other distributions to Vistra.

Evolving expectations from stakeholders, including investors, on ESG issues, including climate change and sustainability matters, and erosion of stakeholder trust or confidence could influence actions or decisions about our company and our industry and could adversely affect our business, operations, financial results or stock price.

Companies across all industries are facing evolving expectations or increasing scrutiny from stakeholders related to their approach to ESG matters. For Vistra, reliability, affordability, safety, climate change, and stakeholder relations remain primary focus areas, and changing expectations of our practices and performance across these and other ESG areas may impose additional costs or create exposure to new or additional risks. Our operations, projects and growth opportunities require us to have strong relationships with key stakeholders, including local communities and other groups directly impacted by our activities, as well as governments and government agencies, investor advocacy groups, certain institutional investors, investment funds and others which are increasingly focused on sustainability practices. Certain financial institutions have announced policies to presently or in the future cease investing or to divest investments in companies that derive any or a specified portion of their income from, or have any or a specified portion of their operations in, coal and/or other fossil fuels.

We are strategically focused on meeting growing demand for electricity as we ensure reliability and affordability while being mindful of growing stakeholder interest in our plans to transition to low-to-no carbon power generation sources. As we work through this transition, our prioritization of reliability and affordability may prevent us from achieving our targets as expected, which could impact stakeholder trust and confidence. Any such erosion of stakeholder trust and confidence, evolving expectations from stakeholders on such ESG issues, and such parties' resulting actions or decisions about our company and our industry could have negative impacts on our business, operations, financial results, and stock price, including:

- negative stakeholder sentiment toward us and our industry, including concerns over environmental or sustainability matters and potential changes in federal and state regulatory actions related thereto;
- loss of business or loss of market share, including to competitors who do not have any, or comparable amounts, of operations involving fossil fuels;
- loss of ability to hire and retain top talent;
- loss of ability to secure growth opportunities;
- the inability to, or increased difficulties and costs of, obtaining services, materials, or insurance from third parties;
- reductions in our credit ratings or increased costs of, or limited access to, capital;
- delays in project execution;
- legal action;
- increased regulatory oversight;
- impediments on our ability to acquire or renew rights-of-way or land rights on a timely basis and on acceptable terms;
- changing investor sentiment regarding investment in the power and utilities industry or our company; and
- restricted access to and cost of capital.

We may not pay any dividends on our common stock in the future, and we may not realize the anticipated benefits of our share repurchase program.

The Board has adopted a dividend program which we initiated in the first quarter of 2019. Each dividend under the program will be subject to declaration by the Board and, thus, may be subject to numerous factors in existence at the time of any such declaration including, but not limited to, prevailing market conditions, our results of operations, financial condition and liquidity, contractual prohibitions and other restrictions with respect to the payment of dividends. There is no assurance that the Board will declare, or that we will pay, any dividends on our common stock in the future.

The Board has approved a share repurchase program in an aggregate authorized amount of $6.75 billion. Under this share repurchase program or any other future share repurchase programs, we may make share repurchases through a variety of methods, including open share market purchases or privately negotiated transactions. The timing and amount of repurchases, if any, will depend on factors such as the stock price, economic and market conditions, and corporate and regulatory requirements. Any failure to repurchase shares after we have announced our intention to do so may negatively impact our reputation, investor confidence and the price of our common stock.

Holders of our preferred stock may have interests and rights that are different from our common stockholders.

We are permitted under our certificate of incorporation to issue up to 100,000,000 shares of preferred stock. We can issue shares of our preferred stock in one or more series and can set the terms of the preferred stock without seeking any further approval from our common stockholders. Any preferred stock that we issue may rank ahead of our common stock in terms of dividend priority or liquidation premiums and may have greater voting rights than our common stock, which could dilute the value of our common stock to current stockholders and could adversely affect the market price of our common stock. As of December 31, 2024, 1,000,000 shares of Series A Preferred Stock, 1,000,000 shares of Series B Preferred Stock, and 476,081 shares of Series C Preferred Stock were issued and outstanding. The Preferred Stock represents a perpetual equity interest in the Company and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date; *provided*, the Company may redeem the Preferred Stock at the specified times (or upon certain specified events) at the applicable redemption price set forth in the certificate of designation of each of the Series A Preferred Stock, Series B Preferred Stock, and Series C Preferred Stock, respectively (Certificates of Designation). The Preferred Stock is not convertible into or exchangeable for any other securities of the Company. Upon the liquidation, dissolution or winding up of the Company, whether voluntary or involuntary, after payment or provision for payment of the debts and other liabilities of the Company, the holders of Preferred Stock will be entitled to receive, pro rata and in preference to the holders of any other capital stock, an amount per share equal to $1,000 plus accrued and unpaid dividends thereon, if any.

Unless we have received the affirmative vote or consent of the holders of at least two-thirds of the outstanding Series A Preferred Stock, the holders of at least two-thirds of the outstanding Series B Preferred Stock and the holders of at least two-thirds of the outstanding Series C Preferred Stock, each voting as a separate class, we may not adopt any amendment to our certificate of incorporation (including the applicable Certificates of Designation) that would have a material adverse effect on the powers, preferences, duties, or special rights of such series of Preferred Stock, subject to certain exceptions. In addition, unless we have received the affirmative vote or consent of the holders of at least two-thirds of the outstanding Series A Preferred Stock, the holders of at least two-thirds of the outstanding Series B Preferred Stock and the holders of at least two-thirds of the outstanding Series C Preferred Stock, voting as a class together with the holders of any parity securities upon which like voting rights have been conferred and are exercisable, we may not: (i) create or issue any senior securities, (ii) create or issue any parity securities (including any additional Preferred Stock) if the cumulative dividends payable on the outstanding Preferred Stock (or parity securities, if applicable) are in arrears; (iii) create or issue any additional Preferred Stock or any parity securities with an aggregate liquidation preference, together with the issued and outstanding Preferred Stock and any parity securities that are then outstanding, of greater than $2.5 billion, and (iv) engage in any Transaction that results in a Covered Disposition (as such terms are defined in the Certificates of Designation).

In addition, holders of the Preferred Stock are entitled to receive, when, as, and if declared by our Board, semi-annual cash dividends on the Preferred Stock, which are cumulative from the applicable initial issuance date of the Preferred Stock and payable in arrears, and unless full cumulative dividends have been or contemporaneously are being paid or declared on the Preferred Stock, we may not (i) declare or pay any dividends on any junior securities, including our common stock, or (ii) redeem or repurchase any parity securities or junior securities, subject to limited exceptions set forth in the Certificates of Designation. There is no assurance that the Board will declare, or that we will pay, any dividends on our Preferred Stock in the future. The holders of Preferred Stock (along with any parity securities then outstanding with similar rights) are entitled to elect two additional directors in the event any dividends on Preferred Stock are in arrears for three or more semi-annual dividend periods (whether or not consecutive), and such directors may have competing and different interests to those elected by our common stockholders. The dividend rate for the Series A Preferred Stock from and including the initial issuance date of October 15, 2021 until the first reset date of October 15, 2026 will be 8.0% per annum of the $1,000 liquidation preference per share of Series A Preferred Stock. The dividend rate for the Series B Preferred Stock from and including the initial issuance date of December 10, 2021 until the first reset date of December 15, 2026 will be 7.0% per annum of the $1,000 liquidation preference per share of Series B Preferred Stock. The dividend rate for the Series C Preferred Stock from and including the initial issuance date of December 29, 2023 until the first reset date of January 15, 2029 will be 8.875% per annum of the $1,000 liquidation preference per share of Series C Preferred Stock. On and after the first reset date of the Series A Preferred Stock, the dividend rate on the Series A Preferred Stock for each subsequent five-year period (each, a Reset Period) will be adjusted based upon the applicable Treasury rate, plus a spread of 6.93% per annum; provided that the applicable Treasury rate for each Reset Period will not be lower than 1.07%. On and after the first reset date of the Series B Preferred Stock, the dividend rate on the Series B Preferred Stock for each Reset Period will be adjusted based upon the applicable Treasury rate, plus a spread of 5.74% per annum; provided that the applicable Treasury rate for each Reset Period will not be lower than 1.26%. On and after the first reset date of the Series C Preferred Stock, the dividend rate on the Series C Preferred Stock for each Reset Period will be adjusted based upon the applicable Treasury rate, plus a spread of 5.045% per annum; provided that the applicable Treasury rate for each Reset Period will not be lower than 3.830%. In the event that the Company does not exercise its option to redeem all the shares of Preferred Stock within 120 days after the first date on which a Change of Control Trigger Event (as defined in the Certificate of Designation) occurs, the then-applicable dividend rate for the Preferred Stock will be increased by 5.00%.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 1C. CYBERSECURITY

The Company has a cybersecurity and incident response program designed to assess, identify, and manage material risks from cybersecurity threats, including matters related to the cybersecurity of the Company's critical infrastructure, data, or information technology systems and the Company's actions to prepare for, identify, assess, respond, mitigate and remediate material cyber, information security, or technology risks (collectively referred to as Information Security). This program includes:

- operating a Cyber Security Operations Center;
- raising employee awareness through annual general and job-specific cybersecurity trainings and employee phishing simulations;
- maintaining defined cyber incident response plans;
- enhancing security measures to protect our systems and data;
- evolving monitoring capabilities to improve early detection and rapid response to potential cyber threats; and
- adapting to new work environments that include off-site work through mitigation of remote network risk to our internal systems, assets, or data.

Cybersecurity represents an important component of the Company's overall approach to enterprise risk management and is integrated into the risk management process and ongoing assessment. In addition to an internal security program, we strive to stay ahead of the threat landscape by actively monitoring and conducting due diligence on key third-party vendors' Information Security programs and risks. This includes qualitative assessments to gain a deeper understanding of their security posture and potential vulnerabilities. We make strategic investments in our perimeter and internal defenses, cyber security operations center, and regulatory compliance activities with the advice of consultants and third parties. Moreover, to minimize risk, we maintain an insurance policy that provides coverage for matters relating to Information Security.

Vistra's Chief Information Officer (CIO) ensures Information Security is built into the Company's larger technology strategy and oversees our Chief Information Security Officer (CISO). Our CISO and his Information Security team are responsible for leading the enterprise-wide information security strategy, policy, standards, architecture, and processes. Additionally, our Cyber Incident Response Teams under the CISO are responsible for monitoring and analyzing the Company's cybersecurity posture in partnership with Risk and Legal.

The CIO and CISO collaborate with our internal audit department and external consultants to review information technology-related risks (based upon the National Institute of Standards and Technology (NIST) Cybersecurity Framework) as part of the overall Vistra cyber risk management process. Through these processes, the CIO and CISO are informed about and monitor the prevention, detection, mitigation, and remediation of cybersecurity threats.

We also participate in industry groups and with regulators to gain additional knowledge, including, but not limited to, the Federal Bureau of Investigation, U.S. Cybersecurity and Infrastructure Security Agency, U.S. Department of Homeland Security, Electricity Information Sharing and Analysis Center, U.S. Cyber Emergency Response Team, the NRC and NERC. We apply the knowledge gained through industry partnerships, government organizations, external cyber risk platforms, and program maturity assessments to improve our processes to detect and mitigate cyber threats.

As of the date of this report, we have not identified any impacts from cybersecurity threats, including those from any previous cybersecurity incidents, that have materially affected our results of operation or financial condition. However, despite our efforts, we cannot eliminate all risks from cybersecurity threats, or provide assurances that we have not experienced undetected cybersecurity incidents. For additional information on risks from cybersecurity threats, see Item 1A. *Risk Factors*.

The Sustainability and Risk Committee of the Board has been delegated oversight responsibility of Vistra's Information Security. Vistra periodically engages third-party advisors to provide cybersecurity oversight and tabletop training to the full Board to further our commitment to responsible oversight of cybersecurity risk management. At least quarterly, our CIO reports to the Board on our Information Security program, including cybersecurity risks and threats (including the emerging threat landscape), an assessment of our Information Security program, and the status of projects to strengthen our Information Security program. In furtherance of our commitment to responsible oversight of cybersecurity risk management, in 2023, the Board appointed a director who brings extensive cybersecurity expertise to the Board.

Our CIO serves as head of Vistra's Technology Services and is responsible for ensuring the reliability, security, and continued development of the Company's technology platforms and delivering new solutions to support the business. The CIO has served in various senior information technology roles in public companies for over 30 years, including Keurig Dr. Pepper Inc., General Motors, Pfizer, and Electronic Data Systems.

Our CISO has over 23 years of information technology experience. He has held technology positions across various areas — including infrastructure management, application management, architecture, operations, and cybersecurity — and brings expertise from Farmers Insurance and Zurich Insurance.

Item 2. PROPERTIES

The following table presents our asset fleet as of December 31, 2024 by segment. All of our facilities are 100% (fee simple) owned.

Facility	Location	ISO/RTO	Technology	Primary Fuel	Net Capacity (MW) (a)
Texas Segment					
Ennis	Ennis, TX	ERCOT	CCGT	Natural Gas	366
Forney	Forney, TX	ERCOT	CCGT	Natural Gas	1,912
Hays	San Marcos, TX	ERCOT	CCGT	Natural Gas	1,047
Lamar	Paris, TX	ERCOT	CCGT	Natural Gas	1,180
Midlothian	Midlothian, TX	ERCOT	CCGT	Natural Gas	1,596
Odessa	Odessa, TX	ERCOT	CCGT	Natural Gas	1,180
Wise	Poolville, TX	ERCOT	CCGT	Natural Gas	787
DeCordova	Granbury, TX	ERCOT	CT	Natural Gas	260
Morgan Creek	Colorado City, TX	ERCOT	CT	Natural Gas	390
Permian Basin	Monahans, TX	ERCOT	CT	Natural Gas	325
Graham	Graham, TX	ERCOT	ST	Natural Gas	630
Lake Hubbard	Dallas, TX	ERCOT	ST	Natural Gas	921
Stryker Creek	Rusk, TX	ERCOT	ST	Natural Gas	685
Trinidad	Trinidad, TX	ERCOT	ST	Natural Gas	244
Coleto Creek	Goliad, TX	ERCOT	ST	Coal	650
Martin Lake	Tatum, TX	ERCOT	ST	Coal	2,250
Oak Grove	Franklin, TX	ERCOT	ST	Coal	1,600
Comanche Peak (b)	Glen Rose, TX	ERCOT	Nuclear	Uranium	2,400
Brightside	Live Oak County, TX	ERCOT	Solar	Renewable	50
Emerald Grove	Crane County, TX	ERCOT	Solar	Renewable	108
Upton 2	Upton County, TX	ERCOT	Solar/Battery	Renewable	190
DeCordova	Granbury, TX	ERCOT	Battery	Renewable	260
Total Texas Segment					**19,031**

Facility	Location	ISO/RTO	Technology	Primary Fuel	Net Capacity (MW) (a)
East Segment					
Independence	Oswego, NY	NYISO	CCGT	Natural Gas	1,212
Bellingham	Bellingham, MA	ISO-NE	CCGT	Natural Gas	566
Blackstone	Blackstone, MA	ISO-NE	CCGT	Natural Gas	544
Casco Bay	Veazie, ME	ISO-NE	CCGT	Natural Gas	543
Lake Road	Dayville, CT	ISO-NE	CCGT	Natural Gas	827
Masspower	Indian Orchard, MA	ISO-NE	CCGT	Natural Gas	281
Milford	Milford, CT	ISO-NE	CCGT	Natural Gas	600
Baldwin	Baldwin, IL	MISO	Solar/Battery	Renewable	70
Coffeen	Coffeen, IL	MISO	Solar/Battery	Renewable	46
Baldwin	Baldwin, IL	MISO	ST	Coal	1,185
Newton	Newton, IL	MISO	ST	Coal	615
Kincaid	Kincaid, IL	PJM	ST	Coal	1,108
Miami Fort 7 & 8	North Bend, OH	PJM	ST	Coal	1,020
Fayette	Masontown, PA	PJM	CCGT	Natural Gas	726
Hanging Rock	Ironton, OH	PJM	CCGT	Natural Gas	1,430
Hopewell	Hopewell, VA	PJM	CCGT	Natural Gas	370
Kendall	Minooka, IL	PJM	CCGT	Natural Gas	1,288
Liberty	Eddystone, PA	PJM	CCGT	Natural Gas	607
Ontelaunee	Reading, PA	PJM	CCGT	Natural Gas	600
Sayreville	Sayreville, NJ	PJM	CCGT	Natural Gas	349
Washington	Beverly, OH	PJM	CCGT	Natural Gas	711
Calumet	Chicago, IL	PJM	CT	Natural Gas	380
Dicks Creek	Monroe, OH	PJM	CT	Natural Gas	155
Pleasants	Saint Marys, WV	PJM	CT	Natural Gas	388
Miami Fort (CT)	North Bend, OH	PJM	CT	Fuel Oil	77
Beaver Valley 1 & 2	Shippingport, PA	PJM	Nuclear	Uranium	1,872
Perry	Perry, OH	PJM	Nuclear	Uranium	1,268
Davis-Besse	Oak Harbor, OH	PJM	Nuclear	Uranium	908
Total East Segment					**19,746**
West Segment					
Moss Landing 1 & 2	Moss Landing, CA	CAISO	CCGT	Natural Gas	1,020
Moss Landing	Moss Landing, CA	CAISO	Battery	Renewable	750
Oakland	Oakland, CA	CAISO	CT	Fuel Oil	110
Total West Segment					**1,880**
Total capacity					**40,657**

(a) Approximate net generation capacity. Actual net generation capacity may vary based on a number of factors, including ambient temperature. We have not included units that have been retired or are out of operation. See Note 6 to the Financial Statements for additional information.

Our wholesale commodity risk management group also procures renewable energy credits from renewable generation in ERCOT and PJM to support our electricity sales to wholesale and retail customers to satisfy the increasing demand for renewable resources from such customers. As of December 31, 2024, Vistra had long-term agreements to procure renewable energy credits from approximately 950 MW of renewable generation. These renewable generation sources deliver electricity when conditions make them available, and, when on-line, they generally compete with baseload units. Because they cannot be relied upon to meet demand continuously due to their dependence on weather and time of day, these generation sources are categorized as non-dispatchable and create the need for intermediate/load-following resources to respond to changes in their output.

Item 3. LEGAL PROCEEDINGS

See Note 15 to the Financial Statements for additional information.

Item 4. MINE SAFETY DISCLOSURES

Vistra currently owns and operates, or is in the process of reclaiming, 12 surface lignite coal mines in Texas to provide fuel for its electricity generation facilities. Vistra also owns or leases, and is in the process of reclaiming, two waste-to-energy surface facilities in Pennsylvania. These mining operations are regulated by the MSHA under the Federal Mine Safety and Health Act of 1977, as amended (the Mine Act), along with other federal and state regulatory agencies such as the RCT and Office of Surface Mining. The MSHA inspects U.S. mines, including Vistra's mines, on a regular basis, and if it believes a violation of the Mine Act or any health or safety standard or other regulation has occurred, it may issue a citation or order, generally accompanied by a proposed fine or assessment. Such citations and orders can be contested and appealed, which often results in a reduction of the severity and amount of fines and assessments and sometimes results in dismissal. Disclosure of MSHA citations, orders, and proposed assessments are provided in Exhibit 95.1 to this annual report on Form 10-K.

PART II

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

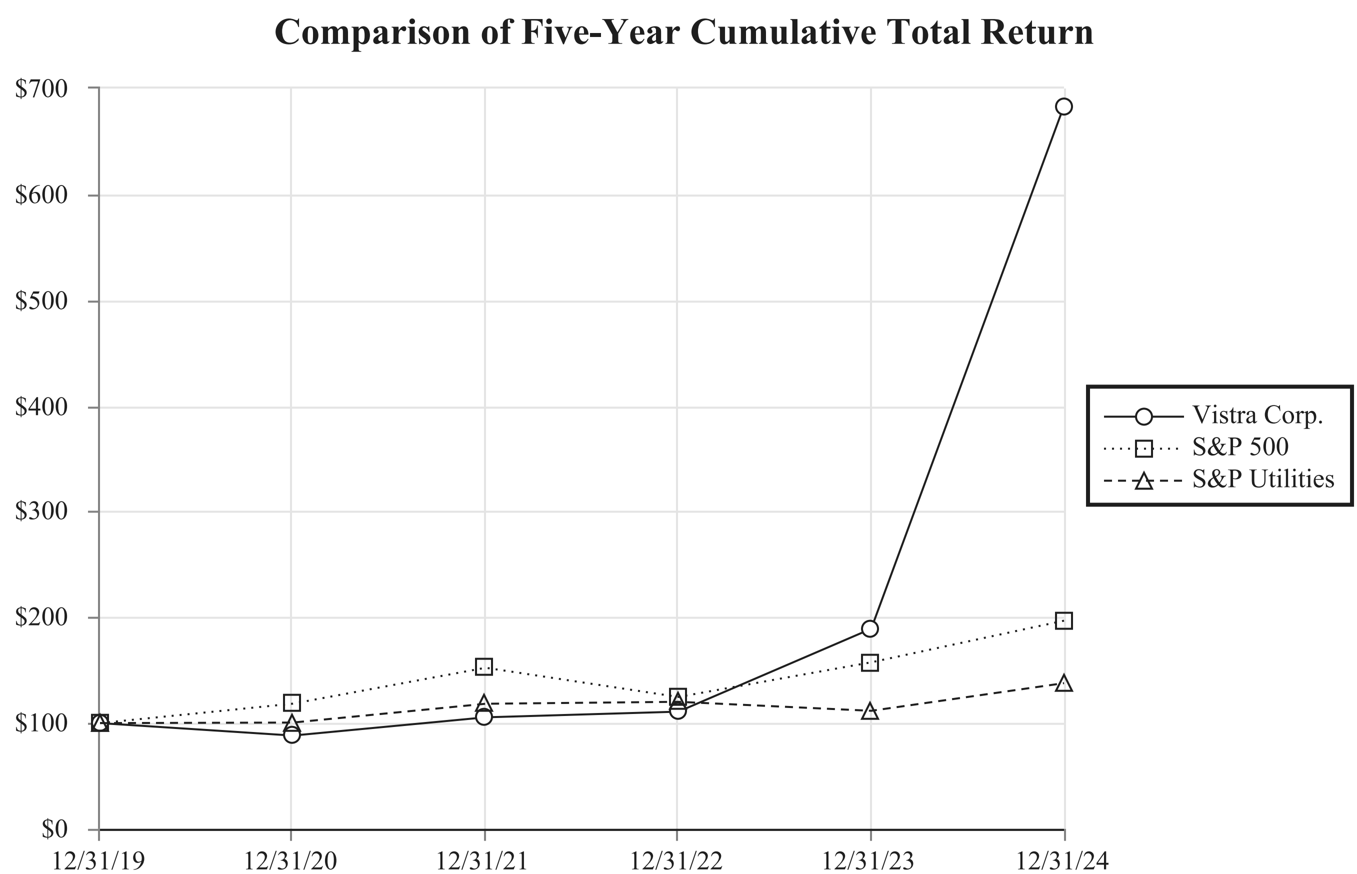
Vistra's common stock is listed and traded on the NYSE under the symbol "VST". Vistra's authorized capital stock consists of 1,800,000,000 shares of common stock with a par value of $0.01 per share.

As of February 24, 2025, there were 403 stockholders of record.

The Board has authority to declare dividends to the holders of our common stock. The Board intends to continue the payment of dividends to the holders of the Company's common stock in the future. The declaration and payment of future dividends, however, will be at the discretion of the Board and will depend on numerous factors in existence at the time of any such declaration including, but not limited to, prevailing market conditions, Vistra's results of operations, financial condition and liquidity, Delaware law and contractual limitations.

Stock Performance Graph

The performance graph below compares Vistra's cumulative total return on common stock during the five-year period from December 31, 2019 through December 31, 2024 with the cumulative total returns of the S&P 500 Stock Index (S&P 500) and the S&P Utility Index (S&P Utilities). The graph below compares the return in each period assuming that $100 was invested at December 31, 2019 in Vistra's common stock, the S&P 500 and the S&P Utilities, and that all dividends were reinvested.



	December 31,					
	2019	2020	2021	2022	2023	2024
Vistra Corp.	$ 100.00	$ 88.22	$ 105.47	$ 110.83	$ 189.20	$ 683.61
S&P 500	$ 100.00	$ 118.39	$ 152.34	$ 124.73	$ 157.48	$ 196.85
S&P Utilities	$ 100.00	$ 100.52	$ 118.29	$ 120.14	$ 111.63	$ 137.79

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

Purchases of Equity Securities by the Issuer

The following table provides information about our repurchase of common stock, during the three months ended December 31, 2024.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of a Publicly Announced Program	Maximum Dollar Amount of Shares that may yet be Purchased under the Program (in millions)
October 1 - October 31, 2024	464,487	$ 126.99	464,487	$ 2,177
November 1 - November 30, 2024	425,674	$ 144.66	425,674	$ 2,115
December 1 - December 31, 2024	735,536	$ 144.52	735,536	$ 2,009
For the quarter ended December 31, 2024	1,625,697	$ 139.55	1,625,697	$ 2,009

In October 2021, the Board authorized a share repurchase program (Share Repurchase Program). Under this program, shares of the Company's common stock may be repurchased in open market transactions, privately negotiated transactions, or other means in accordance with federal securities laws. The timing, number, and value of shares repurchased will be determined at our discretion, considering factors such as capital allocation priorities, stock market price, general market and economic conditions, legal requirements, and compliance with debt agreements and preferred stock certificates of designation. We expect to complete repurchases under the Share Repurchase Program by the end of 2026.

	Amount Authorized for Share Repurchases
	(in billions)
Board Authorization Dates:	
October 2021	$ 2.00
August 2022	1.25
March 2023	1.00
February 2024	1.50
October 2024	1.00
Cumulative authorization at December 31, 2024	$ 6.75

See Note 16 to the Financial Statements for additional information.

Item 6. [RESERVED]

Not applicable.

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

The following discussion and analysis of our financial condition and results of operations should be read together with the consolidated financial statements and related notes included in Item 8. *Financial Statements and Supplementary Data*. See Item 7. *Management's Discussion and Analysis of Financial Condition, and Results of Operations* in our 2023 Form 10-K for a discussion of our financial condition and results of operations for the year ended December 31, 2022 and for the year ended December 31, 2023 compared to the year ended December 31, 2022, which is incorporated here by reference. The Sunset segment was eliminated in the fourth quarter of 2024, resulting in the recast of results for four coal facilities to the East segment and one coal facility to the Texas segment (see Note 19 to the Financial Statements). The recast is reflected in the results of operations for the years ended December 31, 2024 and 2023. The re-segmentation did not result in a material change in the reported results for the East and Texas segments for the year ended December 31, 2023 compared to the year ended December 31, 2022.

Significant Activities and Events, and Items Influencing Future Performance

Merger with Energy Harbor

On March 1, 2024 (Merger Date), pursuant to a transaction agreement dated March 6, 2023 (Transaction Agreement), (i) Vistra Operations transferred certain of its subsidiary entities into Vistra Vision, (ii) Black Pen Inc., a wholly owned subsidiary of Vistra, merged with and into Energy Harbor, (iii) Energy Harbor became a wholly-owned subsidiary of Vistra Vision, and (iv) affiliates of Nuveen Asset Management, LLC (Nuveen) and Avenue Capital Management II, L.P. (Avenue) exchanged a portion of the Energy Harbor shares held by Nuveen and Avenue for a 15% equity interest of Vistra Vision (collectively, Energy Harbor Merger). The Energy Harbor Merger combined Energy Harbor's and Vistra's nuclear and retail businesses and certain Vistra Zero renewables and energy storage facilities to provide diversification and scale across multiple carbon-free technologies (dispatchable and renewables/storage) and the retail business. The cash consideration for Energy Harbor Merger was funded by Vistra Operations using a combination of cash on hand and borrowings under the Commodity-Linked Facility, the Receivables Facility and the Repurchase Facility. See Note 2 to the Financial Statements.

Acquisition of Noncontrolling Interest

On September 18, 2024 (the UPA Transaction Date), Vistra Operations and Vistra Vision Holdings I LLC, an indirect subsidiary of Vistra Operations (Vistra Vision Holdings), entered into separate Unit Purchase Agreements (as amended, the UPAs) with each of Nuveen and Avenue, pursuant to which Vistra Vision Holdings agreed to purchase each of Nuveen's and Avenue's combined 15% noncontrolling interest in Vistra Vision for approximately $3.2 billion in cash (collectively, the Transaction). The Transaction closed on December 31, 2024 (the Closing Date) and Vistra Vision Holdings now owns 100% of the equity interests in Vistra Vision. See Note 9 to the Financial Statements.

Nuclear Plant License Renewals

In July 2024, our application for license renewal at our two-unit Comanche Peak Nuclear Plant was approved by the NRC. The licenses for Units 1 and 2 now extend into 2050 and 2053, respectively, an additional 20 years beyond our original licenses.

In 2023, the Perry Nuclear Plant filed a license extension application to operate through 2046, an additional 20 years beyond the existing license. A decision from the NRC is expected in late 2025.

Planned Gas-Fueled Dispatchable Power in ERCOT

In May 2024, we announced our intention to add up to 2,000 MW of dispatchable, natural gas-fueled electricity capacity in west, central, and north Texas consisting of the following projects:

- Building up to 860 MW of advanced simple-cycle peaking plants to be located in west Texas to support the increasing power needs of the region, including the state's oil and gas industry.
- Repowering the coal-fueled Coleto Creek Power Plant near Goliad, Texas, set to retire in 2027 to comply with EPA rules, as a natural-gas fueled plant with up to 600 MW of capacity.
- Completing upgrades at existing natural gas-fueled plants that will add more than 500 MW of summer capacity and 100 MW of winter capacity.

Our announced plan is based on market reforms that policymakers passed in the 2023 Texas legislative session, which ERCOT and the PUCT are currently implementing. These market reforms are focused on grid reliability and proper market signals. If successfully implemented, they could offer the regulatory framework necessary for Vistra to confidently make the long-term investments in these capacity projects. In addition, in July 2024, we filed applications with the PUCT under the Texas Energy Fund loan program seeking financing for the 860 MW of new advanced simple-cycle peaking plants referenced above. In August 2024, the PUCT notified Vistra that an application for one of its west Texas advanced simple-cycle peaking plants was selected for due diligence as part of the Texas Energy Fund loan program, which is ongoing. Vistra's other application for a second west Texas gas plant remains active. An invitation to due diligence does not mean an applicant is awarded a loan. Vistra's decision to move forward with the new west Texas gas plant project is contingent upon supportive market reforms, approval of our Texas Energy Fund loan application, and other factors, including state and federal environmental regulations and long-term wholesale trends that continue to support gas generation.

Moss Landing 300 Battery and Martin Lake Unit 1 Updates

In January 2025, a fire occurred at our Moss Landing 300 MW battery energy storage facility in CAISO. We are still investigating the cause and impacts, but expect to write off approximately $400 million of plant value to depreciation expense in the first quarter of 2025, representing the facility's remaining net book value. Moss Landing 300 is part of the Moss Landing complex, which includes two other battery facilities and a gas plant, with an aggregate book value of approximately $1 billion including Moss Landing 300. While the gas plant is operational, the other two battery facilities remain offline as we investigate the fire. Additional costs incurred from the events include loss of revenue from the facilities being offline, and may include litigation costs and penalties under contracts. We will continue to assess if a triggering event has occurred to evaluate impairment for the other complex assets.

On November 27, 2024, we experienced a fire at Unit 1 of our Martin Lake facility in ERCOT, an 815 MW unit. The depreciation expense associated with the damaged property was less than $1 million. We currently expect the unit to return to service in June 2025.

We expect to recover a significant portion of the direct losses incurred from each event through property damage insurance and business interruption insurance. However, given uncertainty in timing of recoveries and potential indirect impacts to other facilities, we cannot predict the net impact these events will have on our results of operations for 2025.

***Inflation Reduction Act of 2022* (IRA)**

In August 2022, the U.S. enacted the IRA, which, among other things, implements substantial new and modified energy tax credits, including recognizing the value of existing carbon-free nuclear power by providing for a nuclear PTC, a solar PTC, and a first-time stand-alone battery storage investment tax credit. The IRA also implements a 15% corporate alternative minimum tax (CAMT) on book income of certain large corporations, and a 1% excise tax on net stock repurchases. The section 45U nuclear PTC is available to existing nuclear facilities from 2024 through 2032 and provides a federal tax credit of up to $15 per MWh, subject to phase out as power prices increase above $25 per MWh (each subject to annual inflation adjustments). The Company accounts for transferable ITCs and PTCs we expect to receive by analogy to the grant model within International Accounting Standards 20, *Accounting for Government Grants and Disclosures of Government Assistance*. As discussed in Note 4, we recognized transferable nuclear PTC revenues of $545 million in the year ended December 31, 2024. Treasury regulations are expected to further define the scope of the legislation in many important respects, including critical guidance interpreting the nuclear PTC. This guidance could have a material impact on our estimate and would be reflected as a change in estimate in the period in which the guidance is received. We do not expect Vistra to be subject to the CAMT in the 2024 tax year as it applies only to corporations with a three-year average annual adjusted financial statement income in excess of $1 billion. We have taken the CAMT and relevant extensions or expansions of existing tax credits applicable to projects in our immediate development pipeline into account when forecasting cash taxes.

Financial and Operating Performance

The following are financial and operating highlights we achieved in the execution of our four strategic priorities:

Long-term, attractive earnings profile through the integrated business model.

- We continued to execute our integrated business model through exceptional operational performance by capitalizing on market opportunities that drove strong earnings for the year ended December 31, 2024. This highlights our competitive advantage of coupling retail with our reliable and efficient generation fleet and wholesale commodity risk management capabilities, which reduces the effects of commodity price movements and contributes to the stability and predictability of our cash flows.
- Our commercial team focused on effectively and efficiently managing risk by opportunistically hedging and optimizing our assets and business positions, which led to strong plant operating performance and energy margins.
- Our retail brands served the retail electricity and natural gas needs of end-use residential, small business, and commercial and industrial electricity customers through multiple sales and marketing channels with products and solutions that differentiates Vistra from our competitors.

Disciplined capital allocation.

- During the year ended December 31, 2024, we paid dividends to common stockholders totaling $305 million.

- In February 2024 and October 2024, the Board authorized incremental amounts of $1.5 billion and $1.0 billion, respectively, under our stock repurchase program established in October 2021. During the year ended December 31, 2024, we repurchased 16.6 million shares for $1.2 billion under the program. Through February 24, 2025, total shares repurchased under the program totaled 160 million shares for $4.9 billion, and we have $1.9 billion available for additional repurchases under the program (see Note 16 to the Financial Statements).

Maintaining a resilient balance sheet.

- We further diversified our sources of liquidity and improved associated borrowing costs and credit terms through a number of enhancements and amendments to our facilities throughout the year, including (i) the expansion and extension of both our Revolving Credit Facility (expanded by $265 million and extended to 2029) and our Commodity-Linked Facility (expanded facility limit by $175 million and extended to October 2025), (ii) amending both the Vistra Operations Term Loan B-3 Facility and the Vistra Zero Term Loan B Facility to reduce the fixed spread interest by 25 and 75 basis points, respectively, (iii) establishing a $500 million alternative letter of credit facility, and (iv) expanding and extending the Receivables Facility (expanded the purchase limit by $250 million and extended to July 2025).
- In April 2024, we issued $500 million of 6.000% senior secured notes due 2034 and $1.0 billion of 6.875% senior unsecured notes due 2032. The net proceeds from these issuances were used to refinance senior secured debt maturities in May 2024 and July 2024 and for general corporate purposes.
- In December 2024, we issued $500 million of 5.050% senior secured notes due 2026 and $750 million of 5.700% senior secured notes due 2034. The net proceeds from these issuances were or will be used for general corporate purposes, including to refinance senior secured debt maturities in May 2025 and payments associated with the Transaction for the purchase of the remaining interest in Vistra Vision.
- In December 2024, we entered into the BCOP Credit Agreement to fund the development of solar generation and battery ESS facilities in Illinois and Texas.

Strategic energy transition focused on the reliability, affordability, and sustainability of electric grid.

- In March 2024, we completed the acquisition of Energy Harbor, adding an additional 4,048 MW of nuclear generation to our fleet.
- We reached commercial operations for two solar facilities totaling 112 MW of capacity at retired plant sites in Illinois and continued development and construction activities on additional facilities in Texas and at retired or to-be-retired plant sites in Illinois.
- We announced plans to repower the Coleto Creek coal generation facility as a natural gas-fueled facility upon its retirement no later than 2027.

During the year ended December 31, 2024, our operating segments delivered strong operating performance with a disciplined focus on cost management, while generating and selling essential electricity in a safe and reliable manner. Our performance reflected strong plant operating performance, growth of our retail business and the effectiveness of our comprehensive hedging strategy.

Macroeconomic Conditions

Historically, the base case assumption for U.S. electricity demand was for modest growth driven by the interplay of growth in population, industrial activity (such as an on-shore manufacturing) and new demand sources (such as electric vehicles), partially offset by continued advancements in energy efficiency. Multiple demand drivers such as emergence of large load data centers and electrification of oil field operations (specifically in the Permian Basin of west Texas), are expected to continue to accelerate load growth in the geographic regions we serve. We are in various discussions with interested counterparties for the potential sale of power from our nuclear and gas facilities pursuant to long-term agreements to supply large load facilities. Such potential transactions are subject to certain risks and uncertainties, including potential regulatory review and/or approval and adverse legislative action, which could impact the timing of, and our ability to consummate, any potential transaction.

The industry continues to experience supply chain constraints and labor shortages that have reduced the availability of certain equipment and supply relevant to construction of new generation facilities, and increased (i) the lead time to procure certain materials necessary to maintain, and (ii) the labor costs associated with maintenance activity on our natural gas, nuclear and coal fleet. We are proactively managing the increased costs of materials and supply chain disruptions and continuing to prudently re-evaluate the business cases and timing of our planned development projects, which has resulted in a deferral of some of our planned capital spend for our renewables projects and could impact the feasibility of additional projects. In addition, we have proactively engaged our suppliers to secure key materials needed to maintain our existing generation facilities prior to future planned outages, and our Vistra Zero operational and development projects are anticipated to benefit from the impact of the IRA. The inflationary environment continues to drive elevated interest rates, resulting in increased refinancing or borrowing costs, including future non-recourse financing for our development projects and future refinancing expected in connection with future debt maturities.

We continue to closely monitor developments in the Russia and Ukraine conflict, specifically with regards to, (i) sanctions (or potential sanctions) against Russian energy exports and Russian nuclear fuel supply and enrichment activities, and (ii) actions by Russia to limit energy deliveries, which may further impact commodity prices in Europe and globally. The Prohibiting Russian Uranium Imports Act (PRUI Act) was approved by Congress, signed into law by President Biden, and took effect on August 11, 2024. The PRUI Act prohibits importation of Russian uranium; however, the Department of Energy can issue waivers (subject to decreasing annual caps) until December 31, 2027 if there is no alternate source of low-enriched uranium available to keep U.S. nuclear reactors operating or is in the national interest. Additionally, passage of the PRUI Act enabled the allocation of $2.72 billion in federal funding to ramp up production of domestic uranium fuel. On November 15, 2024, the Russian Federation temporarily suspended shipments of uranium to the U.S., stating that they would grant future export licenses on a case-by-case basis. Our 2024 and 2025 refueling plans have not been affected by the Russia and Ukraine conflict, nor have we seen any disruption to the delivery of nuclear fuel impacting our refueling schedules. We work with a diverse set of global nuclear fuel cycle suppliers to procure our nuclear fuel years in advance. We have nuclear fuel contracted to support all our refueling needs through 2029. We continue to take affirmative action by building strategic inventory and deploying mitigating strategies in our procurement portfolio to ensure we can secure the nuclear fuel needed to continue to operate our nuclear facilities through potential Russian supply disruption.

Capacity Markets

PJM, NYISO, ISO-NE, MISO and CAISO ensure long-term grid reliability through monthly, semiannual, annual, and multi-year capacity auctions or bilateral transactions where power suppliers commit to making the generation resources available to the ISO as needed for a specific time period. We participate in these capacity market auctions and also enter into bilateral capacity sales, and a portion of our East, and West segment revenues are impacted by the capacity auction results or bilateral contracts. The following information summarizes the auction pricing for zones in which we operate as well as our capacity auction and bilateral capacity sales by planning period. Performance incentive rules increase capacity payments for those resources that are providing excess energy or reserves during a shortage event, while penalizing those that produce less than the required level.

PJM

Reliability Pricing Model (RPM) auction results, for the zones in which our assets are located, are as follows for each planning year:

	2024-2025	2025-2026
	(average price per MW-day)	
RTO zone	$ 28.92	$ 269.92
ComEd zone	28.92	269.92
MAAC zone	49.49	269.92
EMAAC zone	53.60	269.92
ATSI zone	28.92	269.92
DEOK zone	96.24	269.92
DOM zone	28.92	444.26

Our capacity sales in PJM, net of purchases, aggregated by planning year and capacity type through planning year 2025-2026, are as follows:

	East Segment	
	2024-2025	2025-2026
CP auction capacity sold, net (MW)	9,935	10,255
Bilateral capacity sold, net (MW)	2,127	330
Total segment capacity sold, net (MW)	12,062	10,585
Average price per MW-day	$ 41.38	$ 267.12

NYISO

The most recent seasonal auction results for NYISO's Rest-of-State zones, in which the capacity for our Independence plant clears, are as follows for each planning period:

	Winter 2024 - 2025
Price per kW-month	$ 2.00

Due to the short-term, seasonal nature of the NYISO capacity auctions, we monetize the majority of our capacity through bilateral trades. Our capacity sales, aggregated by season through winter 2026-2027, are as follows:

	East Segment				
	Winter 2024 - 2025	Summer 2025	Winter 2025 - 2026	Summer 2026	Winter 2026 - 2027
Auction capacity sold (MW)	77	—	—	—	—
Bilateral capacity sold (MW)	943	550	268	—	—
Total capacity sold (MW)	1,020	550	268	—	—
Average price per kW-month	$ 3.09	$ 4.51	$ 4.10	$ —	$ —

ISO-NE

The most recent Forward Capacity Auction results for ISO-NE Rest-of-Pool, in which most of our assets are located, are as follows for each planning year:

	2024-2025	2025-2026	2026-2027	2027-2028
Price per kW-month	$ 2.61	$ 2.59	$ 2.59	$ 3.58

We continue to market and pursue longer term multi-year capacity transactions that extend through planning year 2027-2028.

	East Segment			
	2024-2025	2025-2026	2026-2027	2027-2028
Auction capacity sold (MW)	3,221	3,032	2,960	3,261
Bilateral capacity sold (MW)	78	78	58	8
Total capacity sold (MW)	3,299	3,110	3,018	3,269
Average price per kW-month	$ 3.10	$ 2.72	$ 2.60	$ 3.58

MISO

The capacity auction results for MISO Local Resource Zone 4, in which our assets are located, are as follows for each planning year:

	2024-2025
Price per MW-day	$ 20.08

MISO capacity sales through planning year 2027-2028 are as follows:

	East Segment			
	2024-2025	2025-2026	2026-2027	2027-2028
Auction capacity sold (MW)	1,095	—	—	—
Bilateral capacity sold (MW)	682	891	515	24
Total MISO segment capacity sold (MW)	1,777	891	515	24
Average price per kW-month	$ 3.02	$ 4.52	$ 4.44	$ 4.96

CAISO

Our capacity sales as part of the California Public Utilities Commission Resource Adequacy (RA) Program in California, aggregated by calendar year for 2025 through 2028 for Moss Landing, are as follows:

	West Segment			
	2025	2026	2027	2028
Bilateral capacity sold (Avg MW)	1,816	1,575	1,275	750

Electricity Prices

The price of electricity has a significant impact on our operating revenues and purchased power costs. Electricity prices are typically set by the cost to fuel a generation facility and the amount of fuel needed to generate one unit of electricity (Heat Rate) from the generation facility. Market Heat Rate is the implied relationship between wholesale electricity prices and the commodity price of the marginal supplier (generally natural gas plants).

Wholesale electricity prices generally track to increases or decreases in the price of natural gas, with exceptions such as when ERCOT power prices rise significantly during weather events as a result of the scarcity of available generation resources relative to power demand. The price of natural gas is volatile; therefore, the costs to operate a natural gas-fueled generation facility can be volatile as well. In contrast to our natural gas-fueled generation facilities, changes in natural gas prices have no significant effect on the cost of generating power at our nuclear-, lignite- and coal-fueled facilities; however, all other factors being equal, changes in natural gas prices affect our operating margins on these facilities as electricity prices generally track to natural gas prices. Other variables that could impact electricity prices include, but are not limited to, the price of other fuels, generation resources in the region, weather, on-going competition, emerging technologies, and macroeconomic and regulatory factors.

The wholesale market price of electricity divided by the market price of natural gas represents the Market Heat Rate. Market Heat Rate can be affected by a number of factors, including generation availability, mix of assets and the efficiency of the marginal supplier (generally natural gas-fueled generation facilities) in generating electricity. Our Market Heat Rate exposure is impacted by changes in the availability of generation resources, such as additions and retirements of generation facilities, and mix of generation assets. For example, increasing renewable (wind and solar) generation capacity generally depresses Market Heat Rates, particularly during periods when total demand is relatively low. However, increasing penetration of renewable generation capacity may also contribute to greater volatility of wholesale market prices independent of changes in the price of natural gas, given their intermittent nature.

As a result of our exposure to the variability of natural gas prices and Market Heat Rates, retail sales and hedging activities are critical to our operating results and maintaining consistent cash flow levels. Our integrated power generation and retail electricity business provides us opportunities to hedge our generation position utilizing retail electricity markets as a sales channel. Our approach to managing electricity price risk focuses on the following:

- employing disciplined, liquidity-efficient hedging and risk management strategies through physical and financial energy-related contracts intended to partially hedge gross margins;
- continuing focus on cost management to better withstand gross margin volatility;
- following a retail pricing strategy that appropriately reflects the value of our product offering to customers, the magnitude and costs of commodity price, liquidity risk and retail demand variability; and
- improving retail customer service to attract and retain high-value customers.

Critical Accounting Estimates

See Note 1 of the consolidated financial statements for a description of our accounting policies. The following is a discussion of our most critical accounting estimates, judgments and uncertainties that are inherent in our application of GAAP.

Business Combinations

Determining fair values of assets acquired and liabilities assumed in the Energy Harbor Merger requires significant estimates and judgments. We determined fair value based on the estimated price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. See Note 2 to the Financial Statements. The determination of the fair value of property, plant, and equipment contributed and acquired, as well as nuclear decommissioning asset retirement obligations required the most significant level of estimation uncertainty.

The fair value of each power plant acquired in the Energy Harbor Merger and the fair value of the contributed nuclear business was estimated using a combination of the income approach and the market approach. The income approach was based on the discounted cash flow method, incorporating (i) our estimates of forecasted future growth and long-term prices of electricity, capacity, and nuclear fuel, and (ii) financial performance including revenues, gross margins, operating expenses, taxes, working capital, and capital asset requirements. Projected cash flows were then discounted to a present value employing a discount rate that accounts for the estimated market weighted-average cost of capital, along with any risks unique to the subject cash flows. These estimates are subjective in nature and require judgment to interpret market data. The market valuation method utilized prices paid for reasonably similar assets by other purchasers in the relevant market, with adjustments relating to physical differences in the asset as well as their locations.

See *Asset Retirement Obligations (ARO)* critical accounting estimate for methodology and assumptions used to estimate the nuclear decommissioning ARO acquired in the Energy Harbor Merger.

Derivative Instruments and Mark-to-Market Accounting

We enter into contracts for the purchase and sale of energy-related commodities, as well as other derivative instruments such as options, swaps, futures, and forwards, primarily to manage commodity price and interest rate risks. Under accounting standards related to derivative instruments and hedging activities, these instruments are subject to mark-to-market accounting, and the determination of market values for these instruments is based on numerous assumptions and estimation techniques.

Mark-to-market accounting recognizes changes in the fair value of derivative instruments in the financial statements as market prices change. Such changes in fair value are accounted for as unrealized mark-to-market gains and losses in net income with an offset to derivative assets and liabilities. The availability of quoted market prices in energy markets is dependent on the type of commodity (e.g., natural gas, electricity, etc.), time period specified and delivery point. Where quoted market prices are not available, the fair value is based on unobservable inputs, which require significant judgment. Derivative instruments valued based on unobservable inputs primarily include (i) forward sales and purchases of electricity (including certain retail contracts), natural gas and coal, (ii) electricity, natural gas and coal options, and (iii) financial transmission rights. In computing fair value for derivatives, each forward pricing curve is separated into liquid and illiquid periods. The liquid period varies by delivery point and commodity. Generally, the liquid period is supported by exchange markets, broker quotes and frequent trading activity. For illiquid periods, fair value is estimated based on forward price curves developed using proprietary modeling techniques that take into account available market information and other inputs that might not be readily observable in the market. Any significant changes to these inputs could result in a material change to the value of the assets or liabilities recorded in the consolidated balance sheets and could result in a material change to the unrealized gains or losses recorded in the consolidated statements of operations.

Accounting standards related to derivative instruments and hedging activities allow for normal purchase or sale elections, which generally eliminate the requirement for mark-to-market recognition in net income. Normal purchases and sales (NPNS) are contracts that provide for physical delivery of quantities expected to be used or sold over a reasonable period in the normal course of business and are accounted for on an accrual basis. Determining whether a contract qualifies for the normal purchase or sale election requires judgment as to whether or not the contract will physically deliver and requires that management ensure compliance with all associated qualification and documentation requirements. If it is determined that a transaction designated as a normal purchase or sale no longer meets the scope exception, the related contract would be recorded on the balance sheet at fair value with immediate recognition through earnings.

See Notes 11 and 12 to the Financial Statements for additional information.

Accounting for Income Taxes

Our income tax expense and related consolidated balance sheet amounts involve significant management estimates and judgments. Amounts of deferred income tax assets and liabilities, as well as current and noncurrent accruals, involve estimates and judgments of the timing and probability of recognition of income and deductions by taxing authorities. Further, we assess the likelihood that we will be able to realize or utilize our deferred tax assets. If realization is not more likely than not, we would record a valuation allowance against such deferred tax assets for the amount we would not expect to utilize, which would reduce the carrying value of the deferred tax amounts. When evaluating the need for a valuation allowance, we consider all available positive and negative evidence, including the following:

- the creation and timing of future income associated with the reversal of deferred tax liabilities in excess of deferred tax assets;
- the existence, or lack thereof, of statutory limitations on the period that net operating losses may be carried forward; and
- the amounts and history of income or losses, adjusted for certain non-recurring items.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, our forecasted financial condition and results of operations in future periods, as well as final review of filed tax returns by taxing authorities.

Income tax returns are regularly subject to examination by applicable tax authorities. In management's opinion, the liability recorded pursuant to income tax accounting guidance related to uncertain tax positions reflects future taxes that may be owed as a result of any examination.

See Notes 1 and 5 to the Financial Statements for additional information.

Asset Retirement Obligations (ARO)

An ARO liability is initially recorded at fair value when it is initially incurred and the amount of the liability can be reasonably estimated. In estimating the ARO liability, we are required to make significant estimates and assumptions. Our ARO liabilities primarily relate to nuclear generation plant decommissioning, land reclamation related to lignite mining, and remediation or closure of coal ash basins. On the Merger Date, we recognized ARO liabilities for the Beaver Valley, Perry and Davis-Besse nuclear plants acquired from Energy Harbor.

For the estimates and assumptions of the nuclear generation plant decommissioning, we use unit-by-unit decommissioning cost studies to provide a marketplace assessment of the expected costs and estimates of the timing of decommissioning activities, which are validated by comparison to current decommissioning projects within the industry and other estimates. We consider the following decommissioning scenarios: (i) DECON, which assumes major decommissioning activities begin shortly after the facility ceases operations, and (ii) SAFSTOR, which assumes the nuclear facility is placed and maintained in a condition during decommissioning that allows the nuclear facility to be safely stored until subsequently decontaminated within 60 years after the facility ceases operations. Decommissioning cost studies are updated for each of our nuclear units at least every five years unless circumstances warrant a more frequent update. In estimating the liability assumed in the Energy Harbor Merger, we have included an assumption that Vistra receives a license extension of 20 years from the NRC to continue to operate the Perry Nuclear Plant through 2046.

The estimates and assumptions required for the lignite mining land reclamation include, estimates such as costs to fill in mining pits and interpretation of the mining permit closure requirements. We estimate the costs to fill in mining pits utilizing a proprietary model to determine the volume of the pit.

Our AROs are adjusted on a regular basis to reflect the passage of time and to incorporate revisions to estimates and judgments including, planned plant retirement dates, amounts and timing of future cash expenditures, discount rates, cost escalation factors, market risk premiums, inflation rates, and if applicable, experience with government regulators regarding similar obligations.

See Note 13 to the Financial Statements for additional information.

Impairment of Goodwill and Other Long-Lived Assets

Goodwill and Intangible Assets with Indefinite Useful Lives

Goodwill and intangible assets with indefinite useful lives, such as the intangible asset related to the our retail trade names are not amortized and are subject to impairment testing annually, or when events or changes in the business environment indicate that the carrying value of the reporting unit may exceed its fair value. Evaluating goodwill and intangible assets with indefinite useful lives involves applying significant assumptions including discount rates, forecasted results for the applicable reporting unit and retail trade name, market multiples, and growth rates. These assumptions are forward looking and could be affected by future economic and market conditions.

Accounting standards allow a company to qualitatively assess if the carrying value of a reporting unit with goodwill and retail trade name intangible asset is more likely than not less than the fair value. If the entity determines the carrying value is not more likely greater than the fair value, no further testing for impairment is required. On the most recent testing date, we performed a qualitative assessment and determined that it was more likely than not that the fair value of our reporting units and retail trade names exceeded their carrying value. Significant qualitative factors were evaluated included reporting unit and trade name financial performance, market multiples, general macroeconomic, industry, and market conditions, cost factors, customer attrition, and interest rates. See Note 7 to the Financial Statements for additional information.

Long-Lived Assets

We evaluate long-lived assets (including intangible assets with finite lives) for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Indicators of impairment for our generation facilities include an expectation of continuing long-term declines in natural gas prices and/or Market Heat Rates, an expectation that "more likely than not" a generation asset will be sold or otherwise disposed of significantly before the end of its estimated useful life, or additional environmental regulations significantly decrease the cash flows expected from the associated assets. The determination of the existence of these and other indications of impairment involves judgments that are subjective in nature and may require the use of estimates in forecasting future results and cash flows given the diverse fuel mix and output rates of our generation asset groups. See Note 20 to the Financial Statements for additional information.

After identifying an indicator of impairment, recoverability of long-lived assets is determined by a comparison of the carrying amount of the long-lived asset group to the net cash flows expected to be generated by the asset group. Assumptions used in our estimate of net cash flows of the asset group include, forward natural gas and electricity prices, forward capacity prices, the effects of enacted environmental rules, generation plant performance, forecasted capital expenditures, forecasted fuel prices, and forecasted operating costs. The carrying value of such asset groups is determined to be unrecoverable if the projected undiscounted cash flows are less than the carrying value.

If an asset group carrying value is determined to be unrecoverable, fair value will be calculated based on a market participant view and a loss will be recorded for the amount the carrying value exceeds the fair value. Fair value is determined primarily by discounted cash flows (income approach) and supported by available market valuations, if applicable. The income approach involves estimates of future performance that reflect assumptions regarding, among other things, forward electricity prices, forward capacity prices, Market Heat Rates, the effects of enacted environmental rules, generation plant performance, forecasted capital expenditures, forecasted fuel prices, and the discount rate applied to the forecasted cash flows. Any significant change to one or more of these factors can have a material impact on the fair value measurement of our long-lived assets.

Nuclear PTC Revenues

Nuclear PTC revenues are accounted for by analogy to the grant model within International Accounting Standards 20, *Accounting for Government Grants and Disclosures of Government Assistance.* Nuclear PTC revenues are based on annual gross receipts generated from qualifying nuclear production in the calendar year. Treasury regulations are expected to further provide interpretive guidance on the definition of gross receipts over the next year. Given the lack of guidance to date, we recognized 2024 nuclear PTC revenues based on our best estimate and interpretation of gross receipts which includes settled spot energy revenues and capacity revenues at each nuclear unit, and excludes any hedges. Any interpretive guidance on the definition of gross receipts which differs from the interpretation used in our estimate could result in a material change to PTC revenues attributable to 2024 and would be reflected as a change in estimate in the period in which the guidance is received.

We have determined that we will meet the prevailing wage requirements at all our nuclear units and are eligible for the five times multiplier, which is reflected in the amount of nuclear PTC revenue recognized in 2024.

Results of Operations

Net income increased $1.32 billion to Net income of $2.812 billion for the year ended December 31, 2024 compared to the year ended December 31, 2023. For additional information see the following discussion of our results of operations.

EBITDA and Adjusted EBITDA

In analyzing and planning for our business, we supplement our use of GAAP financial measures with non-GAAP financial measures, including EBITDA and Adjusted EBITDA as performance measures. These non-GAAP financial measures reflect an additional way of viewing aspects of our business that, when viewed (i) with our GAAP results and (ii) the accompanying reconciliations to corresponding GAAP financial measures may provide a more complete understanding of factors and trends affecting our business. Because EBITDA and Adjusted EBITDA are financial measures that management uses to allocate resources, determine our ability to fund capital expenditures, assess performance against our peers, and evaluate overall financial performance, we believe they provide useful information for investors.

These non-GAAP financial measures should not be relied upon to the exclusion of GAAP financial measures and are, by definition, an incomplete understanding of Vistra and must be considered in conjunction with GAAP measures. In addition, non-GAAP financial measures are not standardized; therefore, it may not be possible to compare these financial measures with other companies' non-GAAP financial measures having the same or similar names. We strongly encourage investors to review the consolidated financial statements and publicly filed reports in their entirety and not rely on any single financial measure.

When EBITDA or Adjusted EBITDA is discussed in reference to performance on a consolidated basis, the most directly comparable GAAP financial measure to EBITDA and Adjusted EBITDA is Net income (loss).

Vistra Consolidated Financial Results — Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

The following table presents Net income (loss), EBITDA and Adjusted EBITDA for the year ended December 31, 2024:

	Year Ended December 31, 2024						
	Retail	Texas	East	West	Asset Closure	Eliminations / Corporate and Other	Vistra Consolidated
	(in millions)						
Operating revenues	$ 12,797	$ 5,394	$ 5,661	$ 877	$ 1	$ (7,506)	$ 17,224
Fuel, purchased power costs, and delivery fees	(10,276)	(1,596)	(2,698)	(221)	(3)	7,509	(7,285)
Operating costs	(159)	(996)	(1,103)	(72)	(81)	(3)	(2,414)
Depreciation and amortization	(114)	(581)	(996)	(86)	—	(66)	(1,843)
Selling, general, and administrative expenses	(977)	(169)	(148)	(25)	(43)	(239)	(1,601)
Operating income (loss)	1,271	2,052	716	473	(126)	(305)	4,081
Other income	1	39	181	3	16	72	312
Other deductions	(2)	(4)	(4)	(6)	(2)	(3)	(21)
Interest expense and related charges	(54)	46	9	1	(4)	(898)	(900)
Impacts of Tax Receivable Agreement	—	—	—	—	—	(5)	(5)
Income (loss) before income taxes	1,216	2,133	902	471	(116)	(1,139)	3,467
Income tax expense	—	—	—	—	—	(655)	(655)
Net income (loss)	**$ 1,216**	**$ 2,133**	**$ 902**	**$ 471**	**$ (116)**	**$ (1,794)**	**$ 2,812**
Income tax expense	—	—	—	—	—	655	655
Interest expense and related charges (a)	54	(46)	(9)	(1)	4	898	900
Depreciation and amortization (b)	114	686	1,278	86	—	66	2,230
EBITDA before Adjustments	1,384	2,773	2,171	556	(112)	(175)	6,597

	Year Ended December 31, 2024						
	Retail	Texas	East	West	Asset Closure	Eliminations / Corporate and Other	Vistra Consolidated
Unrealized net (gain) loss resulting from commodity hedging transactions	52	(790)	(76)	(332)	(9)	—	(1,155)
Purchase accounting impacts	—	1	(12)	—	—	(14)	(25)
Impacts of Tax Receivable Agreement (c)	—	—	—	—	—	(5)	(5)
Non-cash compensation expenses	—	—	—	—	—	100	100
Transition and merger expenses	2	1	22	—	—	111	136
Decommissioning-related activities (d)	—	26	(91)	2	—	—	(63)
ERP system implementation expenses	8	7	5	1	2	—	23
Other, net	17	14	(2)	11	2	(111)	(69)
Adjusted EBITDA	**$ 1,463**	**$ 2,032**	**$ 2,017**	**$ 238**	**$ (117)**	**$ (94)**	**$ 5,539**

(a) Includes $53 million of unrealized mark-to-market net gains on interest rate swaps.
(b) Includes nuclear fuel amortization of $105 million and $282 million, respectively, in the Texas and East segments.
(c) Includes $10 million gain recognized on the repurchase of TRA Rights in the year ended December 31, 2024.
(d) Represents net of all NDT (income) loss of the PJM nuclear facilities, ARO accretion expense for operating assets and ARO remeasurement impacts for operating assets.

For the year ended December 31, 2024, the Texas and East segments include nuclear PTC revenue estimates of $281 million and $264 million, respectively. See Note 4 to the Financial Statements for additional information.

The following table presents Net income (loss), EBITDA, and Adjusted EBITDA for the year ended December 31, 2023:

	Year Ended December 31, 2023						
	Retail	Texas	East	West	Asset Closure	Eliminations / Corporate and Other	Vistra Consolidated
	(in millions)						
Operating revenues	$ 10,572	$ 3,979	$ 5,890	$ 914	$ —	$ (6,576)	$ 14,779
Fuel, purchased power costs, and delivery fees	(9,046)	(2,028)	(2,730)	(328)	(3)	6,578	(7,557)
Operating costs	(123)	(917)	(528)	(58)	(74)	(2)	(1,702)
Depreciation and amortization	(102)	(550)	(703)	(79)	—	(68)	(1,502)
Selling, general, and administrative expenses	(858)	(140)	(127)	(24)	(34)	(125)	(1,308)
Impairment of long-lived assets	—	—	(49)	—	—	—	(49)
Operating income (loss)	443	344	1,753	425	(111)	(193)	2,661
Other income	1	35	4	21	110	86	257
Other deductions	—	(2)	(5)	—	—	(7)	(14)
Interest expense and related charges	(20)	21	(2)	8	(5)	(742)	(740)
Impacts of Tax Receivable Agreement	—	—	—	—	—	(164)	(164)
Income (loss) before income taxes	424	398	1,750	454	(6)	(1,020)	2,000
Income tax expense	—	—	(1)	—	—	(507)	(508)
Net income (loss)	**$ 424**	**$ 398**	**$ 1,749**	**$ 454**	**$ (6)**	**$ (1,527)**	**$ 1,492**
Income tax expense	—	—	1	—	—	507	508
Interest expense and related charges (a)	20	(21)	2	(8)	5	742	740
Depreciation and amortization (b)	102	641	703	79	—	68	1,593
EBITDA before Adjustments	546	1,018	2,455	525	(1)	(210)	4,333
Unrealized net (gain) loss resulting from commodity hedging transactions	586	813	(1,586)	(267)	(36)	—	(490)

	Year Ended December 31, 2023						
	Retail	Texas	East	West	Asset Closure	Eliminations / Corporate and Other	Vistra Consolidated
Impacts of Tax Receivable Agreement (c)	—	—	—	—	—	135	135
Non-cash compensation expenses	—	—	—	—	—	78	78
Transition and merger expenses	—	1	2	—	—	47	50
Impairment of long-lived assets	—	—	49	—	—	—	49
PJM capacity performance default impacts (d)	—	—	9	—	—	—	9
Winter Storm Uri impacts (e)	(52)	4	—	—	—	—	(48)
Other, net	25	(2)	72	5	(2)	(113)	(15)
Adjusted EBITDA	**$ 1,105**	**$ 1,834**	**$ 1,001**	**$ 263**	**$ (39)**	**$ (63)**	**$ 4,101**

(a) Includes $36 million of unrealized mark-to-market net losses on interest rate swaps.
(b) Includes nuclear fuel amortization of $91 million in the Texas segment.
(c) Includes $29 million gain recognized on the repurchase of TRA Rights in December 2023.
(d) Represents estimate of anticipated market participant defaults or settlements on initial PJM capacity performance penalties due to extreme magnitude of penalties associated with Winter Storm Elliott.
(e) Adjusted EBITDA impacts of Winter Storm Uri reflects the application of bill credits to large commercial and industrial customers that curtailed their usage during Winter Storm Uri and a reduction in the allocation of ERCOT default uplift charges which were expected to be paid over several decades under protocols existing at the time of the storm.

GAAP net income increased $1.32 billion to net income of $2.812 billion in the year ended December 31, 2024 compared to the year ended December 31, 2023. The primary drivers for the increase in GAAP net income include:

Favorable impacts:

- An increase of $665 million in unrealized mark-to-market gains on derivative positions due to power and natural gas forward market curves moving down more significantly in Texas relative to our hedge positions in the year ended December 31, 2024 as compared to the year ended December 31, 2023. See further information on our derivative results in *Energy-Related Commodity Contracts and Mark-to-Market Activities* below.
- Addition of Energy Harbor in March 2024 with results reflected in the East and Retail segments.
- An increase of $545 million in PTC revenues due to the nuclear PTC established by the IRA including $281 million and $264 million recognized in Texas and East, respectively. See Note 4 for additional information.
- An increase in retail income driven by an increase in customer counts and higher margins.
- Expiration of legacy Vistra default service contracts in the East segment which resulted in higher-than-expected migration of customers at rates below prevailing wholesale market prices in the year ended December 31, 2023.
- A decrease of approximately $160 million of accretion and remeasurement expenses associated with the TRA obligation driven by the acquisition of substantially all TRA rights between December 2023 and February 2024.

Unfavorable impacts:

- Increase in depreciation and amortization expense driven by addition of assets acquired from Energy Harbor and reflected in East.
- Increase in interest expense driven by higher average borrowings and unrealized mark to market losses on interest rate swaps.
- Increase in selling, general, and administrative expenses in Retail segment and Corp. and Other driven primarily by the addition of Energy Harbor.
- Increase in income tax expense driven by higher income.

	Year Ended December 31,							
	Retail		Texas		East		West	
	2024	2023	2024	2023	2024	2023	2024	2023
Retail electricity sales volumes (GWh):								
Sales volumes in ERCOT	74,295	70,275						
Sales volumes in Northeast/ Midwest	59,066	27,147						
Total retail electricity sales volumes	133,361	97,422						
Production volumes (GWh):								
Natural gas facilities			44,595	41,849	60,279	60,502	4,175	5,462
Lignite and coal facilities			23,307	26,559	16,938	13,912		
Nuclear facilities			19,670	18,893	26,540			
Solar facilities			757	781				
Capacity factors:								
CCGT facilities			58.1 %	55.1 %	62.0 %	62.2 %	46.5 %	61.0 %
Lignite and coal facilities			59.0 %	67.4 %	49.1 %	40.4 %		
Nuclear facilities			93.3 %	89.9 %	89.3 %			
Weather - percent of normal (a):								
Cooling degree days	112 %	115 %	112 %	112 %	103 %	96 %	90 %	79 %
Heating degree days	78 %	85 %	77 %	88 %	88 %	87 %	119 %	125 %

(a) Reflects cooling degree or heating degree days for the region based on Weather Services International (WSI) data. A degree day compares the average of the hourly outdoor temperatures during each day to a 65° Fahrenheit base temperature.

	Year Ended December 31,	
	2024	2023
Average Power Price ($MWh) (a):		
ERCOT North Hub	$ 25.89	$ 48.30
ERCOT West Hub	$ 27.45	$ 49.45
PJM AEP Dayton Hub	$ 30.74	$ 30.81
PJM Northern Illinois Hub	$ 25.46	$ 26.64
PJM Western Hub	$ 33.83	$ 33.07
MISO Indiana Hub	$ 31.36	$ 32.98
ISONE Massachusetts Hub	$ 41.47	$ 36.82
New York Zone A	$ 32.66	$ 25.68
CAISO NP15	$ 40.67	$ 61.37

	Year Ended December 31,	
	2024	2023
Average Natural gas price ($/MMBtu) (b):		
NYMEX Henry Hub	$ 2.25	$ 2.53
Houston Ship Channel	$ 1.87	$ 2.20
Permian Basin	$ 0.08	$ 1.53
Dominion South	$ 1.67	$ 1.63
Tetco ELA	$ 2.08	$ 2.27
Chicago Citygate	$ 2.12	$ 2.30
TetcoM3	$ 2.07	$ 1.90
Algonquin Citygates	$ 3.03	$ 2.94
PG&E Citygate	$ 3.09	$ 6.09

(a) Reflects the average around-the-clock settled prices for the periods presented and does not necessarily reflect prices we realized.
(b) Reflects the average around-the-clock settled prices for the periods presented and does not reflect costs incurred by us.

Adjusted EBITDA for the year ended December 31, 2024 compared to the year ended December 31, 2023 increased by $1.438 billion. The primary drivers for the increase include:

	Year Ended December 31, 2024 Compared to 2023			
	Retail (a)	Texas	East (a)	West
	(in millions)			
Favorable change in realized revenue net of fuel driven by addition of Energy Harbor, including nuclear PTC revenues from the acquired nuclear facilities and rolloff of negative margin defaults service contracts in East. Favorable change in Texas is driven by nuclear PTC revenues.	$ —	$ 257	$ 1,570	$ 6
Higher retail margins driven by favorable power supply costs, customer count growth and addition of energy Harbor retail contracts, including acquired default service contracts	425	—	—	—
Favorable impact of less Winter Storm Uri bill credits applied	42	—	—	—
Increase in plant operating costs due primarily to addition of Energy Harbor in East	—	(52)	(490)	(11)
Change in SG&A and other primarily due to increase in costs related to addition of Energy Harbor in Retail and East	(109)	(7)	(64)	(20)
Change in Adjusted EBITDA	**$ 358**	**$ 198**	**$ 1,016**	**$ (25)**
Increase in depreciation and amortization driven primarily by addition of Energy Harbor assets in East	(12)	(45)	(575)	(7)
Change in unrealized net gains (losses) on hedging activities (b)	534	1,603	(1,510)	65
Impairment of long-lived assets	—	—	49	—
Decommissioning related activities	—	(26)	91	(2)
PJM capacity performance default impacts	—	—	9	—
Winter Storm Uri impact	(52)	4	—	—
Other (including interest expenses)	(36)	1	73	(14)
Change in Net income	**$ 792**	**$ 1,735**	**$ (847)**	**$ 17**

(a) Includes amounts associated with operations acquired in the Energy Harbor Merger beginning March 1, 2024.
(b) See *Energy-Related Commodity Contracts and Mark-to-Market Activities* below for analysis of hedging strategy.

Asset Closure Segment — Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

	Year Ended December 31,		Favorable (Unfavorable) Change
	2024	2023	
	(in millions)		
Operating revenues	$ 1	$ —	$ 1
Fuel, purchased power costs, and delivery fees	(3)	(3)	—
Operating costs	(81)	(74)	(7)
Selling, general, and administrative expenses	(43)	(34)	(9)
Operating loss	(126)	(111)	(15)
Other income	16	110	(94)
Other deductions	(2)	—	(2)
Interest expense and related charges	(4)	(5)	1
Income (loss) before income taxes	(116)	(6)	(110)
Net loss	**$ (116)**	**$ (6)**	**$ (110)**
Adjusted EBITDA	**$ (117)**	**$ (39)**	**$ (78)**

GAAP and Adjusted EBITDA results for the year ended December 31, 2024 are unfavorable compared to the year ended December 31, 2023 primarily due to other income of $89 million from the gain on sale of property in Freestone County, Texas in 2023.

Energy-Related Commodity Contracts and Mark-to-Market Activities

We entered the 2023 and 2024 calendar years with more than 99% of our expected generation volumes hedged. While settled power prices in 2024 are lower than historical averages, the strategic hedging allowed us to lock in margins above what we would have been able to realize if unhedged and are higher than the margins from hedging for the year ended December 31, 2023, which is driving the increase in realized revenue net of fuel in the generation segments along with the addition of Energy Harbor. The forward power sales are also the drivers of the changes in unrealized gains/losses on hedging activities. As power prices increase/decrease in comparison to what our generation segments have sold forward, the generation segments recognize unrealized losses/gains. The retail segment procures power from the generation segments to serve future load obligations and thus changes in forward power prices have an inverse effect on unrealized mark to market for the retail segment as compared to the generation segments. In 2024, we saw a decrease in forward power prices in all our generation segments compared to our hedged positions which drove material unrealized gains in those segments, partially offset by unrealized losses in our retail segment. In 2023, the non-Texas generation segments also experienced a decrease in forward power prices compared to our hedged positions, which resulted in unrealized gains in those segments partially offset by unrealized losses in our retail segment. In the Texas segment, forward power prices materially increased in the year ended December 31, 2023, which resulted in unrealized losses partially offset by unrealized gains in the Retail segment.

The table below summarizes the changes in commodity contract assets and liabilities for the years ended December 31, 2024 and 2023. The net change in these assets and liabilities, excluding "other activity" as described below, reflects $1.155 billion and $490 million in unrealized net gains for the years ended December 31, 2024 and 2023, respectively, arising from mark-to-market accounting for positions in the commodity contract portfolio.

	Year Ended December 31, 2024	Year Ended December 31, 2023
	(in millions)	
Commodity contract net liability as of January 1	$ (2,740)	$ (3,148)
Settlements/termination of positions (a)	1,213	1,643
Changes in fair value of positions in the portfolio (b)	(58)	(1,153)
Acquired commodity contracts (c)	(50)	—
Other activity (d)	175	(82)
Commodity contract net liability as of December 31	$ (1,460)	$ (2,740)

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(a) Represents reversals of previously recognized unrealized gains and losses upon settlement/termination (offsets realized gains/(losses) recognized in the settlement period). Excludes changes in fair value in the month the position settled as well as amounts related to positions entered into, and settled, in the same month.

(b) Represents unrealized net gains/(losses) recognized, reflecting the effect of changes in fair value. Excludes changes in fair value in the month the position settled as well as amounts related to positions entered into, and settled, in the same month.

(c) Includes fair value of commodity contracts acquired in the Energy Harbor Merger (see Note 2 to the Financial Statements).

(d) Primarily represents changes in fair value of positions due to receipt or payment of cash not reflected in unrealized gains or losses. Amounts are generally related to premiums related to options purchased or sold as well as certain margin deposits classified as settlement for certain transactions executed on the CME.

The following maturity table presents the net commodity contract liability arising from recognition of fair values as of December 31, 2024, scheduled by the source of fair value and contractual settlement dates of the underlying positions.

	Maturity dates of unrealized commodity contract net liability as of December 31, 2024				
Source of Fair Value	Less than 1 year	1-3 years	4-5 years	Excess of 5 years	Total
			(in millions)		
Prices actively quoted	$ (205)	$ 11	$ (1)	$ —	$ (195)
Prices provided by other external sources	(423)	(91)	1	—	(513)
Prices based on models	(162)	(507)	(75)	(8)	(752)
Total	$ (790)	$ (587)	$ (75)	$ (8)	$ (1,460)

We have engaged in natural gas hedging activities to mitigate the risk of higher or lower wholesale electricity prices that have corresponded to increases or declines in natural gas prices. When natural gas prices are elevated or depressed, we continue to seek opportunities to manage our wholesale power price exposure through hedging activities, including forward wholesale and retail electricity sales.

Estimated hedging levels for generation volumes in our Texas, East and West segments as of December 31, 2024 were as follows:

	2025	2026
Nuclear/Renewable/Coal Generation:		
Texas	100 %	100 %
East	84 %	55 %
Natural Gas Generation:		
Texas	100 %	57 %
East	100 %	77 %
West	100 %	37 %

Financial Condition

Cash Flows

Operating Cash Flows

Cash provided by operating activities totaled $4.563 billion and $5.453 billion for the years ended December 31, 2024 and 2023, respectively. The unfavorable change of $890 million was primarily driven by $1.06 billion less of a decrease in net margin deposits (returns of cash deposits related to commodity contracts which support our hedging strategy) in the year ended December 31, 2024 as compared to the year ended December 31, 2023. The unfavorable change in margin deposits is partially offset by an increase in cash from realized operating income primarily due to the addition of Energy Harbor.

Depreciation and amortization — Depreciation and amortization expense, as reported as a reconciling adjustment in the consolidated statements of cash flows, exceeded the amount reported in the consolidated statements of operations by $788 million, $454 million, and $451 million for the years ended December 31, 2024, 2023, and 2022, respectively. This difference represents amortization of nuclear fuel, which is reported as fuel costs in the consolidated statements of operations consistent with industry practice, as well as the amortization of intangible net assets and liabilities. These are reported under various other line items in the consolidated statements of operations, including operating revenues, fuel and purchased power costs, and delivery fees (see Note 7 to the Financial Statements).

Investing Cash Flows

Cash used in investing activities totaled $5.276 billion and $2.145 billion for the years ended December 31, 2024 and 2023, respectively. The increase of $3.131 billion was driven primarily by the $3.1 billion used to fund the Energy Harbor Merger.

	Year Ended December 31, 2024	Year Ended December 31, 2023	Increase (Decrease)
	(in millions)		
Capital expenditures, including LTSA prepayments	$ (801)	$ (764)	(37)
Nuclear fuel purchases	(477)	(214)	(263)
Growth and development expenditures	(800)	(698)	(102)
Total capital expenditures	(2,078)	(1,676)	(402)
Energy Harbor acquisition (net of cash acquired)	(3,065)	—	(3,065)
Net sales (purchases) of environmental allowances	(453)	(571)	118
Net sales of (investments in) nuclear decommissioning trust fund securities	(23)	(23)	0
Proceeds from sales of property, plant, and equipment, including nuclear fuel	196	115	81
Proceeds from sales of transferable ITCs	150	—	150
Other investing activity	(3)	10	(13)
Cash used in investing activities	$ (5,276)	$ (2,145)	$ (3,131)

Financing Cash Flows

Cash used in financing activities totaled $1.604 billion and $294 million for the year ended December 31, 2024 and 2023, respectively. The increase of $1.31 billion was primarily driven by the $1.748 billion paid to Avenue and Nuveen in connection with the purchase of their noncontrolling interests in Vistra Vision and the $180 million of dividends we paid to them. These cash outflows were partially offset by an $890 million increase in net new borrowings, as detailed below.

	Year Ended December 31, 2024	Year Ended December 31, 2023	Increase (Decrease)
	(in millions)		
Share repurchases	$ (1,266)	$ (1,245)	$ (21)
Issuances of long-term debt	3,817	2,498	1,319
Other net long-term borrowings (repayments)	(2,287)	(33)	(2,254)
Net short-term borrowings (repayments)	—	(650)	650
Net borrowings (repayments) under the accounts receivable financing facilities	750	(425)	1,175
Dividends paid to common stockholders	(305)	(313)	8
Dividends paid to preferred stockholders	(173)	(150)	(23)
Dividends paid to noncontrolling and redeemable noncontrolling interest holders	(180)	—	(180)
Payment for acquisition of noncontrolling interest	(1,748)	—	(1,748)
TRA Repurchase and tender offer — return of capital	(122)	—	(122)
Other financing activity	(90)	24	(114)
Cash used in financing activities	$ (1,604)	$ (294)	$ (1,310)

Debt Activity

We remain committed to a strong balance sheet and have continued to state our objective to reduce consolidated net leverage. We also intend to maintain adequate liquidity and pursue opportunities to refinance our long-term debt to extend maturities.

In May 2025, $744 million of 5.125% Senior Secured Notes will reach maturity. We plan to fund this upcoming principal payment using a combination of proceeds from the senior secured notes issued in December 2024 and cash on hand. Increases in interest rates have resulted in, and will likely continue to result in, increased borrowing costs.

See Note 9 to the Financial Statements for additional information.

Available Liquidity

The following table summarizes changes in available liquidity for the year ended December 31, 2024:

	December 31, 2024	December 31, 2023	Change
		(in millions)	
Cash and cash equivalents (a)	$ 1,188	$ 3,485	$ (2,297)
Vistra Operations Credit Facilities — Revolving Credit Facility (b)	2,162	1,213	949
Vistra Operations — Commodity-Linked Facility (c)	771	1,101	(330)
Total available liquidity (d)(e)	$ 4,121	$ 5,799	$ (1,678)

(a) See the consolidated statements of cash flows in the Financial Statements and *Cash Flows* above for details of the decrease in cash and cash equivalents for the year ended December 31, 2024. The decrease includes $3.1 billion that was used to fund the Energy Harbor Merger.
(b) The increase in availability for the year ended December 31, 2024 was driven by a $684 million decrease in letters of credit outstanding under the facility and the October 2024 amendment to the Revolving Credit Facility which, among other things, increased the revolving credit commitments by $265 million (see Note 9 to the Financial Statements).
(c) As of December 31, 2024 and 2023, the borrowing bases were less than the facility limits of $1.75 billion and $1.575 billion, respectively. As of December 31, 2024, available capacity reflects the borrowing base of $771 million and no cash borrowings. As of December 31, 2023, available capacity reflects the borrowing base of $1.101 billion and no cash borrowings.
(d) Excludes amounts available to be borrowed under the Receivables Facility and the Repurchase Facility, respectively. See Note 9 to the Financial Statements for additional information.
(e) Excludes any additional letters of credit that may be issued under the Secured LOC Facilities or the Alternative LOC Facilities. See Note 9 to the Financial Statements for additional information.

We believe that we will have access to sufficient liquidity to fund our anticipated cash requirements through at least the next 12 months, including the upcoming payments associated with the acquisition of Nuveen's noncontrolling interest in Vistra Vision discussed in Note 9 to the Financial Statements. Our operational cash flows tend to be seasonal and weighted toward the second half of the year.

Interest payments on long-term debt, after taking into account interest rate swaps, are expected to total approximately $905 million in 2025, $1.595 billion in 2026-2027, $1.180 billion in 2028-2029 and $1.305 billion thereafter. See Note 9 to the Financial Statements for additional information.

Our obligations under commodity purchase and services agreements, including capacity payments, nuclear fuel and natural gas take-or-pay contracts, coal contracts, business services and nuclear-related outsourcing and other purchase commitments, are expected to total approximately $3.270 billion in 2025, $2.650 billion in 2026-2027, $1.490 billion in 2028-2029 and $450 million thereafter. See Notes 10 and 15 to the Financial Statements for additional information.

Capital Expenditures

Estimated 2025 capital expenditures and nuclear fuel purchases as of December 31, 2024 total approximately $2.275 billion and include:

- $925 million for investments in generation and mining facilities;
- $725 million for solar and energy storage development;
- $300 million for nuclear fuel purchases; and
- $325 million for other growth expenditures.

Liquidity Effects of Commodity Hedging and Trading Activities

We have entered into commodity hedging and trading transactions that require us to post collateral if the forward price of the underlying commodity moves such that the hedging or trading instrument we hold has declined in value. We use cash, letters of credit, Eligible Assets (see Note 8 to the Financial Statements) and other forms of credit support to satisfy such collateral posting obligations. See Note 9 to the Financial Statements for additional information.

Exchange cleared transactions typically require initial margin (*i.e.*, the upfront cash and/or letter of credit posted to take into account the size and maturity of the positions and credit quality) in addition to variation margin (*i.e.*, the daily cash margin posted to take into account changes in the value of the underlying commodity). The amount of initial margin required is generally defined by exchange rules. Clearing agents, however, typically have the right to request additional initial margin based on various factors, including market depth, volatility and credit quality, which may be in the form of cash, letters of credit, a guaranty or other forms as negotiated with the clearing agent. Cash collateral received from counterparties is either used for working capital and other business purposes, including reducing borrowings under credit facilities, or is required to be deposited in a separate account and restricted from being used for working capital and other corporate purposes. With respect to over-the-counter transactions, counterparties generally have the right to substitute letters of credit for such cash collateral. In such event, the cash collateral previously posted would be returned to such counterparties, which would reduce liquidity in the event the cash was not restricted.

As of December 31, 2024, we received or posted cash, letters of credit and Eligible Assets for commodity hedging and trading activities as follows:

- $841 million in cash and Eligible Assets has been posted with counterparties as compared to $1.244 billion posted as of December 31, 2023;
- $49 million in cash has been received from counterparties as compared to $45 million received as of December 31, 2023;
- $2.560 billion in letters of credit have been posted with counterparties as compared to $2.408 billion posted as of December 31, 2023; and
- $131 million in letters of credit have been received from counterparties as compared to $143 million received as of December 31, 2023.

See *Collateral Support Obligations* below for information related to collateral posted in accordance with the PUCT and ISO/RTO rules.

Income Tax Payments

In the next 12 months, we expect to make approximately $31 million in federal income tax payments, $81 million in state income tax payments and $2 million in TRA payments, offset by $14 million in state tax refunds.

For the year ended December 31, 2024, there were $5 million federal income tax payments, $59 million in state income tax payments, $9 million in state income tax refunds and no TRA payments.

Capitalization

Our capitalization ratios consisted of 73% and 70% long-term debt (less amounts due currently) and 27% and 30% stockholders' equity at December 31, 2024 and 2023, respectively. Total long-term debt (including amounts due currently) to capitalization was 75% and 73% at December 31, 2024 and 2023, respectively.

Financial Covenants

The Vistra Operations Credit Agreement and the Vistra Operations Commodity-Linked Credit Agreement each includes a covenant, solely with respect to the Revolving Credit Facility and the Commodity-Linked Facility and solely during a compliance period (which, in general, is applicable when the aggregate revolving borrowings and revolving letters of credit outstanding (excluding all undrawn revolving letters of credit and cash collateralized backstopped revolving letters of credit) exceed 35% of the revolving commitments), that requires the consolidated first-lien net leverage ratio not to exceed 4.25 to 1.00 (or, during a collateral suspension period, the consolidated total net leverage ratio not to exceed 5.50 to 1.00). In addition, each of the Secured LOC Facilities includes a covenant that requires the consolidated first-lien net leverage ratio not to exceed 4.25 to 1.00 (or, for certain facilities that include a collateral suspension mechanism, during a collateral suspension period, the consolidated total net leverage ratio not to exceed 5.50 to 1.00). Although the period ended December 31, 2024 was not a compliance period, we would have been in compliance with the Vistra Operations Credit Agreement, Vistra Operations Commodity-Linked Credit Agreement and Secured LOC Facilities financial covenants if they were required to be tested at such time. See Note 9 to the Financial Statements for additional information.

Collateral Support Obligations

The RCT has rules in place to assure that parties can meet their mining reclamation obligations. In September 2016, the RCT agreed to a collateral bond of up to $975 million to support Luminant's reclamation obligations. The collateral bond is effectively a first lien on all of Vistra Operations' assets (which ranks pari passu with the Vistra Operations Credit Facilities) that contractually enables the RCT to be paid (up to $975 million) before the other first-lien lenders in the event of a liquidation of our assets. Collateral support relates to land mined or being mined and not yet reclaimed as well as land for which permits have been obtained but mining activities have not yet begun and land already reclaimed but not released from regulatory obligations by the RCT, and includes cost contingency amounts.

The PUCT has rules in place to assure adequate creditworthiness of each REP, including the ability to return customer deposits, if necessary. Under these rules, as of December 31, 2024, Vistra has posted letters of credit in the amount of $86 million with the PUCT, which is subject to adjustments.

The ISOs/RTOs we operate in have rules in place to assure adequate creditworthiness of parties that participate in the markets operated by those ISOs/RTOs. Under these rules, Vistra has posted collateral support totaling $960 million in the form of letters of credit, $70 million in the form of a surety bond and $3 million of cash as of December 31, 2024 (which is subject to daily adjustments based on settlement activity with the ISOs/RTOs).

Material Cross Default/Acceleration Provisions

Certain of our contractual arrangements contain provisions that could result in an event of default if there were a failure under financing arrangements to meet payment terms or to observe covenants that could result in an acceleration of payments due. Such provisions are referred to as "cross default" or "cross acceleration" provisions.

A default by Vistra Operations or any of its restricted subsidiaries in respect of certain specified indebtedness in an aggregate amount in excess of the greatest of $1.0 billion, 17.5% of Consolidated EBITDA and 2.50% of Consolidated Total Assets, may result in a cross default under the Vistra Operations Credit Facilities and the Commodity-Linked Facility. Such a default would allow the lenders under each such facility to accelerate the maturity of outstanding balances under such facilities, which totaled approximately $2.475 billion and zero, respectively, as of December 31, 2024.

Each of Vistra Operations' (or its subsidiaries') commodity hedging agreements and interest rate swap agreements that are secured with a lien on its assets on a pari passu basis with the Vistra Operations Credit Facilities lenders contains a cross-default provision. An event of a default by Vistra Operations or any of its subsidiaries relating to indebtedness equal to or above a threshold defined in the applicable agreement that results in the acceleration of such debt, would give such counterparty under these hedging agreements the right to terminate its hedge or interest rate swap agreement with Vistra Operations (or its applicable subsidiary) and require all outstanding obligations under such agreement to be settled.

Under the Vistra Operations Senior Unsecured Indentures, the Vistra Operations Senior Secured Indenture and the Indenture governing the 7.233% Senior Secured Notes, a default under any document evidencing indebtedness for borrowed money by Vistra Operations or any Guarantor Subsidiary for failure to pay principal when due at final maturity or that results in the acceleration of such indebtedness in an aggregate amount of $300 million or more may result in a cross default under the Vistra Operations Senior Unsecured Notes, the Senior Secured Notes, the 7.233% Senior Secured Notes, the Vistra Operations Credit Facilities, the Receivables Facility, the Commodity-Linked Facility and other current or future documents evidencing any indebtedness for borrowed money by the applicable borrower or issuer, as the case may be, and the applicable Guarantor Subsidiaries party thereto.

Additionally, we enter into energy-related physical and financial contracts, the master forms of which contain provisions whereby an event of default or acceleration of settlement would occur if we were to default under an obligation in respect of borrowings in excess of thresholds, which may vary by contract.

The Receivables Facility contains a cross-default provision. The cross-default provision applies, among other instances, if TXU Energy, Dynegy Energy Services, Ambit Texas, Value Based Brands, Energy Harbor LLC, TriEagle Energy, each indirect subsidiaries of Vistra and originators under the Receivables Facility (Originators), and Vistra or any of their respective subsidiaries fails to make a payment of principal or interest on any indebtedness that is outstanding in a principal amount of at least $300 million, in the case of Vistra Operations, and in a principal amount of at least $50 million, in the case of TXU Energy or any of the other Originators, after the expiration of any applicable grace period, or if other events occur or circumstances exist under such indebtedness which give rise to a right of the debtholder to accelerate such indebtedness, or if such indebtedness becomes due before its stated maturity. If this cross-default provision is triggered, a termination event under the Receivables Facility would occur and the Receivables Facility may be terminated.

The Repurchase Facility contains a cross-default provision. The cross-default provision applies, among other instances, if an event of default (or similar event) occurs under the Receivables Facility or the Vistra Operations Credit Facilities. If this cross-default provision is triggered, a termination event under the Repurchase Facility would occur and the Repurchase Facility may be terminated.

Under the Secured LOC Facilities, a default by Vistra Operations or any of its restricted subsidiaries in respect of certain specified indebtedness in an aggregate amount in excess of $300 million may result in a cross default under the Secured LOC Facilities. In addition, a default under any document evidencing indebtedness for borrowed money by Vistra Operations or any Guarantor Subsidiary for failure to pay principal when due at final maturity or that results in the acceleration of such indebtedness in an aggregate amount of $300 million or more, may result in a termination of the Secured LOC Facilities.

Under the Alternative LOC Facilities, a default by Vistra Operations or any of its restricted subsidiaries in respect of certain specified indebtedness in an aggregate amount in excess of the greater of $300 million and 17.5% of Consolidated EBITDA may result in a cross default under the Alternative LOC Facilities. In addition, a default under any document evidencing indebtedness for borrowed money by Vistra Operations or any Guarantor Subsidiary for failure to pay principal when due at final maturity or that results in the acceleration of such indebtedness in an aggregate amount exceeding the threshold above, may result in a termination of the Alternative LOC Facilities.

Under the Vistra Operations Senior Unsecured Indenture and the Vistra Operations Senior Secured Indenture governing the 7.750% Senior Unsecured Notes, the 6.875% Senior Unsecured Notes, the 6.950% Senior Secured Notes and the 6.000% Senior Secured Notes, a default under any document evidencing indebtedness for borrowed money by Vistra Operations or any Guarantor Subsidiary for failure to pay principal when due at final maturity or that results in the acceleration of such indebtedness in an aggregate amount that exceeds the greater of 1.5% of total assets and $600 million may result in a cross default under the respective notes and other current or future documents evidencing any indebtedness for borrowed money by the applicable borrower or issuer, as the case may be, and the applicable Guarantor Subsidiaries party thereto.

A default by Vistra Zero Operations or any of its restricted subsidiaries in respect of certain specified indebtedness in an aggregate amount in excess of the greatest of $100 million, 75% of Consolidated EBITDA and 6% of Consolidated Total Assets, may result in a cross default under the Vistra Zero Credit Agreement. Such a default would allow the lenders under such facility to accelerate the maturity of outstanding balances under such facility, which totaled approximately $697 million as of December 31, 2024.

A default by BCOP or any of its subsidiary guarantors in respect of certain provisions defined in the applicable agreement may result in a cross default under the BCOP Credit Agreement. Such a default would allow the lenders under such facility to accelerate the maturity of outstanding balances under such facility. In addition, the interest rate swap agreements that are secured with a lien on BCOP and its subsidiary guarantors' assets on a pari passu basis with the BCOP Credit Agreement contain cross-default provisions, where an event of a default by BCOP or any of its subsidiary guarantors that results in the acceleration of such debt, would give such counterparty under these hedging agreements the right to terminate its hedge or interest rate swap agreement with BCOP and require all outstanding obligations under such agreement to be settled.

Under the Nuveen UPA, a default under any document evidencing indebtedness for borrowed money by Vistra Operations or any Guarantor Subsidiary that results in the acceleration of such indebtedness in an aggregate amount that exceeds the greater of 1.5% of total assets and $600 million may result in a cross default under the UPA. Such a default would result in the payment obligations under the Nuveen UPA of Vistra Vision Holdings and/or any guarantor thereunder becoming immediately due and payable.

Guarantees

See Note 15 to the Financial Statements for additional information.

Commitments and Contingencies

See Note 15 to the Financial Statements for additional information.

Changes in Accounting Standards

See Note 1 to the Financial Statements for additional information.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In the normal course of business, our financial position is routinely subject to a variety of risks, including market risks associated with (i) changes in commodity prices, (ii) interest rate movements on outstanding debt, and (iii) credit risk, which is the risk of financial loss if a customer, counterparty, or financial institution is unable to perform or pay amounts due to us.

Market risks are monitored by our risk management group which operates independently of the wholesale commercial operations, utilizing defined practices and analytical methodologies. These practices and methodologies measure the risk of change in value of the portfolio of contracts and the hypothetical effect on this value from changes in market conditions. Measurement techniques include, but are not limited to, position reporting and review, Value at Risk (VaR) methodologies and stress test scenarios. Risk management regularly reports their analysis to the Company's Risk Committee and Executive Committee, and to the Sustainability and Risk Committee of the Board of Directors.

Commodity Price Risk and Oversight

Our business is subject to the inherent risks of market fluctuations in the price of commodities for energy-related products we market or purchase in futures markets including electricity, natural gas, uranium, coal, environmental credits and other energy commodities in competitive wholesale markets. Factors that influence these market fluctuations are dependent upon many factors outside of our control including seasonal changes in supply and demand, weather conditions, market liquidity, governmental, regulatory, and environmental policies.

We manage the commodity price and commodity-related operational risk related to the competitive energy business within limitations established by senior management and in accordance with overall risk management policies. In managing commodity price risk, we enter into a variety of market transactions including, but not limited to, short- and long-term contracts for physical delivery, exchange-traded and over-the-counter financial contracts and bilateral contracts with customers. Similar to other participants in the market, we cannot fully manage the long-term value impact of structural declines or increases in natural gas and power prices. Beginning in 2024, our nuclear fleet is eligible for the nuclear PTC provided by the IRA which provides increasing levels of support as unit revenues decline below levels established in the IRA and is further adjusted annually for inflation over the duration of the program.

VaR Methodology

A VaR methodology is used to measure the amount of market risk that exists within the portfolio under a variety of market conditions. The resultant VaR produces an estimate of a portfolio's potential for loss given a specified confidence level and considers, among other things, market movements utilizing standard statistical techniques given historical and projected market prices and volatilities.

Parametric processes are used to calculate VaR and are considered by management to be the most effective way to estimate changes in a portfolio's value based on assumed market conditions for liquid markets. This measurement estimates the potential loss in value, due to changes in market conditions, of all underlying generation assets and contracts. The use of this method requires a number of key assumptions, such as use of (i) an assumed confidence level, (ii) an assumed holding period (*i.e.*, the time necessary for management action, such as to liquidate positions), and (iii) historical estimates of volatility and correlation data.

The following table summarizes the VaR for Vistra's commodity portfolio based on a 95% confidence level and an assumed holding period of 60 days. Average VaRs as of December 31 are the average of each month-end average for the years ended December 31, 2024 and 2023, respectively:

	Year Ended December 31,	
	2024	2023
Average VaR	$ 236	$ 190
High VaR	$ 371	$ 423
Low VaR	$ 86	$ 115

The month-end average VaR risk measure increased in 2024 due to higher volumes following the Energy Harbor Merger.

Interest Rate Risk

We are exposed to fluctuations in interest rates through our issuance of variable rate debt. We mitigate our exposure to fluctuations in interest rates through entering interest rate swaps. These interest rate swaps limit the impact of interest rate changes on our results of operations and cash flows and to lower our overall borrowing costs. Interest rate risk is managed centrally by our treasury function.

As of December 31, 2024, we have approximately $3.5 billion principal amount of variable rate debt consisting of the Vistra Operations Credit Facilities Term Loan B-3 Facility, the BCOP Credit Facilities and the Vistra Zero Term Loan B Facility (see Note 9 to the Financial Statements). We have entered into net notional interest rate swaps that will hedge $2.3 billion of our exposure to variable rate debt through December 2030 (see Note 11 to Financial Statements). As of December 31, 2024, the potential reduction of annual pretax earnings over the next twelve months due to a one percentage-point (100 basis points) increase in floating interest rates on long-term debt totaled approximately $12 million after taking into account the interest rate swaps.

Credit Risk

Our primary concentration of credit risk is associated with the collection of receivables resulting from sales to retail customers and the risk of a counterparty's failure to meet its obligations under derivative contracts. We minimize our exposure to credit risk by evaluating potential counterparties, monitoring ongoing counterparty risk and assessing overall portfolio risk. This includes review of counterparty financial condition, current and potential credit exposures, credit rating and other quantitative and qualitative credit criteria. We also employ certain risk mitigation practices, including utilization of standardized master agreements that provide for netting and setoff rights, as well as credit enhancements such as margin deposits and customer deposits, letters of credit, parental guarantees and surety bonds. See Note 11 to the Financial Statements for additional information.

Our gross credit exposure (excluding collateral impacts) associated with retail and wholesale trade accounts receivable and net derivative assets arising from commodity contracts and hedging and trading activities totaled $2.360 billion at December 31, 2024. Including collateral posted to us by counterparties, our net exposure was $2.166 billion, as seen in the following table that presents the distribution of credit exposure by counterparty credit quality as of December 31, 2024. Credit collateral includes cash and letters of credit but excludes other credit enhancements such as guarantees or liens on assets.

	Exposure Before Credit Collateral				
	Trade Accounts Receivable	Derivatives	Gross Exposure	Credit Collateral	Net Exposure
			(in millions)		
Retail segment	$ 1,545	$ —	$ 1,545	$ 51	$ 1,494
Texas, East and Asset Closure segments:					
Investment grade	$ 99	$ 451	$ 550	$ 49	$ 501
Below investment grade or no rating	69	196	265	94	171
Texas, East and Asset Closure segments	$ 168	$ 647	$ 815	$ 143	$ 672
Totals	$ 1,713	$ 647	$ 2,360	$ 194	$ 2,166

Contracts classified as "normal" purchase or sale and non-derivative contractual commitments are not marked-to-market in the financial statements and are excluded from the detail above. Such contractual commitments may contain pricing that is favorable considering current market conditions and therefore represent economic risk if the counterparties do not perform.

An event of default by one or more counterparties could subsequently result in termination-related settlement payments that reduce available liquidity if amounts such as margin deposits are owed to the counterparties or delays in receipts of expected settlements owed to us. Significant (*i.e.*, 10% or greater) concentration of credit exposure exists with one counterparty, which represented an aggregate $262 million, or 39%, of our total net exposure as of December 31, 2024. We view exposure to this counterparty to be within an acceptable level of risk tolerance due to the counterparty's credit ratings, the counterparty's market role and deemed creditworthiness and the importance of our business relationship with the counterparty.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Vistra Corp.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Vistra Corp. and subsidiaries (the "Company") as of December 31, 2024 and 2023, the related consolidated statements of operations, comprehensive income (loss), cash flows, and changes in equity, for each of the three years in the period ended December 31, 2024, and the related notes and the schedule listed in the Index at Item 15(b) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2025, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matters

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

Fair Value Measurements — Certain Complex Level 3 Derivative Assets and Liabilities — Refer to Notes 1 and 12 to the financial statements

Critical Audit Matter Description

The Company has derivative assets and liabilities whose fair values are based on complex proprietary models and/or unobservable inputs. These financial instruments can span a broad array of contract types, some of which include especially complex valuations due to unique contract terms and significant judgement by management in estimating prices or volumes, including (1) power purchases and sales that include power and heat rate positions; (2) physical power and natural gas options and swaptions; (3) forward purchase contracts for congestion revenue rights; and (4) retail sales contracts. Under accounting principles generally accepted in the United States of America, these financial instruments are generally classified as Level 3 derivative assets or liabilities.

Given management uses complex proprietary models and/or unobservable inputs to estimate the fair value of the aforementioned Level 3 derivative assets and liabilities, performing audit procedures to evaluate the reasonableness of the fair value of Level 3 derivative assets and liabilities required a high degree of auditor judgment and an increased extent of effort, including the need to involve our energy commodity fair value specialists who possess significant quantitative and modeling expertise.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the evaluation of the fair value of Level 3 derivative assets and liabilities included the following, among others:

- We tested the effectiveness of internal control over derivative asset and liability valuations, including internal control related to appropriate application of illiquid price curves and other significant unobservable valuation inputs.
- We obtained the Company's complete listing of derivative assets and liabilities and related fair values as of December 31, 2024, to obtain an understanding of the types of instruments outstanding.
- We assessed the consistency by which management has applied illiquid price curves and significant unobservable valuation inputs.
- With the assistance of our energy commodity fair value specialists, we developed independent estimates of the fair value of a sample of Level 3 derivative instruments and compared our estimates to the Company's estimates.

Energy Harbor Holdings LLC Acquisition — Refer to Note 2 to the financial statements

Critical Audit Matter Description

The Company completed the acquisition of Energy Harbor Holdings LLC (formerly known as Energy Harbor Corp., “Energy Harbor”) for cash consideration of $3.1 billion and granting a 15% minority interest in certain Vistra businesses with a fair value estimated at $1.5 billion (collectively, the “purchase price consideration”) on March 1, 2024. The Company accounted for the acquisition of Energy Harbor as a business combination. Accordingly, the excess of the purchase price consideration over the identifiable assets acquired and liabilities assumed, was recorded as goodwill.

In connection with the business combination, the Company recorded $5.6 billion in property, plant and equipment, which includes the value of the three nuclear power plants. Additionally, a portion of the purchase price consideration also included the fair value of a 15% minority interest in Vistra’s nuclear power plant. The nuclear power plants were valued using a combination of an income approach and a market approach. The income approach utilized a discounted cash flow analysis based upon a debt-free cash flow model. The determination of the discounted cash flow model fair value of the nuclear plants included significant judgment and assumptions by management, including future commodity prices, earned production tax credits, anticipated production volumes, future operating costs and capital expenditures, and the discount rate applied to the nuclear plant cash flows.

Given the valuation of the nuclear power plants involved complex and subjective estimates of forecasted future growth and financial performance, performing audit procedures to evaluate the reasonableness of the valuation required a high degree of auditor judgment and an increased extent of effort, including the need to involve our fair value specialists who possess specialized skills and knowledge in modeling the fair value of long term assets.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the evaluation of the fair value of the nuclear power plants included the following, among others:

- We tested the effectiveness of internal control over the nuclear power plant valuations, including internal control related to the appropriateness of significant assumptions that are inputs to the fair value calculation and management's review of the valuation model.
- We obtained and read the third-party valuation report and evaluated the competency of the third-party specialist engaged by management to perform the valuations.
- With the assistance of our fair value specialists, we evaluated the appropriateness of management’s methodology, significant assumptions used to develop the fair value estimate, including the reasonableness of the discount cash flow model itself, the discount rate, present value factor, terminal value, and the internal rate of return, and tested the mathematical accuracy of the calculation.

- We evaluated the completeness and accuracy of the underlying data used to develop the forecasts of future cash flows, including assessing the reasonableness of the key assumptions.

/s/ Deloitte & Touche LLP

Dallas, Texas
February 27, 2025

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

VISTRA CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Millions of Dollars, Except Share Data)

	Year Ended December 31,		
	2024	2023	2022
Operating revenues	$ 17,224	$ 14,779	$ 13,728
Fuel, purchased power costs, and delivery fees	(7,285)	(7,557)	(10,401)
Operating costs	(2,414)	(1,702)	(1,645)
Depreciation and amortization	(1,843)	(1,502)	(1,596)
Selling, general, and administrative expenses	(1,601)	(1,308)	(1,189)
Impairment of long-lived and other assets	—	(49)	(74)
Operating income (loss)	4,081	2,661	(1,177)
Other income	312	257	117
Other deductions	(21)	(14)	(4)
Interest expense and related charges	(900)	(740)	(368)
Impacts of Tax Receivable Agreement	(5)	(164)	(128)
Net income (loss) before income taxes	3,467	2,000	(1,560)
Income tax (expense) benefit	(655)	(508)	350
Net income (loss)	2,812	1,492	(1,210)
Net (income) loss attributable to noncontrolling interest and redeemable noncontrolling interest	(153)	1	(17)
Net income (loss) attributable to Vistra	2,659	1,493	(1,227)
Cumulative dividends attributable to preferred stock	(192)	(150)	(150)
Net income (loss) attributable to Vistra common stock	$ 2,467	$ 1,343	$ (1,377)
Weighted average shares of common stock outstanding:			
Basic	344,788,634	369,771,359	422,447,074
Diluted	352,567,060	375,193,110	422,447,074
Net income (loss) per weighted average share of common stock outstanding:			
Basic	$ 7.16	$ 3.63	$ (3.26)
Diluted	$ 7.00	$ 3.58	$ (3.26)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Millions of Dollars)

	Year Ended December 31,		
	2024	2023	2022
Net income (loss)	$ 2,812	$ 1,492	$ (1,210)
Other comprehensive income (loss), net of tax effects:			
Effects related to pension and other retirement benefit obligations (net of tax expense of $4, $— and $7)	14	(1)	23
Total other comprehensive income (loss)	14	(1)	23
Comprehensive income (loss)	2,826	1,491	(1,187)
Comprehensive (income) loss attributable to noncontrolling interest and redeemable noncontrolling interest	(153)	1	(17)
Comprehensive income (loss) attributable to Vistra	$ 2,673	$ 1,492	$ (1,204)

VISTRA CORP.
CONSOLIDATED BALANCE SHEETS
(Millions of Dollars, Except Share Data)

	December 31, 2024	December 31, 2023
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,188	$ 3,485
Restricted cash	28	40
Trade accounts receivable — net	1,982	1,674
Income taxes receivable	8	6
Inventories	970	740
Commodity and other derivative contractual assets	2,587	3,645
Margin deposits related to commodity contracts	406	1,244
Margin deposits posted under affiliate financing agreement	435	439
Prepaid expense and other current assets	515	364
Total current assets	8,119	11,637
Restricted cash	6	14
Investments	4,512	2,035
Property, plant, and equipment — net	18,173	12,432
Goodwill	2,807	2,583
Identifiable intangible assets — net	2,213	1,864
Commodity and other derivative contractual assets	740	577
Accumulated deferred income taxes	9	1,223
Other noncurrent assets	1,191	601
Total assets	$ 37,770	$ 32,966
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts receivable financing	$ 750	$ —
Long-term debt due currently	880	2,286
Forward repurchase obligation due currently	703	—
Trade accounts payable	1,510	1,147
Commodity and other derivative contractual liabilities	3,351	5,258
Margin deposits related to commodity contracts	49	45
Accrued taxes other than income	209	203
Accrued interest	193	206
Asset retirement obligations	142	124
Other current liabilities	645	554
Total current liabilities	8,432	9,823
Margin deposits financing with affiliate	435	439
Long-term debt, less amounts due currently	15,418	12,116
Forward repurchase obligation, less amounts due currently	632	—
Commodity and other derivative contractual liabilities	1,367	1,688
Accumulated deferred income taxes	697	1
Tax Receivable Agreement obligation	14	164
Asset retirement obligations	3,936	2,414
Other noncurrent liabilities and deferred credits	1,256	999
Total liabilities	32,187	27,644
Commitments and Contingencies		

VISTRA CORP.
CONSOLIDATED BALANCE SHEETS
(Millions of Dollars, Except Share Data)

	December 31,	
	2024	**2023**
Total equity:		
Preferred stock (100,000,000 shares authorized, $1,000 liquidation preference per share, 2,476,066 and 2,476,081 shares outstanding at December 31, 2024 and 2023, respectively)	2,476	2,476
Common stock (par value $0.01 per share, 1,800,000,000 shares authorized, 339,754,307 and 351,457,016 shares outstanding at December 31, 2024 and 2023, respectively)	5	5
Treasury stock, at cost (208,998,299 and 192,178,156 shares at December 31, 2024 and 2023, respectively)	(5,912)	(4,662)
Additional paid-in-capital	9,435	10,095
Accumulated deficit	(454)	(2,613)
Accumulated other comprehensive income	20	6
Stockholders' equity	5,570	5,307
Noncontrolling interest in subsidiary	13	15
Total equity	5,583	5,322
Total liabilities and equity	$ 37,770	$ 32,966

VISTRA CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions of Dollars)

	Year Ended December 31,		
	2024	**2023**	**2022**
Cash flows — operating activities:			
Net income (loss)	$ 2,812	$ 1,492	$ (1,210)
Adjustments to reconcile net income (loss) to cash provided by (used in) operating activities:			
Depreciation and amortization	2,631	1,956	2,047
Deferred income tax expense (benefit), net	607	457	(359)
Gain on sale of land	—	(95)	(8)
Impairment of long-lived and other assets	—	49	74
Unrealized net (gain) loss from mark-to-market valuations of commodities	(1,155)	(490)	2,510
Unrealized net (gain) loss from mark-to-market valuations of interest rate swaps	(53)	36	(250)
Unrealized net gain from nuclear decommissioning trusts	(116)	—	—
Change in asset retirement obligation liability	38	27	13
Asset retirement obligation accretion expense	114	34	34
Impacts of Tax Receivable Agreement	5	164	128
Gain on TRA repurchase and tender offers	(10)	(29)	—
Bad debt expense	183	164	179
Stock-based compensation	100	77	63
Other, net	(89)	103	(71)
Changes in operating assets and liabilities:			
Accounts receivable — trade	(242)	214	(852)
Inventories	(31)	(174)	36
Accounts payable — trade	19	(350)	94
Commodity and other derivative contractual assets and liabilities	(175)	82	(228)
Margin deposits, net	842	1,899	(1,874)
Uplift securitization proceeds receivable from ERCOT	—	—	544
Accrued interest	(18)	46	16
Accrued taxes	(1)	5	(8)
Accrued employee incentive	8	58	21
Asset retirement obligation settlement	(88)	(81)	(87)
Major plant outage deferral	(91)	(32)	20
Other — net assets	(616)	84	(17)
Other — net liabilities	(111)	(243)	(330)
Cash provided by operating activities	4,563	5,453	485
Cash flows — investing activities:			
Capital expenditures, including nuclear fuel purchases and LTSA prepayments	(2,078)	(1,676)	(1,301)
Energy Harbor acquisition (net of cash acquired)	(3,065)	—	—
Proceeds from sales of nuclear decommissioning trust fund securities	2,216	601	670
Investments in nuclear decommissioning trust fund securities	(2,239)	(624)	(693)
Proceeds from sales of environmental allowances	773	500	1,275
Purchases of environmental allowances	(1,226)	(1,071)	(1,303)
Proceeds from sales of property, plant, and equipment, including nuclear fuel	196	115	78
Proceeds from sales of transferable ITCs	150	—	—

See Notes to the Consolidated Financial Statements

VISTRA CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions of Dollars)

	Year Ended December 31,		
	2024	2023	2022
Other, net	(3)	10	35
Cash used in investing activities	(5,276)	(2,145)	(1,239)
Cash flows — financing activities:			
Issuances of long-term debt	3,817	2,498	1,498
Repayments/repurchases of debt	(2,287)	(33)	(251)
Net borrowings (repayments) under accounts receivable financing	750	(425)	425
Borrowings under Revolving Credit Facility	50	100	1,750
Repayments under Revolving Credit Facility	(50)	(350)	(1,500)
Borrowings under Commodity-Linked Facility	1,802	—	3,150
Repayments under Commodity-Linked Facility	(1,802)	(400)	(2,750)
Debt issuance costs	(76)	(59)	(31)
Stock repurchases	(1,266)	(1,245)	(1,949)
Dividends paid to common stockholders	(305)	(313)	(302)
Dividends paid to preferred stockholders	(173)	(150)	(151)
Dividends paid to noncontrolling and redeemable noncontrolling interest holders	(180)	—	—
Payment for acquisition of noncontrolling interest	(1,748)	—	—
TRA Repurchase and tender offer — return of capital	(122)	—	—
Other, net	(14)	83	31
Cash used in financing activities	(1,604)	(294)	(80)
Net change in cash, cash equivalents and restricted cash	(2,317)	3,014	(834)
Cash, cash equivalents and restricted cash — beginning balance	3,539	525	1,359
Cash, cash equivalents and restricted cash — ending balance	$ 1,222	$ 3,539	$ 525

See Notes to the Consolidated Financial Statements

VISTRA CORP.
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Millions of Dollars)

	Preferred Stock	Common Stock	Treasury Stock	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Noncontrolling Interest in Subsidiary	Total Equity
Balances at December 31, 2021	$ 2,000	$ 5	$(1,558)	$ 9,824	$ (1,964)	$ (16)	$ 8,291	$ 1	$ 8,292
Stock repurchases	—	—	(1,837)	—	—	—	(1,837)	—	(1,837)
Effects of stock-based incentive compensation plans	—	—	—	103	—	—	103	—	103
Net income (loss)	—	—	—	—	(1,227)	—	(1,227)	17	(1,210)
Dividends declared on common stock	—	—	—	—	(302)	—	(302)	—	(302)
Dividends declared on preferred stock	—	—	—	—	(151)	—	(151)	—	(151)
Change in accumulated other comprehensive income (loss)	—	—	—	—	—	23	23	—	23
Other	—	—	—	1	1	—	2	(2)	—
Balances at December 31, 2022	$ 2,000	$ 5	$(3,395)	$ 9,928	$ (3,643)	$ 7	$ 4,902	$ 16	$ 4,918
Series C Preferred Stock issued	476	—	—	—	—	—	476	—	476
Stock repurchases	—	—	(1,267)	—	—	—	(1,267)	—	(1,267)
Effects of stock-based incentive compensation plans	—	—	—	168	—	—	168	—	168
Net income (loss)	—	—	—	—	1,493	—	1,493	(1)	1,492
Dividends declared on common stock	—	—	—	—	(313)	—	(313)	—	(313)
Dividends declared on preferred stock	—	—	—	—	(150)	—	(150)	—	(150)
Change in accumulated other comprehensive income (loss)	—	—	—	—	—	(1)	(1)	—	(1)
Other	—	—	—	(1)	—	—	(1)	—	(1)
Balances at December 31, 2023	$ 2,476	$ 5	$(4,662)	$10,095	$ (2,613)	$ 6	$ 5,307	$ 15	$ 5,322
Stock repurchases			(1,250)				(1,250)		(1,250)
Effects of stock-based incentive compensation plans	—	—	—	140	—	—	140	—	140
Net income	—	—	—	—	2,659	—	2,659	102	2,761
Dividends declared on common stock	—	—	—	—	(307)	—	(307)	—	(307)
Dividends declared on preferred stock	—	—	—	—	(192)	—	(192)	—	(192)
Dividends to noncontrolling interest	—	—	—	—	—	—	—	(15)	(15)
Change in accumulated other comprehensive income (loss)	—	—	—	—	—	14	14	—	14
Equity issued in subsidiary to acquire Energy Harbor	—	—	—	747	—	—	747	1,560	2,307

See Notes to the Consolidated Financial Statements

VISTRA CORP.
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Millions of Dollars)

	Preferred Stock	Common Stock	Treasury Stock	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Noncontrolling Interest in Subsidiary	Total Equity
Modification of noncontrolling interest to redeemable noncontrolling interest (a)	—	—	—	(1,539)	—	—	(1,539)	(1,659)	(3,198)
Other	—	—	—	(8)	(1)	—	(9)	10	1
Balances at December 31, 2024	$ 2,476	$ 5	$ (5,912)	$ 9,435	$ (454)	$ 20	$ 5,570	$ 13	$ 5,583

(a) See Note 2 for additional information regarding activity associated with noncontrolling interest.

1. BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Description of Business

References in this report to "we," "our," "us" and "the Company" are to Vistra and/or its subsidiaries, as apparent in the context. See *Glossary of Terms and Abbreviations* for defined terms.

Vistra is a holding company operating an integrated retail and electric power generation business primarily in markets throughout the U.S. Through our subsidiaries, we are engaged in competitive energy market activities including electricity generation, wholesale energy sales and purchases, commodity risk management, and retail sales of electricity and natural gas to end users.

Vistra has five reportable segments: (i) Retail, (ii) Texas, (iii) East, (iv) West, and (v) Asset Closure. See Note 19 for additional information.

Significant Accounting Policies

Basis of Presentation

The consolidated financial statements have been prepared in accordance with U.S. GAAP and on the same basis as the audited financial statements included in our 2023 Form 10-K. All intercompany items and transactions have been eliminated in consolidation. All dollar amounts in the financial statements and tables in the notes are stated in millions of U.S. dollars unless otherwise indicated. Certain prior period amounts have been reclassified to conform with the current year presentation.

Use of Estimates

Preparation of financial statements requires estimates and assumptions about future events that affect the reporting of assets and liabilities as of the balance sheet dates and the reported amounts of revenue and expense, including fair value measurements, estimates of expected obligations, judgments related to the potential timing of events, and other estimates. In the event estimates and/or assumptions prove to be different from actual amounts, adjustments are made in subsequent periods to reflect more current information.

Business Combinations

The Company accounts for its business combinations in accordance with ASC 805, *Business Combinations*, which requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value as of the acquisition date. The excess of the purchase price over those fair values is recognized as goodwill (if any). During the measurement period, which may be up to one year from the acquisition date, we may record adjustments to the assets acquired and liabilities assumed in the period in which they are determined. See Note 2 for additional information.

Derivative Instruments and Mark-to-Market Accounting

We enter derivative instruments, including commodity contracts and interest rate swaps, to manage commodity price and interest rate risks. All our derivatives are accounted for as economic hedges and are recorded at estimated fair value in the consolidated balance sheets with changes in fair value recorded as gains or losses in the earnings of the period in which they occur. No derivative positions are accounted for as cash flow or fair value hedges. When derivative instruments are settled and realized gains and losses are recorded, the previously recorded unrealized gains and losses and derivative assets and liabilities are reversed.

A commodity-related derivative contract may be designated as a normal purchase or sale if the commodity is to be physically received or delivered for use or sale in the normal course of business. If designated as normal, the derivative contract is accounted for under the accrual method of accounting (not marked-to-market) with no balance sheet or income statement recognition of the contract until settlement.

We report derivative instruments in the consolidated balance sheets as commodity and other derivative contractual assets or liabilities on a gross basis without taking into consideration netting arrangements we have with counterparties. We maintain standardized master netting agreements with certain counterparties that allow for the right to offset derivative assets and liabilities, receivables and payables on settled positions, and collateral to reduce credit exposure between us and the counterparty.

Generally, margin deposits that contractually offset derivative instruments are reported separately in the consolidated balance sheets, except for certain margin amounts related to changes in fair value on CME transactions that are legally characterized as settlement of forward exposure rather than collateral.

We report commodity hedging and trading results as revenue, fuel expense, or purchased power in the consolidated statements of operations depending on the type of activity. Electricity hedges, financial natural gas hedges, and trading activities are primarily reported as revenue. Physical hedges for coal or fuel oil, along with physical natural gas trades, are primarily reported as fuel expense. Realized and unrealized gains and losses associated with interest rate swap transactions are reported in the consolidated statements of operations in interest expense. See Note 11 for additional information.

Revenue Recognition

Revenue is recognized when electricity is delivered to our customers in an amount that we expect to invoice for volumes delivered or services provided. Sales tax is excluded from revenue. Energy sales and services that have been delivered but not billed by period end are estimated. Accrued unbilled revenues are based on estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Estimated amounts are adjusted when actual usage is known and billed.

We record wholesale generation revenue when volumes are delivered or services are performed for transactions that are not accounted for on a mark-to-market basis. These revenues primarily consist of physical electricity sales to the ISO/RTO, ancillary service revenue for reliability services, capacity revenue for making installed generation and demand response available for system reliability requirements, and certain other electricity sales contracts. See Note 3 for additional information. See *Derivative Instruments and Mark-to-Market Accounting* for revenue recognition related to derivative contracts.

Government Assistance

The Company qualifies for tax incentives through eligible construction spending and production through the Inflation Reduction Act of 2022 (IRA). These tax incentives generally provide for transferable tax credits upon the applicable qualifying event for the credit type, typically production or in-service date. We account for transferable ITCs and PTCs we expect to receive by analogy to the grant model within International Accounting Standards 20, *Accounting for Government Grants and Disclosures of Government Assistance* (IAS 20). Transferable PTCs are included in other noncurrent assets in the consolidated balance sheet and included in revenues in the consolidated statements of operations when receipt of the credit is reasonably assured. Transferable investment tax credits (ITCs) are included in other noncurrent assets on the consolidated balance sheet with a corresponding reduction to the cost basis of the Company's plant assets when receipt of the credit is reasonably assured, and reduces depreciation expense over the life of the asset. We believe the reasonable assurance term as used in IAS 20 is analogous to the term probable as defined in ASC 450-20 of U.S. GAAP. See Note 4 for additional information.

Major Maintenance Costs

Major maintenance costs incurred during generation plant outages are deferred and amortized into operating costs over the period between the major maintenance outages for the respective asset. Other routine costs of maintenance activities are charged to expense as incurred and reported as operating costs in the consolidated statements of operations.

Defined Benefit Pension Plans and OPEB Plans

Certain health care and life insurance benefits are offered to eligible employees and their dependents upon the retirement of such employees from the company. Pension benefits are offered to eligible employees under collective bargaining agreements based on either a traditional defined benefit formula or a cash balance formula. Costs of pension and OPEB plans are dependent upon numerous factors, assumptions and estimates. See Note 14 for additional information.

Stock-Based Compensation

Stock-based compensation is accounted for in accordance with ASC 718, *Compensation - Stock Compensation.* We recognize compensation expense for graded vesting awards on a straight-line basis over the requisite service period for the entire award. Forfeitures are recognized as they occur. See Note 18 for additional information.

Sales and Excise Taxes

Sales and excise taxes are accounted for as "pass through" items in the consolidated balance sheets with no effect on the consolidated statements of operations (*i.e.*, the tax is billed to customers and recorded as trade accounts receivable with an offsetting amount recorded as a liability to the taxing jurisdiction in other current liabilities in the consolidated statements of operations).

Franchise and Revenue-Based Taxes

Unlike sales and excise taxes, franchise and revenue-based taxes are not "pass through" items. These taxes are imposed on us by state and local taxing authorities, based on revenues or kWh delivered, as a cost of doing business and are recorded as an expense. Rates we charge to customers are intended to recover our costs, including the franchise and revenue-based receipt taxes, but we are not acting as an agent to collect the taxes from customers. We report franchise and revenue-based taxes in SG&A expense in the consolidated statements of operations.

Income Taxes

Deferred income tax assets and liabilities are recorded to reflect, among other things, the temporary timing differences between the book basis and tax basis of assets and liabilities, as required under accounting rules. Investment tax credits that are not transferable are accounted for using the deferral method, which reduces the tax basis of our solar and battery storage facilities. As of both December 31, 2024 and 2023, deferred tax assets related to these credits totaled $69 million. We report interest and penalties related to uncertain tax positions as current income tax expense. See Note 5 for additional information.

Accounting for Contingencies

Our financial results may be affected by judgments and estimates related to loss contingencies. Accruals for loss contingencies are recorded when management determines that it is probable that a liability has been incurred and that such economic loss can be reasonably estimated. Such determinations are subject to interpretations of current facts and circumstances, forecasts of future events and estimates of the financial impacts of such events. See Note 15 for additional information.

Cash and Cash Equivalents

For purposes of reporting cash and cash equivalents, temporary cash investments purchased with an original maturity of three months or less are considered cash equivalents.

Property, Plant, and Equipment

Property, plant, and equipment has been recorded at estimated fair values at the time of acquisition for assets acquired or at cost for capital improvements and individual facilities developed. Significant improvements or additions to our property, plant, and equipment that extend the life of the respective asset are capitalized at cost, while other costs are expensed when incurred. The cost of self-constructed property additions includes materials and both direct and indirect labor, including payroll-related costs. Interest related to qualifying construction projects and qualifying software projects is capitalized in accordance with accounting guidance related to capitalization of interest cost.

Depreciation of our property, plant, and equipment (except for nuclear fuel) is calculated on a straight-line basis over the estimated service lives of the properties. Depreciation expense is calculated on an asset-by-asset basis. Estimated depreciable lives are based on management's estimates of the assets' economic useful lives. See Note 6 for additional information.

Nuclear Fuel

Nuclear fuel is capitalized and reported as a component of our property, plant, and equipment in the consolidated balance sheets. Amortization of nuclear fuel is calculated on the units-of-production method and is reported as a component of fuel, purchased power costs, and delivery fees in the consolidated statements of operations.

Impairment of Long-Lived Assets

We evaluate long-lived assets (including intangible assets with finite lives) for impairment whenever indications of impairment exist. The carrying value of such assets is deemed to be impaired if the projected undiscounted cash flows are less than the carrying value. If there is such impairment, a loss is recognized based on the amount by which the carrying value exceeds the fair value. Fair value is determined primarily by discounted cash flows, supported by available market valuations, if applicable. See Note 6 for additional information.

Goodwill and Intangible Assets with Indefinite Lives

As part of our fresh start reporting and purchase accounting from acquisitions, reorganization value or the purchase consideration is generally allocated, first, to identifiable tangible assets and liabilities, identifiable intangible assets and liabilities, then any remaining excess reorganization value or purchase consideration is allocated to goodwill. We evaluate goodwill and intangible assets with indefinite lives for impairment at least annually, or when indications of impairment exist. We have established October 1 as the date we evaluate goodwill and intangible assets with indefinite lives for impairment. See Note 7 for additional information.

Asset Retirement Obligations (ARO)

A liability is initially recorded at fair value for an asset retirement obligation associated with the legal obligation associated with law, regulatory, contractual or constructive retirement requirements of tangible long-lived assets in the period in which it is incurred if a fair value is reasonably estimable. At initial recognition of an ARO obligation, an offsetting asset is also recorded for the long-lived asset that the liability corresponds with, which is subsequently depreciated over the estimated useful life of the asset. These liabilities primarily relate to our nuclear generation plant decommissioning, land reclamation related to lignite mining and removal of lignite/coal-fueled plant ash treatment facilities. Over time, the liability is accreted for the change in present value and the initial capitalized costs are depreciated over the remaining useful lives of the assets. Generally, changes in estimates related to ARO obligations are recorded as increases or decreases to the liability and related asset as information becomes available. Changes in estimates related to assets that have been retired or for which costs are not recoverable are recorded as operating costs in the consolidated statements of operations. See Note 13 for additional information.

Inventories

Inventories consist of materials and supplies, fuel stock and natural gas in storage. Materials and supplies inventory is valued at weighted average cost and is expensed or capitalized when used for repairs/maintenance or capital projects, respectively. Fuel stock and natural gas in storage are reported at the lower of cost (calculated on a weighted average basis) or net realizable value. We expect to recover the value of inventory costs in the normal course of business. See Note 20 for additional information.

Nuclear Decommissioning Trust (NDT) Investments and Regulatory Assets or Liability

The NRC is responsible for regulating all nuclear power plants in the U.S. This regulatory oversight results in specific accounting considerations for nuclear plant decommissioning. Our NDTs hold funds primarily for the ultimate decommissioning of our nuclear power plants. Each unit has its own NDT and funds from one unit may not be used to fund decommissioning obligations of another unit.

Decommissioning costs associated with the Comanche Peak nuclear generation facility in Texas are being recovered from Oncor Electric Delivery Company LLC's (Oncor) customers as a delivery fee surcharge over the life of the plant and deposited by Vistra (and prior to the Effective Date, a subsidiary of TCEH) in the NDT. As a result, the asset retirement obligation and the investments in the decommissioning trust are accounted for as rate regulated operations. Changes in these accounts, including investment income and accretion expense, do not impact net income, but are reported as a change in the corresponding regulatory asset or liability balance that is reflected in the consolidated balance sheets as other noncurrent assets or other noncurrent liabilities and deferred credits.

The NDTs associated with our PJM nuclear facilities have been funded with amounts collected from the previous owners and their respective utility customers. Any shortfall of funds necessary for decommissioning the PJM nuclear facilities, determined for each generating station unit, are required to be funded by us. Investments in the PJM NDTs are carried at fair value and gains and losses are recognized as other income or other deductions in the consolidated statements of operations. NDTs are invested in diversified portfolios of securities generally designed to achieve a return sufficient to fund the future decommissioning work. We retain any funds remaining in the trusts of the PJM nuclear facilities after all decommissioning has been completed.

Noncontrolling Interest and Redeemable Noncontrolling Interest in Subsidiary

A noncontrolling interest in a consolidated subsidiary represents the portion of the equity in a subsidiary not attributable, directly or indirectly, to the Company. Noncontrolling interests are presented as a separate component of equity in the consolidated balance sheets and the presentation of net income is modified to present earnings attributed to controlling and noncontrolling interests. Any change in ownership of a subsidiary while the controlling financial interest is retained is accounted for as an equity transaction between the controlling and noncontrolling interests. See Note 2 for additional information.

Redeemable noncontrolling interests are presented as a component of temporary equity in the mezzanine section of the consolidated balance sheet and the presentation of net income is modified to present earnings attributed to the controlling and redeemable noncontrolling interest. In December 2024, we closed on the repurchase of the noncontrolling interest in Vistra Vision and reclassified the remaining future payments attributable to the redeemable noncontrolling interest to a financing obligation. See Note 2 and Note 9 for additional information.

Treasury Stock

Treasury stock purchases are accounted for under the cost method whereby the entire cost of the acquired stock is recorded as treasury stock, which is presented in the consolidated balance sheets as a reduction to additional paid-in capital. Treasury stock purchases made by third party brokers on our behalf are recorded on a trade date basis when we are contractually obligated to pay the broker for their repurchase costs. See Note 16 for additional information.

Leases

At the inception of a contract we determine if it is or contains a lease, which involves the contract conveying the right to control the use of explicitly or implicitly identified property, plant, or equipment for a period of time in exchange for consideration.

Right-of-use (ROU) assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. ROU assets and lease liabilities are recognized at the commencement date of the underlying lease based on the present value of lease payments over the lease term. We use our secured incremental borrowing rate based on the information available at the lease commencement date to determine the present value of lease payments. Operating leases are included in other noncurrent assets, other current liabilities, and other noncurrrent liabilities and deferred credits on the consolidated balance sheet. Finance leases are included in property, plant, and equipment, other current liabilities and other noncurrent liabilities and deferred credits on the consolidated balance sheet. Lease term includes options to extend or terminate the lease when it is reasonably certain that we will exercise the option. We apply the practical expedient permitted by ASC *842, Leases* to not separate lease and non-lease components for a majority of our lease asset classes.

Leases with an initial lease term of 12 months or less are not recorded on the balance sheet; we recognize lease expense for these leases on a straight-line basis over the lease term.

Adoption of Accounting Standards in 2024

Improvements to Reportable Segment Disclosures

In November 2023, the Financial Accounting Standards Board (FASB) issued ASU No. 2023-07, *Segment Reporting (Topic 280), Improvements to Reportable Segment Disclosures*, to improve the disclosures about reportable segments and add more detailed information about a reportable segment's expenses. The amendments in the ASU require public entities to disclose on an annual and interim basis significant segment expenses that are regularly provided to the chief operating decision maker (CODM) and included within each reported measure of segment profit or loss, other segment items by reportable segment, the title and position of the CODM, and an explanation of how the CODM uses the reported measures of segment profit or loss in assessing segment performance and deciding how to allocate resources. The ASU does not change the definition of a segment, the method for determining segments, the criteria for aggregating operating segments into reportable segments, or the current specifically enumerated segment expenses that are required to be disclosed. The Company adopted the amendments in this ASU for its fiscal year ended December 31, 2024 which resulted in disclosure of significant segment expenses such as segment fuel, purchased power costs, and delivery fees, operating costs, and selling, general, and administrative expenses. The amendment was applied retrospectively to all prior periods presented. See Note 19 for additional information.

Recent Accounting Pronouncements

Improvements to Income Tax Disclosures

In December 2023, the FASB issued ASU No. 2023-09 (ASU 2023-09), *Income Taxes (Topic 740): Improvements to Income Tax Disclosures* to enhance the transparency and decision usefulness of income tax disclosures. ASU 2023-09 is effective for annual periods beginning after December 15, 2024 on a prospective basis. Early adoption is permitted. As the amendments apply to income tax disclosures only, the Company does not expect adoption to have a material impact on the consolidated financial statements.

Expense Disaggregation Disclosures

In November 2024, the FASB issued ASU No. 2024-03 (ASU 2024-03), *Income Statement – Reporting Comprehensive Income – Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses* to improve disclosures by providing additional information about certain expenses in the notes to financial statements in interim and annual reporting periods. Among other provisions, the new standard requires disclosure of disaggregated amounts for expenses such as employee compensation, depreciation, and intangible asset amortization included in each expense caption presented on the face of the income statement. ASU 2024-03 is effective for annual periods beginning after December 15, 2026 and interim periods within annual reporting periods beginning after December 15, 2027 and can be applied prospectively or retrospectively. Early adoption is permitted. We are currently evaluating the impact this ASU will have on the consolidated financial statements and related disclosures.

Recent Developments

In January, a fire occurred at our Moss Landing 300 MW battery energy storage facility in the West segment. We are still investigating the cause of the fire and impacts, including insurance claim recoveries, but expect to write off approximately $400 million of plant value to depreciation expense in the first quarter of 2025, representing the remaining net book value of the facility. Moss Landing 300 is part of the Moss Landing complex, which includes two other battery facilities and a gas plant, with an aggregate book value of approximately $1 billion. While the gas plant is operational, the other two battery facilities remain offline as we investigate the fire. We will continue to assess if a triggering event has occurred to evaluate impairment for the other complex assets.

2. ACQUISITIONS

Energy Harbor Business Combination

On March 1, 2024 (Merger Date), pursuant to a transaction agreement dated March 6, 2023 (Transaction Agreement), (i) Vistra Operations transferred certain of its subsidiary entities into Vistra Vision, (ii) Black Pen Inc., a wholly owned subsidiary of Vistra, merged with and into Energy Harbor, (iii) Energy Harbor became a wholly owned subsidiary of Vistra Vision, and (iv) affiliates of Nuveen Asset Management, LLC (Nuveen) and Avenue Capital Management II, L.P. (Avenue) exchanged a portion of the Energy Harbor shares held by Nuveen and Avenue for a 15% equity interest of Vistra Vision (collectively, Energy Harbor Merger). The Energy Harbor Merger combined Energy Harbor's and Vistra's nuclear and retail businesses and certain Vistra Zero renewables and energy storage facilities to provide diversification and scale across multiple carbon-free technologies (dispatchable and renewables/storage) and the retail business.

The Energy Harbor Merger was accounted for using the acquisition method in accordance with ASC 805, *Business Combinations* (ASC 805), which requires identifiable assets acquired and liabilities assumed to be recorded at their estimated fair values on the Merger Date. The combined results of operations are reported in the consolidated financial statements beginning as of the Merger Date.

The following table summarizes the acquisition date fair value of Energy Harbor associated with the Energy Harbor Merger on the Merger Date:

	Consideration (in millions)
Cash consideration	$ 3,100
15% of the fair value of net assets contributed to Vistra Vision by Vistra (a)	1,496
Total purchase price	4,596
Fair value of noncontrolling interest in Energy Harbor (b)	811
Acquisition date fair value of Energy Harbor	$ 5,407

(a) Valued using a discounted cash flow analysis of the contributed subsidiaries including contributed debt.
(b) Represents 15% of the acquisition date fair value implied from the fair value of consideration transferred.

As a result of the Energy Harbor Merger, Vistra maintained an 85% ownership interest in Vistra Vision and recorded the remaining 15% equity interest as a noncontrolling interest in the consolidated balance sheets as of the Merger Date. On the Merger Date, we reclassified the carrying value of assets contributed to Vistra Vision of $749 million from additional paid-in-capital of Vistra (the controlling interest) to the noncontrolling interest in subsidiary.

Provisional fair value measurements were made for acquired assets and liabilities in the first quarter of 2024 and adjustments to those measurements were made in the second, third and fourth quarters of 2024. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of the acquisition to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date. The provisional fair values assigned to assets acquired and liabilities assumed are as follows:

	Fair Value as of March 1, 2024	Measurement Period Adjustments recorded through December 31, 2024
	(in millions)	
Cash and cash equivalents	$ 35	$ 5
Trade accounts receivables, inventories, prepaid expenses, and other current assets	544	6
Investments (a)	2,021	—
Property, plant, and equipment (b)	5,616	(4)
Identifiable intangible assets (c)	444	16
Commodity and other derivative contractual assets (d)	129	(11)
Other noncurrent assets	61	53
Total identifiable assets acquired	8,850	65
Trade accounts payable and other current liabilities	320	57
Long-term debt, including amounts due currently	413	—
Commodity and other derivative contractual liabilities (d)	179	—
Accumulated deferred income taxes	1,314	(50)
Asset retirement obligations (e)	1,368	—
Identifiable intangible liabilities	55	(18)
Other noncurrent liabilities and deferred credits	18	6
Total identifiable liabilities assumed	3,667	(5)
Identifiable net assets acquired	5,183	70
Goodwill (f)	224	(70)
Net assets acquired	$ 5,407	

(a) Investments represent securities held in nuclear decommissioning trusts (NDT) for the purpose of funding the future retirement and decommissioning of the PJM nuclear generation facilities. These investments include equity, debt and other fixed-income securities consistent with investment rules established by the NRC. They are valued using a market approach (Level 1 or Level 2 depending on security).
(b) Acquired property, plant, and equipment are valued using a combination of an income approach and a market approach. The income approach utilized a discounted cash flow analysis based upon a debt-free, free cash flow model (Level 3).
(c) Includes acquired nuclear fuel supply contracts valued based on contractual cash flow projections over approximately five years compared with cash flows based on current market prices with the resulting difference discounted to present value (Level 3). Also includes acquired retail customer relationships which are valued based on discounted cash flow analysis of acquired customers and estimated attrition rates (Level 3).
(d) Acquired derivatives are valued using the methods described in Note 11 (Level 1, Level 2, or Level 3). Contracts with terms that were not at current market prices are also valued using a discounted cash flow analysis (Level 3).
(e) Asset retirement obligations are valued using a discounted cash flow model which, on a unit-by-unit basis, considers multiple decommissioning methods and are based on decommissioning cost studies (Level 3).
(f) The excess of the consideration transferred over the fair value of identifiable assets acquired and liabilities assumed is recorded as goodwill. Goodwill represents expected synergies to be generated from combining operations of Energy Harbor with Vistra. None of the Goodwill is deductible for income tax purposes.

The following unaudited pro forma financial information for the years ended December 31, 2024 and 2023 assumes that the Energy Harbor Merger occurred on January 1, 2023. The unaudited pro forma financial information is provided for informational purposes only and is not necessarily indicative of the results of operations that would have occurred had the Energy Harbor Merger been completed on January 1, 2023, nor is the unaudited pro forma financial information indicative of future results of operations, which may differ materially from the pro forma financial information presented here.

	Year Ended December 31,	
	2024	2023
	(in millions)	
Revenues	$ 17,948	$ 17,148
Net income	$ 2,901	$ 1,398

The unaudited pro forma financial information presented above includes adjustments for incremental depreciation and amortization as a result of the fair value determination of the net assets acquired, interest expense on debt assumed in the Energy Harbor Merger, effects of the Energy Harbor Merger on tax expense (benefit), and other related adjustments. Determining the amounts of revenue and earnings of Energy Harbor since the acquisition date is impractical as operations have been integrated into our commercial platform which is managed at a portfolio level.

Acquisition costs incurred in the Energy Harbor Merger totaled $25 million and $24 million for the year ended December 31, 2024 and 2023, respectively, and are classified as selling, general, and administrative expenses in the consolidated statements of operations.

Acquisition of Noncontrolling Interest

On September 18, 2024, Vistra Operations and Vistra Vision Holdings I LLC, an indirect wholly owned subsidiary of Vistra Operations (Vistra Vision Holdings), entered into separate Unit Purchase Agreements (the UPAs) with each of Nuveen and Avenue, pursuant to which Vistra Vision Holdings agreed to purchase each of Nuveen's and Avenue's combined 15% noncontrolling interest in Vistra Vision for approximately $3.2 billion in cash. The UPAs contained certain closing conditions outside our control that represent conditional redemption obligations that required us to reflect the transaction as redeemable noncontrolling interest within the mezzanine section of the consolidated balance sheet as of September 30, 2024. The UPAs were amended prior to close to accelerate principal payments to Avenue and certain Nuveen noncontrolling interest holders. The transaction closed on December 31, 2024 (Closing Date), with all closing conditions met. Upon closing, we reclassified the remaining future payments attributable to the redeemable noncontrolling interest to a financing obligation. See Note 9 for additional information.

3. REVENUE

Revenue Disaggregation

The following tables disaggregate our revenue by major source:

	Year Ended December 31, 2024						
	Retail	Texas	East (a)	West	Asset Closure	Eliminations / Corporate and Other	Consolidated
	(in millions)						
Revenue from contracts with customers:							
Retail energy charge in ERCOT	$ 8,064	$ —	$ —	$ —	$ —	$ —	$ 8,064
Retail energy charge in Northeast/Midwest (a)	3,595	—	—	—	—	—	3,595
Wholesale generation revenue from ISO/RTO	—	399	1,351	228	—	—	1,978
Capacity revenue from ISO/RTO (b)	—	—	74	—	—	—	74
Revenue from other wholesale contracts	—	422	398	230	—	—	1,050
Total revenue from contracts with customers	11,659	821	1,823	458	—	—	14,761
Other revenues:							
Transferable PTC revenues (c)	—	292	264	—	—	—	556
Hedging revenues — realized	1,241	(453)	31	84	(8)	—	895
Hedging revenue — unrealized	(168)	700	143	329	9	—	1,013
Intangible amortization and other revenues	1	—	(4)	—	—	2	(1)
Intersegment sales (d)	64	4,034	3,404	6	—	(7,508)	—
Total other revenues	1,138	4,573	3,838	419	1	(7,506)	2,463
Total revenues	$12,797	$ 5,394	$ 5,661	$ 877	$ 1	$ (7,506)	$ 17,224

(a) Includes ten months of revenue associated with operations acquired in the Energy Harbor Merger.

(b) Represents net capacity sold (purchased) in each ISO/RTO. The East segment includes $126 million of capacity sold offset by $52 million of capacity purchased. Net capacity purchased in each ISO/RTO included in fuel, purchased power costs, and delivery fees in the consolidated statement of operations includes capacity purchased of $139 million offset by $116 million of capacity sold within the East segment.

(c) Represents transferable PTCs generated from qualifying nuclear and solar assets during the period.

(d) East segment includes $195 million of intersegment unrealized net losses, and Texas and West segments include $74 million and $4 million, respectively, of intersegment unrealized net gains from mark-to-market valuations of commodity positions with the Retail segment.

	Year Ended December 31, 2023						
	Retail	Texas	East	West	Asset Closure	Eliminations / Corporate and Other	Consolidated
	(in millions)						
Revenue from contracts with customers:							
Retail energy charge in ERCOT	$ 7,674	$ —	$ —	$ —	$ —	$ —	$ 7,674
Retail energy charge in Northeast/Midwest	1,642	—	—	—	—	—	1,642
Wholesale generation revenue from ISO/RTO	—	1,190	1,298	421	—	—	2,909
Capacity revenue from ISO/RTO (a)	—	—	98	—	—	—	98
Revenue from other wholesale contracts	—	505	797	179	—	—	1,481
Total revenue from contracts with customers	9,316	1,695	2,193	600	—	—	13,804
Other revenues:							
Transferable PTC revenues (b)	—	10	—	—	—	—	10
Hedging revenues — realized	1,063	(885)	43	67	(36)	—	252
Hedging revenue — unrealized	191	(714)	958	243	36	—	714
Intangible amortization and other revenues	2	—	(5)	—	—	2	(1)
Intersegment sales (c)	—	3,873	2,701	4	—	(6,578)	—
Total other revenues	1,256	2,284	3,697	314	—	(6,576)	975
Total revenues	$10,572	$ 3,979	$ 5,890	$ 914	$ —	$ (6,576)	$ 14,779

(a) Represents net capacity sold (purchased) in each ISO/RTO. The East segment includes $233 million of capacity sold offset by $135 million of capacity purchased. Net capacity purchased in each ISO/RTO included in fuel, purchased power costs, and delivery fees in the consolidated statement of operations includes capacity purchased of $82 million offset by $73 million of capacity sold within the East segment.

(b) Represents transferable PTCs generated from qualifying solar assets during the period.

(c) East segment includes $814 million of intersegment unrealized net gains, and Texas and West segments include $48 million and $6 million, respectively, of intersegment unrealized net losses from mark-to-market valuations of commodity positions with the Retail segment.

	Year Ended December 31, 2022						
	Retail	Texas	East	West	Asset Closure	Eliminations / Corporate and Other	Consolidated
	(in millions)						
Revenue from contracts with customers:							
Retail energy charge in ERCOT	$ 6,971	$ —	$ —	$ —	$ —	$ —	$ 6,971
Retail energy charge in Northeast/Midwest	2,139	—	—	—	—	—	2,139
Wholesale generation revenue from ISO/RTO	—	1,277	1,987	467	562	—	4,293
Capacity revenue from ISO/RTO (a)	—	—	76	—	27	—	103
Revenue from other wholesale contracts	—	696	1,256	151	22	—	2,125
Total revenue from contracts with customers	9,110	1,973	3,319	618	611	—	15,631
Other revenues:							
Hedging revenues — realized	875	(67)	(247)	35	(333)	1	264
Hedging revenue — unrealized	(532)	(637)	(770)	(326)	102	—	(2,163)
Intangible amortization and other revenues	2	—	(6)	—	—	—	(4)
Intersegment sales (b)	—	2,609	2,133	9	4	(4,755)	—
Total other revenues	345	1,905	1,110	(282)	(227)	(4,754)	(1,903)
Total revenues	$ 9,455	$ 3,878	$ 4,429	$ 336	$ 384	$ (4,754)	$ 13,728

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(a) Represents net capacity sold (purchased) in each ISO/RTO. The East segment includes $361 million of capacity sold offset by $285 million of capacity purchased. The Asset Closure segment includes $27 million of capacity sold. Net capacity purchased in each ISO/RTO included in fuel, purchased power costs, and delivery fees in the consolidated statement of operations includes capacity purchased of $212 million offset by $167 million of capacity sold within the East segment.

(b) Texas and East segments include $780 million and $45 million, respectively, of intersegment unrealized net losses and West and Asset Closure segments include $2 million and $4 million respectively, of intersegment unrealized net gains from mark-to-market valuations of commodity positions with the Retail segment.

Retail Energy Charges

Revenue is recognized when electricity is delivered to our customers in an amount that we expect to invoice for volumes delivered or services provided. Sales tax is excluded from revenue. Payment terms vary from 15 to 60 days from invoice date. Revenue is recognized over-time using the output method based on kilowatt hours delivered. Energy charges are delivered as a series of distinct services and are accounted for as a single performance obligation.

Energy sales and services that have been delivered but not billed by period end are estimated. Accrued unbilled revenues are based on estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Estimated amounts are adjusted when actual usage is known and billed.

As contracts for retail electricity can be for multi-year periods, the Company has performance obligations under these contracts that have not yet been satisfied. These performance obligations have transaction prices that are both fixed and variable, and that vary based on the contract duration and customer type. For the fixed price contracts, the amount of any unsatisfied performance obligations will vary based on customer usage, which will depend on factors such as weather and customer activity and therefore it is not practicable to estimate such amounts.

Wholesale Generation Revenue from ISOs/RTOs and Revenue from Other Wholesale Contracts

Wholesale generation revenue is recognized when volumes are delivered to the ISO/RTO. Other wholesale contracts include other revenue activity with the ISO/RTO, such as ancillary services, auction revenue, neutrality revenue and revenue from nonaffiliated retail electric providers, municipalities or other wholesale counterparties. Wholesale revenues are recognized over time using the output method based on kilowatt hours delivered or other applicable performance measurements and cash is settled shortly after invoicing. Vistra operates as a market participant within ERCOT, PJM, ISO-NE, NYISO, MISO and CAISO and expects to continue to remain under contract with each ISO/RTO indefinitely. Wholesale revenues are delivered as a series of distinct services and are accounted for as a single performance obligation. When electricity is sold to and purchased from the same ISO/RTO in the same period, the excess of the amount sold over the amount purchased is reflected in wholesale generation revenues.

Capacity Revenue From ISO/RTO

We offer generation capacity into competitive ISO/RTO auctions in exchange for revenue from awarded capacity offers. Capacity ensures installed generation and demand response is available to satisfy system integrity and reliability requirements. Capacity revenues are recognized when the performance obligation is satisfied ratably over time as our power generation facilities stand ready to deliver power to the customer. Penalties are assessed by the ISO/RTO against generation facilities if the facility is not available during the capacity period and are recorded as a reduction to revenue. When capacity is sold to and purchased from the same ISO/RTO in the same period, the excess of the amount sold over the amount purchased is reflected in capacity revenue from ISO/RTO.

Other Revenues

Other revenues, as included in the tables of disaggregated revenue above, represent amounts not accounted for under ASC 606, *Revenue from Contracts with Customers* and are comprised of the following:

- Transferable production tax credit revenues accounted for as income-related grants by analogy to IAS 20 (see Note 4 for additional information).
- Intangible amortization of acquired intangible liabilities related to retail and wholesale contracts (see Note 7 for additional information).
- Hedging revenue from electricity and natural gas derivative contracts accounted for under ASC 815, *Derivatives and Hedging,* including the impact of realized and unrealized gains or losses on those contracts (see Note 11 for additional information).
- Intersegment sales are presented by segment and eliminated in consolidation.

Contract and Other Customer Acquisition Costs

We defer costs to acquire retail contracts and amortize these costs over the expected life of the contract. The expected life of a retail contract is calculated using historical attrition rates, which we believe to be an accurate indicator of future attrition rates. The deferred acquisition and contract cost balance as of December 31, 2024 and 2023 was $114 million and $97 million, respectively. The amortization related to these costs during the years ended December 31, 2024, 2023, and 2022 totaled $97 million, $88 million, and $83 million respectively, recorded as SG&A expenses, and $6 million, $6 million, and $6 million, respectively, recorded as a reduction to operating revenues in the consolidated statements of operations.

Practical Expedients

The majority of our revenues are recognized under the right to invoice practical expedient, which allows us to recognize revenue in the same amount that we have a right to invoice our customers. Unbilled revenues are recorded based on the volumes delivered and services provided to the customers at the end of the period, using the right to invoice practical expedient. We have elected to not disclose the value of unsatisfied performance obligations for contracts with variable consideration for which we recognize revenue using the right to invoice practical expedient. We use the portfolio approach in evaluating similar customer contracts with similar performance obligations. Sales taxes are not included in revenue.

Performance Obligations

As of December 31, 2024, we have future fixed fee performance obligations that are unsatisfied, or partially unsatisfied, relating to capacity auction volumes awarded through capacity auctions held by the ISO/RTO or contracts with customers for which the total consideration is fixed and determinable at contract execution. Capacity revenues are recognized as the performance obligations to make capacity available to the related ISOs/RTOs or counterparties are met.

	2025	2026	2027	2028	2029	2030 and Thereafter	Total
				(in millions)			
Remaining performance obligations	$ 1,123	$ 825	$ 289	$ 122	$ 62	$ 548	$ 2,969

Trade Accounts Receivable

	December 31, 2024	December 31, 2023
	(in millions)	
Wholesale and retail trade accounts receivable	$ 2,061	$ 1,735
Allowance for credit losses	(79)	(61)
Trade accounts receivable — net	$ 1,982	$ 1,674
Trade accounts receivable from contracts with customers — net	$ 1,514	$ 1,239
Other trade accounts receivable — net	468	435
Total trade accounts receivable — net	$ 1,982	$ 1,674

Gross trade accounts receivable as of December 31, 2024 and December 31, 2023 include unbilled retail revenues of $802 million and $614 million, respectively.

Allowance for Credit Losses on Accounts Receivable

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Allowance for credit losses on accounts receivable at beginning of period	$ 61	$ 65	$ 45
Increase for bad debt expense	183	164	179
Decrease for account write-offs	(165)	(168)	(159)
Allowance for credit losses on accounts receivable at end of period	$ 79	$ 61	$ 65

4. GOVERNMENT ASSISTANCE

Inflation Reduction Act of 2022 (IRA)

In August 2022, the U.S. enacted the IRA, which, among other things, implements substantial new and modified energy tax credits, including recognizing the value of existing carbon-free nuclear power by providing for a nuclear PTC, a solar PTC, and a first-time stand-alone battery storage investment tax credit. The section 45U nuclear PTC provides a federal tax credit of up to $15 per MWh, subject to phase out as power prices increase above $25 per MWh, to existing nuclear facilities from 2024 through 2032 subject to an annual inflation adjustment. The Company accounts for transferable ITCs and PTCs we expect to receive by analogy to the grant model within International Accounting Standards 20, *Accounting for Government Grants and Disclosures of Government Assistance*.

Transferable PTCs

In the year ended December 31, 2024, we recognized transferable nuclear PTC revenues of $545 million and transferable solar PTC revenues of $11 million. Our nuclear PTC revenues are an estimate based on gross receipts generated from qualifying nuclear production in 2024 and reflect our determination that we will meet the prevailing wage requirements necessary to earn the five times multiplier at all of our nuclear units. Our computation of gross receipts includes settled spot energy revenues and capacity revenues at each nuclear unit, and excludes any hedges. Treasury regulations are expected to further define the scope of the legislation in many important respects over the next year, including interpretive guidance on the definition of gross receipts for the nuclear PTC. Any interpretive guidance on the definition of gross receipts which differs from the interpretation used in our estimate could result in a material change to PTC revenues attributable to 2024 and would be reflected as a change in estimate in the period in which the guidance is received.

Transferable ITCs

In June 2023, our 350 MW battery ESS at our Moss Landing Power Plant site (Moss Landing Phase III) in California commenced commercial operations. As a result of Moss Landing Phase III meeting requirements to be placed in service in June 2023, we recognized $154 million of transferable ITCs associated with the project in other noncurrent assets in the consolidated balance sheet. In September 2024, we recognized an additional $2 million of transferable ITCs associated with the project and reclassified the $156 million of credits to other current assets.

In December 2024, our Baldwin 68 MW solar / 2 MW battery ESS and Coffeen 44 MW solar / 2 MW battery ESS facilities in Illinois met requirements to be placed in service. As a result, we recognized $57 million and $45 million of transferable ITCs associated with the projects, respectively, in other noncurrent assets in the consolidated balance sheet.

Sales of Transferable PTCs and ITCs

In October 2024, we sold $156 million of transferable ITCs and $10 million of transferable solar PTCs generated in 2023. Vistra received cash consideration from the sale in October 2024.

In January 2025, we sold $200 million of transferable nuclear PTCs we recognized from qualifying 2024 nuclear production. Cash consideration from the sale will be received in installments through July 2025 with an initial payment received in January 2025.

5. INCOME TAXES

Vistra files a U.S. federal income tax return that includes the results of its consolidated subsidiaries. Vistra serves as the corporate parent of the Vistra consolidated group. Pursuant to applicable U.S. Department of the Treasury regulations and published guidance of the IRS, corporations that are members of a consolidated group have joint and several liability for the taxes of such group.

Income Tax Expense (Benefit)

The components of our income tax expense (benefit) are as follows:

	Year Ended December 31, 2024	2023	2022
	(in millions)		
Current:			
U.S. Federal	$ 2	$ (1)	$ 2
State	46	52	7
Total current	48	51	9
Deferred:			
U.S. Federal	561	421	(304)
State	46	36	(55)
Total deferred	607	457	(359)
Total	$ 655	$ 508	$ (350)

Reconciliation of income taxes computed at the U.S. federal statutory rate to income tax expense (benefit) recorded:

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Income (loss) before income taxes	$ 3,467	$ 2,000	$ (1,560)
U.S. federal statutory rate	21 %	21 %	21 %
Income taxes at the U.S. federal statutory rate	728	420	(328)
State tax, net of federal benefit	80	86	(19)
Nondeductible TRA accretion	2	41	18
Transferable PTC revenues	(115)	(2)	—
Equity awards	(53)	(3)	(3)
Valuation allowance	(2)	(20)	(8)
Release of Uncertain Tax Positions	—	(35)	—
Other	15	21	(10)
Income tax expense (benefit)	$ 655	$ 508	$ (350)
Effective tax rate	18.9 %	25.4 %	22.4 %

Deferred Income Tax Balances

Deferred income taxes provided for temporary differences based on tax laws in effect at December 31, 2024 and 2023 are as follows:

	December 31,	
	2024	2023
	(in millions)	
Noncurrent Deferred Income Tax Assets		
Tax credit carryforwards	$ 86	$ 84
Loss carryforwards	949	1,081
Identifiable intangible assets	340	380
Long-term debt	225	173
Employee benefit obligations	133	117
Commodity contracts and interest rate swaps	383	664
Other	36	33
Total deferred tax assets	$ 2,152	$ 2,532
Noncurrent Deferred Income Tax Liabilities		
Property, plant, and equipment	2,765	1,264
Total deferred tax liabilities	2,765	1,264
Valuation allowance	75	46
Net Deferred Income Tax Asset (Liability)	$ (688)	$ 1,222

As of December 31, 2024, we had total net deferred tax liabilities of approximately $688 million that were substantially comprised of book and tax basis differences related to our generation and mining property, plant, and equipment, partially offset by federal and state net operating loss (NOL) carryforwards. Our net deferred tax liabilities were significantly impacted by the Energy Harbor Merger. For the years ended December 31, 2024 and 2023, we recognized tax benefits of $2 million and $20 million primarily related to the release of the federal valuation allowance on charitable contributions and state valuation allowances, respectively. As of December 31, 2024, we assessed the need for a valuation allowance related to our deferred tax asset and considered both positive and negative evidence related to the likelihood of realization of the deferred tax assets. We have identified positive evidence in the form of cumulative income on an unadjusted basis over the preceding 12 quarters. We evaluated historical earnings, performed scheduling of the reversal of temporary differences, and considered other positive and negative evidence. In connection with our analysis, we concluded that it is more likely than not that the federal deferred tax assets will be fully utilized by future taxable income, and thus no valuation allowance was required. A valuation allowance of approximately $30 million was recorded as part of Energy Harbor purchase accounting on state NOL carryforwards.

As of December 31, 2024, we had $3.2 billion pre-tax net operating loss (NOL) carryforwards for federal income tax purposes that will begin to expire in 2031.

The income tax effects of the components included in accumulated other comprehensive income totaled net deferred tax liabilities of $4 million and zero at December 31, 2024 and 2023, respectively.

IRA

In August 2022, the U.S. enacted the IRA, which, among other things, implements substantial new and modified energy tax credits, a 15% corporate alternative minimum tax (CAMT) on book income of certain large corporations, and a 1% excise tax on net stock repurchases. We do not expect Vistra to be subject to the CAMT in the 2024 tax year as it applies only to corporations with a three-year average annual adjusted financial statement income in excess of $1 billion. We have taken the CAMT and relevant extensions or expansions of existing tax credits applicable to projects in our immediate development pipeline into account when forecasting cash taxes. See Notes 1 and 4 for additional information.

Final Section 163(j) Regulations

The final Section 163(j) regulations, which limits qualified deductions for business interest expense, were issued in July 2020 and provided a critical correction to the proposed regulations regarding the computation of adjusted taxable income. As of January 1, 2022, certain provisions in the final Section 163(j) regulations have sunset, including the add-back of depreciation and amortization to adjusted taxable income. As a result, under the law as currently enacted, Vistra's deductible business interest expense was significantly limited for the 2024 tax year and will continue to be so limited under current law going forward. Vistra remains active in legislative monitoring and advocacy efforts to support a legislative solution to reinstate and make permanent the add-back of depreciation and amortization to adjusted taxable income.

Liability for Uncertain Tax Positions

Accounting guidance related to uncertain tax positions requires that all tax positions subject to uncertainty be reviewed and assessed with recognition and measurement of the tax benefit based on a "more-likely-than-not" standard with respect to the ultimate outcome, regardless of whether this assessment is favorable or unfavorable.

We classify interest and penalties related to uncertain tax positions as current income tax expense. The amounts were immaterial for the years ended December 31, 2024, 2023, and 2022. The following table summarizes the changes to the uncertain tax positions, reported in accumulated deferred income taxes and other current liabilities in the consolidated balance sheets for the years ended December 31, 2024, 2023, and 2022.

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Balance at beginning of period, excluding interest and penalties	$ —	$ 36	$ 38
Additions based on tax positions related to prior years	4	—	—
Reductions based on tax positions related to prior years	—	—	(1)
Reductions related to the lapse of the tax statute of limitations	—	(35)	—
Settlements with taxing authorities	—	(1)	(1)
Balance at end of period, excluding interest and penalties	$ 4	$ —	$ 36

Vistra and its subsidiaries file income tax returns in U.S. federal, state and foreign jurisdictions and are, at times, subject to examinations by the IRS and other taxing authorities. In February 2021, Vistra was notified that the IRS had opened a federal income tax audit for tax years 2018 and 2019. The federal income tax audit was closed in June 2023 with immaterial changes. Uncertain tax positions totaled $4 million and zero as of December 31, 2024 and 2023, respectively. Of the amounts recorded as unrecognized tax benefits, an insignificant portion would impact our effective tax rate if recognized.

Tax Matters Agreement

On the Effective Date, we entered into the Tax Matters Agreement with EFH Corp. whereby the parties have agreed to take certain actions and refrain from taking certain actions in order to preserve the intended tax treatment of the Spin-Off and to indemnify the other parties to the extent a breach of such agreement results in additional taxes to the other parties.

Among other things, the Tax Matters Agreement allocates the responsibility for taxes for periods prior to the Spin-Off between EFH Corp. and us. For periods prior to the Spin-Off: (a) Vistra is generally required to reimburse EFH Corp. with respect to any taxes paid by EFH Corp. that are attributable to us and (b) EFH Corp. is generally required to reimburse us with respect to any taxes paid by us that are attributable to EFH Corp.

We are also required to indemnify EFH Corp. against taxes, under certain circumstance, if the IRS or another taxing authority successfully challenges the amount of gain relating to the PrefCo Preferred Stock Sale or the amount or allowance of EFH Corp.'s net operating loss deductions.

Subject to certain exceptions, the Tax Matters Agreement prohibits us from taking certain actions that could reasonably be expected to undermine the intended tax treatment of the Spin-Off or to jeopardize the conclusions of the private letter ruling we obtained from the IRS or opinions of counsel received by us or EFH Corp., in each case, in connection with the Spin-Off. Certain of these restrictions apply for two years after the Spin-Off.

Under the Tax Matters Agreement, we may engage in an otherwise restricted action if (a) we obtain written consent from EFH Corp., (b) such action or transaction is described in or otherwise consistent with the facts in the private letter ruling we obtained from the IRS in connection with the Spin-Off, (c) we obtain a supplemental private letter ruling from the IRS, or (d) we obtain an unqualified opinion of a nationally recognized law or accounting firm that is reasonably acceptable to EFH Corp. that the action will not affect the intended tax treatment of the Spin-Off.

6. PROPERTY, PLANT, AND EQUIPMENT

Our property, plant, and equipment consist of our power generation assets, related mining assets, land, information system hardware, capitalized corporate office lease space and other leasehold improvements. The estimated remaining useful lives of our property, plant, and equipment ranges from 1 to 29 years. Land is not depreciated.

	December 31, 2024	December 31, 2023
	(in millions)	
Power generation and structures	$ 22,783	$ 17,297
Land	603	572
Office and other equipment	160	159
Total	23,546	18,028
Less accumulated depreciation	(8,020)	(6,657)
Net of accumulated depreciation	15,526	11,371
Finance lease right-of-use assets (net of accumulated amortization)	153	160
Nuclear fuel (net of accumulated amortization of $409 million and $120 million)	1,434	379
Construction work in progress	1,060	522
Property, plant, and equipment — net	$ 18,173	$ 12,432

Depreciation expenses totaled $1.670 billion, $1.344 billion, and $1.388 billion for the years ended December 31, 2024, 2023, and 2022, respectively.

Retirement of Generation Facilities

The following are all of our facilities that have either been retired, or that have announced retirement dates. Operation results for plants with defined retirement dates are included in our Asset Closure segment at the beginning of the calendar year the retirement is expected to occur.

Facility	Location	ISO/RTO	Fuel Type	Net Generation Capacity (MW)	Announced Retirement Date (a)	Segment
Baldwin	Baldwin, IL	MISO	Coal	1,185	By the end of 2027	East
Coleto Creek	Goliad, TX	ERCOT	Coal	650	By the end of 2027 (b)	Texas
Kincaid	Kincaid, IL	PJM	Coal	1,108	By the end of 2027	East
Miami Fort	North Bend, OH	PJM	Coal	1,020	By the end of 2027	East
Newton	Newton, IL	MISO	Coal	615	By the end of 2027	East
Edwards	Bartonville, IL	MISO	Coal	585	Retired January 1, 2023	Asset Closure
Joppa	Joppa, IL	MISO	Coal	802	Retired September 1, 2022	Asset Closure
Joppa	Joppa, IL	MISO	Natural Gas	221	Retired September 1, 2022	Asset Closure
Zimmer	Moscow, OH	PJM	Coal	1,300	Retired June 1, 2022	Asset Closure
Total				7,486		

(a) Generation facilities may retire earlier than expected dates disclosed if economic or other conditions dictate.
(b) Following the retirement of Coleto Creek as a coal-fueled plant, the Company intends to repower it as a gas-fueled plant.

Impairment of Long-Lived Assets

In the first quarter of 2023, we recognized an impairment loss of $49 million related to our Kincaid generation facility in Illinois as a result of a significant decrease in the projected operating margins of the facility, primarily driven by a decrease in projected power prices. The impairment is reported in our East segment and includes write-downs of property, plant, and equipment of $45 million, write-downs of inventory of $2 million, and write-downs of operating lease right-of-use assets of $2 million.

In the fourth quarter of 2022, we recognized an impairment loss of $74 million related to our Miami Fort generation facility in Ohio as a result of a significant decrease in the projected operating margins of the facility, reflecting an increase in projected coal costs along with a decrease in projected power prices. The impairment is reported in our East segment and includes write-downs of property, plant, and equipment of $71 million and write-downs of inventory of $3 million.

In determining the fair value of the impaired asset groups in 2023 and 2022, we utilized the income approach described in ASC 820, *Fair Value Measurement*.

7. GOODWILL AND IDENTIFIABLE INTANGIBLE ASSETS AND LIABILITIES

Goodwill

As of December 31, 2024 and 2023, the carrying value of goodwill totaled $2.807 billion and $2.583 billion, respectively.

	Retail Segment	Texas Segment	
	Retail Reporting Unit (a)	Texas Generation Reporting Unit	Total Goodwill
		(in millions)	
Balance at December 31, 2023	$ 2,461	$ 122	$ 2,583
Goodwill recorded in connection with the Energy Harbor Merger (b)			224
Balance at December 31 2024	$ 2,461	$ 122	$ 2,807

(a) Goodwill of $1.944 billion is deductible for tax purposes over 15 years on a straight-line basis.
(b) Allocation of goodwill attributable to the Energy Harbor acquisition to reporting units is pending completion of purchase accounting measurement period.

Goodwill is required to be evaluated for impairment at least annually or whenever events or changes in circumstances indicate an impairment may exist. We have selected October 1 as our annual goodwill test date. On the most recent goodwill testing date, we applied qualitative factors and determined that it was more likely than not that the fair value of our Retail and Texas Generation reporting units exceeded their carrying value at October 1, 2024. Significant qualitative factors evaluated included reporting unit financial performance and market multiples, general macroeconomic, industry, and market conditions, cost factors, customer attrition, interest rates, market capitalization, and changes in reporting unit book value.

Identifiable Intangible Assets and Liabilities

Identifiable intangible assets are comprised of the following:

	December 31, 2024			December 31, 2023		
Identifiable Intangible Asset	**Gross Carrying Amount**	**Accumulated Amortization**	**Net**	**Gross Carrying Amount**	**Accumulated Amortization**	**Net**
			(in millions)			
Retail customer relationship	$ 2,173	$ 1,977	$ 196	$ 2,088	$ 1,866	$ 222
Software and other technology-related assets	601	293	308	536	315	221
Retail and wholesale contracts	503	353	150	233	217	16
Long-term service agreements	18	5	13	18	5	13
Other identifiable intangible assets (a)	218	13	205	62	11	51
Total identifiable intangible assets subject to amortization	$ 3,513	$ 2,641	872	$ 2,937	$ 2,414	523
Retail trade names (not subject to amortization)			1,341			1,341
Total identifiable intangible assets			$ 2,213			$ 1,864

(a) Includes mining development costs and environmental allowances (emissions allowances and renewable energy certificates).

Identifiable intangible liabilities are comprised of the following:

	Year Ended December 31,	
Identifiable Intangible Liability	**2024**	**2023**
	(in millions)	
Long-term service agreements	$ 108	$ 122
Wholesale power and fuel purchase contracts	47	9
Total identifiable intangible liabilities	$ 155	$ 131

Amortization of finite-lived identifiable intangible assets and liabilities (including the classification in the consolidated statements of operations) consisted of:

Identifiable Intangible Assets/ Liabilities	Consolidated Statements of Operations	Remaining useful lives of identifiable intangible assets at December 31, 2024 (weighted average in years)	Year Ended December 31, 2024	2023	2022
			(in millions)		
Retail customer relationship	Depreciation and amortization	2	$ 111	$ 98	$ 137
Software and other technology-related assets	Depreciation and amortization	3	60	58	69
Retail and wholesale contracts	Operating revenues/Fuel, purchased power costs, and delivery fees	3	(12)	8	7
Other identifiable intangible assets	Fuel, purchased power costs, and delivery fees/ Depreciation and amortization	4	414	357	391
Total intangible asset expense, net			$ 573	$ 521	$ 604

Amounts recorded in depreciation and amortization totaled $173 million, $158 million, and $208 million for the years ended December 31, 2024, 2023, and 2022, respectively. Amounts include all expenses associated with environmental allowances including expenses accrued to comply with emissions allowance programs and renewable portfolio standards which are presented in fuel, purchased power costs, and delivery fees in the consolidated statements of operations. Emissions allowance obligations are accrued as associated electricity is generated and renewable energy certificate obligations are accrued as retail electricity delivery occurs.

The following is a description of the separately identifiable intangible assets recorded in fresh start reporting and in connection with purchase accounting from acquisitions.

- *Retail customer relationship* — Retail customer relationship intangible asset represents the fair value of our non-contracted retail customer base, including residential and business customers, and is amortized using an accelerated method based on historical customer attrition rates and reflecting the expected pattern in which economic benefits are realized over their estimated useful life.

- *Retail and wholesale contracts* — These intangible assets and liabilities represent the value of various acquired retail and wholesale contracts and fuel and transportation purchase contracts. The contracts were identified as either assets or liabilities based on the respective fair values utilizing prevailing market prices for commodities or services compared to the fixed prices contained in these agreements. The intangible assets or liabilities are amortized in relation to the economic terms of the related contracts.

- *LTSA* — Our acquired LTSA intangibles represent the estimated fair value of favorable or unfavorable contract obligations with respect to long-term plant maintenance agreements and are amortized based on the expected usage of the service agreements over the contract terms. The majority of the plant maintenance services relate to capital improvements and the related amortization of the plant maintenance agreements is recorded to property, plant, and equipment.

- *Retail trade names* — Our retail trade name intangible assets represent the fair value of our retail brands, including the trade names of TXU Energy™, Ambit Energy, 4Change Energy™, Homefield Energy, Dynegy Energy Services, TriEagle Energy, Public Power, and U.S. Gas & Electric, and were determined to be indefinite-lived assets not subject to amortization. These intangible assets are evaluated for impairment at least annually in accordance with accounting guidance related to other indefinite-lived intangible assets. We have selected October 1 as our test date. Significant qualitative factors evaluated included trade name financial performance, general macroeconomic, industry, and market conditions, customer attrition and interest rates. On the most recent testing date, we determined that it was more likely than not that the fair value of our retail trade name intangible asset exceeded its carrying value at October 1, 2024.

Estimated Amortization of Identifiable Intangible Assets

As of December 31, 2024, the estimated aggregate amortization expense of identifiable intangible assets, excluding environmental allowances, for each of the next five fiscal years is as shown below.

Year	Estimated Amortization Expense	
	(in millions)	
2025	$	231
2026	$	167
2027	$	72
2028	$	51
2029	$	34

8. COLLATERAL FINANCING AGREEMENT WITH AFFILIATE

On June 15, 2023, Vistra Operations entered into a facility agreement (Facility Agreement) with a Delaware trust formed by the Company (the Trust) that sold 450,000 pre-capitalized trust securities (P-Caps) redeemable May 17, 2028 for an initial purchase price of $450 million. The Trust is not consolidated by Vistra. The Trust invested the proceeds from the sale of the P-Caps in a portfolio of either (a) U.S. Treasury securities (Treasuries) or (b) Treasuries and/or principal and interest strips of Treasuries (Treasury Strips, and together with the Treasuries and cash denominated in U.S. dollars, the Eligible Assets). At the direction of Vistra Operations, the Eligible Assets held by the Trust can be (i) delivered to one or more designated subsidiaries of Vistra Operations in order to allow such subsidiaries to use the Eligible Assets to meet certain posting obligations with counterparties, and/or (ii) pledged as collateral support for a letter of credit program.

Under the Facility Agreement, Vistra Operations has the right (Issuance Right), from time to time, to require the Trust to purchase from Vistra Operations up to $450 million aggregate principal amount of Vistra Operations' 7.233% Senior Secured Notes due 2028 (7.233% Senior Secured Notes) in exchange for the delivery of all or a portion of the Treasuries and Treasury Strips corresponding to the portion of the issuance right exercised at such time.

The Trust will terminate at any time prior to May 17, 2028 and distribute the 7.233% Senior Secured Notes to the holders of the P-Caps if its sole assets consist of 7.233% Senior Secured Notes that Vistra Operations is no longer entitled to repurchase.

Vistra Operations pays a facility fee (Facility Fee) to the Trust payable on each May 17 and November 17, commencing on November 17, 2023, to and including May 17, 2028 (each, a Distribution Date), and on certain other dates as provided in the Facility Agreement. The Facility Fee is generally calculated at a rate of 3.3608% per annum, applied to the maximum amount of 7.233% Senior Secured Notes that Vistra Operations could issue and sell to the Trust under the Facility Agreement as of the close of business on the business day immediately preceding the applicable Distribution Date.

As of December 31, 2024 and 2023, the fair value of Eligible Assets held by counterparties to satisfy current and future margin deposit requirements totaled $435 million and $439 million, respectively, and is reported in the consolidated balance sheets as margin deposits posted under affiliate financing agreement and margin deposits financing with affiliate.

9. DEBT, CREDIT FACILITIES, AND FINANCINGS

Amounts in the table below represent the categories of debt obligations incurred by the Company.

	December 31, 2024	December 31, 2023
	(in millions)	
Long-term debt, including amounts due currently:		
Project-level debt	$ 1,064	$ —
Vistra Operations debt	15,405	14,517
Long-term debt before unamortized premiums, discounts, and issuance costs	16,469	14,517
Unamortized premiums, discounts, and issuance costs	(171)	(115)
Long-term debt including debt due currently	$ 16,298	$ 14,402
Accounts receivable financing	$ 750	$ —
Forward repurchase obligation	$ 1,335	$ —

Long-Term Debt

Amounts in the table below represent the categories of long-term debt obligations, including amounts due currently, incurred by the Company.

	December 31,	
	2024	2023
	(in millions)	
Vistra Operations Credit Facilities, Term Loan B-3 Facility due December 20, 2030	$ 2,475	$ 2,500
BCOP Credit Facility, Tax Credit Bridge Loan due November 1, 2025 / December 3, 2026	367	—
Vistra Zero Credit Facility, Term Loan B Facility due April 30, 2031	697	—
Vistra Operations Senior Secured Notes:		
4.875% Senior Secured Notes, due May 13, 2024	—	400
3.550% Senior Secured Notes, due July 15, 2024	—	1,500
5.125% Senior Secured Notes, due May 13, 2025	744	1,100
5.050% Senior Secured Notes, due December 30, 2026	500	—
3.700% Senior Secured Notes, due January 30, 2027	800	800
4.300% Senior Secured Notes, due July 15, 2029	800	800
6.950% Senior Secured Notes, due October 15, 2033	1,050	1,050
6.000% Senior Secured Notes, due April 15, 2034	500	—
5.700% Senior Secured Notes, due December 30, 2034	750	—
Total Vistra Operations Senior Secured Notes	5,144	5,650
Energy Harbor Revenue Bonds:		
3.375% Revenue Bond, due August 1, 2029	100	—
4.750% Revenue Bond, due June 1, 2033 and July 1, 2033	285	—
3.750% Revenue Bond, due October 1, 2047	46	—
Total Energy Harbor Revenue Bonds	431	—
Vistra Operations Senior Unsecured Notes:		
5.500% Senior Unsecured Notes, due September 1, 2026	1,000	1,000
5.625% Senior Unsecured Notes, due February 15, 2027	1,300	1,300
5.000% Senior Unsecured Notes, due July 31, 2027	1,300	1,300
4.375% Senior Unsecured Notes, due May 15, 2029	1,250	1,250
7.750% Senior Unsecured Notes, due October 15, 2031	1,450	1,450
6.875% Senior Unsecured Notes, due April 15, 2032	1,000	—
Total Vistra Operations Senior Unsecured Notes	7,300	6,300
Other:		
Equipment Financing Agreements	55	67
Total other long-term debt	55	67
Unamortized debt premiums, discounts, and issuance costs	(171)	(115)
Total long-term debt including amounts due currently	16,298	14,402
Less amounts due currently	(880)	(2,286)
Total long-term debt less amounts due currently	$ 15,418	$ 12,116

Long-Term Debt Maturities

Long-term debt maturities at December 31, 2024 are as follows:

		December 31, 2024
		(in millions)
2025	$	885
2026		1,792
2027		3,427
2028		27
2029		2,177
Thereafter		8,161
Unamortized premiums, discounts, and debt issuance costs		(171)
Total long-term debt, including amounts due currently	$	16,298

Credit Facilities

Our credit facilities and related available capacity at December 31, 2024 are presented below.

Credit Facilities	Maturity Date	December 31, 2024 Facility Limit	Cash Borrowings (Long-Term Debt, Including Amounts Due Currently)	Letters of Credit Outstanding	Available Capacity
		(in millions)			
Vistra Operations debt:					
Revolving Credit Facility	October 11, 2029	$ 3,440	$ —	$ 1,278	$ 2,162
Term Loan B-3 Facility	December 20, 2030	2,475	2,475	—	—
Total Vistra Operations Credit Facilities		$ 5,915	$ 2,475	$ 1,278	$ 2,162
Vistra Operations Commodity-Linked Facility	October 1, 2025	1,750	—	—	771
Total Vistra Operations debt		$ 7,665	$ 2,475	$ 1,278	$ 2,933
Project-level debt:					
Tax Credit Bridge Loan	November 1, 2025	106	106	—	—
Tax Credit Bridge Loan	December 3, 2026	261	261	—	—
BCOP Credit Facility		367	367	—	—
Vistra Zero Term Loan B Facility (a)	April 30, 2031	697	697	—	—
Total project-level debt		$ 1,064	$ 1,064	$ —	$ —
Total credit facilities		$ 8,729	$ 3,539	$ 1,278	$ 2,933

(a) Vistra Zero Operations' obligations under the Vistra Zero Credit Agreement are guaranteed by subsidiaries of Vistra Zero Operations, but are otherwise non-recourse to Vistra Operations and its other subsidiaries.

Vistra Operations Credit Facilities

Vistra maintains credit facilities with certain financial institutions and, as of December 31, 2024, has aggregate commitments of up to $5.915 billion in senior secured, first-lien revolving credit commitments and outstanding term loans (Vistra Operations Credit Facilities). The Vistra Operations Credit Facilities consist of (i) revolving credit commitments of up to $3.440 billion, including aggregate revolving letter of credit commitments of up to $3.440 billion (Revolving Credit Facility), and (ii) term loans of $2.475 billion (Term Loan B-3 Facility). These amounts reflect the following transactions and amendments completed in 2024:

Amendment Date	Key Changes
December 2024	Lowered fixed spread on Term Loan B-3 Facility borrowings from 2.00% to 1.75%
October 2024	Increased Revolving Credit Facility commitments from $3.175 billion to $3.440 billion
	Extended the maturity date of the Revolving Credit Facility to October 11, 2029

Revolving Credit Facility — The Revolving Credit Facility is used for general corporate purposes. Under the Vistra Operations Credit Agreement, the interest on borrowings under the Revolving Credit Facility is paid based on (i) the forward-looking term rate based on SOFR (Term SOFR) plus a spread that will range from 1.25% to 2.00% and (ii) the fee on any undrawn amounts with respect to the Revolving Credit Facility ranges from 17.5 basis points to 35.0 basis points. Interest periods for Term SOFR borrowings are for a one-, three-, or six-month periods with interest paid in arrears. Letters of credit issued under the Revolving Credit Facility bear interest that ranges from 1.25% to 2.00% and are paid quarterly in arrears. Interest and fees on the Revolving Credit Facility are based on ratings of Vistra Operations' senior secured long-term debt securities. As of December 31, 2024, after taking into account sustainability pricing adjustments based on certain sustainability-linked targets and thresholds, the applicable interest rate margins for the Revolving Credit Facility and the fee for undrawn amounts relating to such commitments were 1.725% and 27.0 basis points, respectively, and the applicable interest rate margin for the letters of credit issued under the Revolving Credit Facility was 1.725%.

Term Loan B-3 Facility — The Term Loan B-3 Facility is used for general corporate purposes and bears interest based on the applicable Term SOFR, plus a fixed spread of 2.00% through December 9, 2024 and 1.75% thereafter, and the weighted average interest rates before taking into consideration interest rate swaps (see Note 11) on outstanding borrowings of $2.475 billion was 6.11% as of December 31, 2024. Interest periods for Term SOFR loans are for a one-, three-, or six-month periods with interest paid in arrears. Cash borrowings under the Term Loan B-3 Facility are subject to required scheduled quarterly payments of $6.25 million. Amounts paid cannot be reborrowed.

Other Information — Obligations under the Vistra Operations Credit Facilities are secured by liens covering substantially all of Vistra Operations' (and certain of its subsidiaries') consolidated assets, rights and properties, subject to certain exceptions set forth in the Vistra Operations Credit Facilities. The Vistra Operations Credit Agreement includes certain collateral suspension provisions that would take effect upon Vistra Operations achieving unsecured investment grade ratings from two ratings agencies and there being no Term Loans (under and as defined in the Vistra Operations Credit Agreement) then outstanding (or the holders thereof agreeing to release such security interests). Such collateral suspension provisions would continue to be in effect unless and until Vistra Operations no longer holds unsecured investment grade ratings from at least two ratings agencies, at which point collateral reversion provisions would take effect (subject to a 60-day grace period).

The Vistra Operations Credit Facilities also permit certain hedging agreements and cash management agreements to be secured on a pari-passu basis with the Vistra Operations Credit Facilities in the event those hedging agreements and cash management agreements meet certain criteria set forth in the Vistra Operations Credit Facilities.

The Vistra Operations Credit Facilities provide for affirmative and negative covenants applicable to Vistra Operations (and its restricted subsidiaries), including affirmative covenants requiring it to provide financial and other information to the agent under the Vistra Operations Credit Facilities and to not change its lines of business, and negative covenants restricting Vistra Operations' (and its restricted subsidiaries') ability to incur additional indebtedness, make investments, dispose of assets, pay dividends, grant liens or take certain other actions, in each case, except as permitted in the Vistra Operations Credit Facilities. The Vistra Operations Credit Agreement also includes a springing financial covenant with respect to the Revolving Credit Facility that, when applicable, would require compliance with a consolidated first lien net leverage ratio. Vistra Operations' ability to borrow under the Vistra Operations Credit Facilities is subject to the satisfaction of certain customary conditions precedent set forth therein.

The Vistra Operations Credit Facilities provide for certain customary events of default, including events of default resulting from non-payment of principal, interest, or fees when due, material breaches of representations and warranties, breaches of covenants in the Vistra Operations Credit Facilities or ancillary loan documents, cross-defaults under other agreements or instruments and the existence of material unpaid (or unstayed) judgments against Vistra Operations and certain of its subsidiaries. Upon the existence of an event of default, the Vistra Operations Credit Facilities provide that all principal, interest and other amounts due thereunder will become immediately due and payable, either automatically or at the election of specified lenders.

The Vistra Operations Credit Agreement generally restricts the ability of Vistra Operations to make distributions to any direct or indirect parent unless such distributions are expressly permitted thereunder. As of December 31, 2024, Vistra Operations can distribute approximately $8.2 billion to Parent under the Vistra Operations Credit Agreement without the consent of any party. The amount that can be distributed by Vistra Operations to Parent was partially reduced by distributions made by Vistra Operations to Parent of approximately $1.705 billion, $1.625 billion, and $1.775 billion during the years ended December 31, 2024, 2023, and 2022, respectively. Additionally, Vistra Operations may make distributions to Parent in amounts sufficient for Parent to pay any taxes or general operating or corporate overhead expenses arising out of Parent's ownership or operation of Vistra Operations. As of December 31, 2024, all of the restricted net assets of Vistra Operations may be distributed to Parent.

Vistra Operations Commodity-Linked Revolving Credit Facility

As of December 31, 2024, Vistra Operations senior secured commodity-linked revolving credit facility (Commodity-Linked Facility) totaled $1.75 billion of aggregate available commitments. We have the flexibility, subject to our ability to obtain additional commitments, to further increase the size of the Commodity-Linked Facility to $3.0 billion. As of December 31, 2024, the borrowing base of $771 million is lower than the facility limit which represents the aggregate commitments of $1.75 billion. These amounts reflect the following amendment completed in 2024:

Amendment Date	Key Changes
October 2024	Increased the aggregate available commitments to $1.75 billion
	Extended the maturity date to October 1, 2025

Under the Commodity-Linked Facility, the borrowing base is calculated on a weekly basis based on a set of theoretical transactions which approximate a portion of the hedge portfolio of Vistra Operations and certain of its subsidiaries in certain power markets, with availability thereunder not to exceed the aggregate available commitments nor be less than zero. Vistra Operations may, at its option, borrow an amount up to the borrowing base, as adjusted from time to time, provided that if outstanding borrowings at any time would exceed the borrowing base, Vistra Operations shall make a repayment to reduce outstanding borrowings to be less than or equal to the borrowing base. Vistra Operations intends to use any borrowings provided under the Commodity-Linked Facility to make cash postings as required under various commodity contracts to which Vistra Operations and its subsidiaries are parties as power prices increase from time-to time and for other working capital and general corporate purposes.

Interest on the Commodity-Linked Facility bears interest (i) based on either the Term SOFR or a daily simple SOFR rate, (ii) a spread that ranges from 1.25% to 2.00%, and (iii) sustainability pricing adjustments based on certain sustainability-linked targets and thresholds. Interest periods for Term SOFR borrowings are for a one-, three-, or six-month periods with interest paid in arrears. The interest period for a daily simple SOFR is for a one-week period with interest paid in arrears. The fee on any undrawn amounts with respect to the Commodity-Linked Facility ranges from 17.5 basis points to 35.0 basis points. As of December 31, 2024, the applicable interest rate margins for borrowings outstanding under the Commodity-Linked Facility was 1.725% and the fee on any undrawn amounts with respect to the Commodity-Linked Facility was 27.0 basis points. Interest and fees on the Commodity-Linked Facility are based on ratings of Vistra Operations' senior secured long-term debt securities.

BCOP Project-level Credit Facilities

In December 2024, BCOP and its subsidiaries entered into the BCOP Credit Agreement to fund the development of the Baldwin and Coffeen solar generation and battery ESS facilities and the Oak Hill and Pulaski solar generation facilities in Illinois and Texas. The BCOP Credit Agreement provides for (i) tax credit bridge loans of $367 million for the Oak Hill and Pulaski projects (Tax Credit Bridge Loans) and (ii) construction/term loan commitments of $528 million and debt service reserve letter of credit facility commitments of $29 million for all four facilities.

At December 31, 2024, the Tax Credit Bridge Loans for Oak Hill and Pulaski totaled $106 million and $261 million, respectively, and mature in November 2025 and December 2026, respectively, subject to the terms of the BCOP Credit Agreement. The weighted average interest rate on outstanding borrowings was 5.984% at December 31, 2024. Repayment of the Tax Credit Bridge Loans are guaranteed by Vistra as the beneficiary of the underlying investment tax credits to be generated by the projects. At December 31, 2024, there were no construction/term loan borrowings outstanding or debt service reserve letters of credit issued.

Interest is paid on the Tax Credit Bridge Loan in arrears based on the applicable Term SOFR rate elected in the borrowing notice plus a fixed spread of 1.625% per annum. Interest on the construction/term loans will be paid in arrears based on the applicable Term SOFR rate elected in the borrowing notice plus fixed spreads of 1.875% per annum for construction loans and 2.000% per annum for term loans. Fees on the debt service reserve letter of credit loans will be paid in arrears at 2.000% per annum. Commitment fees on the undrawn loan commitments and unissued letter of credit commitments will pay quarterly in arrears at a fixed percentage of the loan's fixed spread.

Vistra Zero Project-level Credit Agreement

In March 2024, Vistra Zero Operations entered into the Vistra Zero Credit Agreement. The Vistra Zero Credit Agreement provides for a senior secured term loan (Term Loan B Facility) of up to $700 million, which Vistra Zero Operations borrowed in its entirety in March 2024. Net proceeds of $690 million were used (i) to pay issuance costs and (ii) for working capital and general corporate purposes. Vistra Zero Operations' obligations under the Vistra Zero Credit Agreement are guaranteed by subsidiaries of Vistra Zero Operations, but are otherwise non-recourse to Vistra Operations and its other subsidiaries. These amounts reflect the following amendment completed in 2024:

Amendment Date	Key Changes
December 2024	Lowered the fixed spread interest applicable to the Term Loan B Facility from 2.75% to 2.00%
	Removed required scheduled quarterly payment requirements

Interest on the Term Loan B Facility is based on Term SOFR plus 2.75% per year through December 16, 2024. The December 2024 amendment lowered the fixed spread on this instrument to 2.00% thereafter. Interest periods for Term SOFR loans are for a one-, three-, or six-month periods with interest paid in arrears. The weighted average interest rates before taking into consideration interest rate swaps on outstanding borrowings of $697 million was 6.36% as of December 31, 2024.

The Vistra Zero Credit Agreement contains customary covenants and warranties which are generally consistent in scope with the Vistra Operations Credit Agreement, except that there is no financial maintenance covenant in the Vistra Zero Credit Agreement.

Letter of Credit Facilities

Vistra Operations Secured Letter of Credit Facilities

Between August 2020 and July 2024, we entered into uncommitted standby letter of credit facilities with various banks (each, a Secured LOC Facility and collectively, the Secured LOC Facilities). The Secured LOC Facilities are secured by a first lien on substantially all of Vistra Operations' (and certain of its subsidiaries') assets (which ranks pari passu with the Vistra Operations Credit Facilities). The Secured LOC Facilities may be renewed annually and are used for general corporate purposes. As of December 31, 2024, $1.157 billion of letters of credit were outstanding under the Secured LOC Facilities.

Vistra Operations Unsecured Alternative Letter of Credit Facilities

In March 2024, we entered into unsecured alternative letter of credit facilities (Alternative LOC Facilities) to be used for general corporate purposes. In May 2024, the Alternative LOC Facilities were amended to increase the commitment cap to a total of $500 million. As of December 31, 2024, the total capacity was $500 million and $500 million of letters of credit were outstanding under the Alternative LOC Facilities. The commitments under the Alternative LOC Facilities terminate in December 2028. There are no financial maintenance covenants in the Alternative LOC Facilities.

Vistra Operations Senior Secured Notes

Vistra Operations issues and sells its senior secured notes in offerings to eligible purchasers under Rule 144A and Regulation S under the Securities Act (collectively, the Senior Secured Notes). The indenture (as may be amended or supplemented from time to time, the Vistra Operations Senior Secured Indenture) governing the Senior Secured Notes provides for the full and unconditional guarantee by certain of Vistra Operations' current and future subsidiaries that also guarantee the Vistra Operations Credit Facilities. The Senior Secured Notes are secured by a first-priority security interest in the same collateral that is pledged for the benefit of the lenders under the Vistra Operations Credit Facilities and contains certain covenants and restrictions consistent with the Vistra Operations Credit Facilities.

In December 2024, Vistra Operations issued $1.25 billion aggregate principal amount of senior secured notes, consisting of $500 million aggregate principal amount of 5.050% senior secured notes due 2026 (5.050% Senior Secured Notes) and $750 million aggregate principal amount of 5.700% senior secured notes due 2034 (5.700% Senior Secured Notes) in an offering to eligible purchasers under Rule 144A and Regulation S under the Securities Act. Interest is payable in cash semiannually in arrears on June 30 and December 30 beginning June 30, 2025. Net proceeds totaling approximately $1.240 billion, together with cash on hand, will be used for (i) general corporate purposes, including to refinance outstanding indebtedness (including 2025 debt maturities), (ii) to fund the opportunistic early payout of the purchase price installment payments scheduled to be paid in 2025 and 2026 to Avenue for the acquisition of the noncontrolling interest in Vistra Vision and (iii) to pay fees and expenses related to the offering.

In May 2024 and July 2024, the 4.875% senior secured notes due May 2024 and 3.550% senior secured notes due July 2024, respectively, were repaid at maturity.

In April 2024, Vistra Operations issued $500 million aggregate principal amount of 6.000% senior secured notes due 2034 (6.000% Senior Secured Notes) in an offering to eligible purchasers under Rule 144A and Regulation S under the Securities Act. Interest is payable in cash semiannually in arrears on April 15 and October 15 beginning October 15, 2024. Net proceeds totaling approximately $495 million, together with proceeds from the April 2024 issuance of 6.875% Senior Unsecured Notes discussed below and cash on hand, were to be used for general corporate purposes, including to refinance outstanding indebtedness (the senior secured debt maturities in May 2024 and July 2024).

Energy Harbor Revenue Bonds

Various governmental entities in Ohio and Pennsylvania have issued multiple tranches of revenue bonds for the benefit of Energy Harbor Generation LLC (EHG) or Energy Harbor Nuclear Generation LLC (EHNG); (collectively, the EH entities), in an aggregate principal amount of $431 million. The relevant EH entity is obligated to provide contractual payments to the applicable issuer of the revenue bonds to service the principal and interest on the revenue bonds, the payment of which is indirectly secured by all or substantially all of the assets of the EH entities under various mortgage bonds issued by the EH entities. In the event of a default by the EH entities of their contractual obligation to pay principal and interest in respect of the revenue bonds, the trustee of the revenue bonds would be able to call the mortgage bonds due and, if unpaid, foreclose on the assets securing the mortgage bonds. The obligations of the EH entities in respect of the revenue bonds and related mortgage bonds are guaranteed on an unsecured basis by Energy Harbor and Vistra.

Vistra Operations Senior Unsecured Notes

Vistra Operations issues and sells its senior unsecured notes in offerings to eligible purchasers under Rule 144A and Regulation S under the Securities Act (collectively, the Senior Unsecured Notes). The indentures (as may be amended or supplemented from time to time, the Vistra Operations Senior Unsecured Indentures) governing the Senior Unsecured Notes provide for the full and unconditional guarantee by the Guarantor Subsidiaries. The Vistra Operations Senior Unsecured Indentures contain certain covenants and restrictions, including, among others, restrictions on the ability of Vistra Operations and its subsidiaries, as applicable, to create certain liens, merge or consolidate with another entity, and sell all or substantially all of their assets.

In April 2024, Vistra Operations issued $1.0 billion aggregate principal amount of 6.875% senior unsecured notes due 2032 (6.875% Senior Unsecured Notes) in an offering to eligible purchasers under Rule 144A and Regulation S under the Securities Act. Interest is payable in cash semiannually in arrears on April 15 and October 15 beginning October 15, 2024. Net proceeds totaling approximately $990 million, together with proceeds from the April 2024 issuance of 6.000% Senior Secured Notes discussed above and cash on hand, were to be used for general corporate purposes, including to refinance outstanding indebtedness (including the senior secured debt maturities in May 2024 and July 2024).

Other Debt Activity

Senior Secured Notes Tender Offer

In January 2024, Vistra Operations used the net proceeds from (i) the December 2023 issuances of the 6.950% senior secured notes due 2033 and 7.750% senior unsecured notes due 2031 and (ii) cash on hand, to fund a cash tender offer (Senior Secured Notes Tender Offer) to purchase for cash $759 million aggregate principal amount of certain notes, including $58 million of 4.875% senior secured notes due 2024, $345 million of 3.550% senior secured notes due 2024 and $356 million of the 5.125% senior secured notes due 2025. We recorded an extinguishment gain of $6 million on the transaction in the first quarter of 2024.

Accounts Receivable Financing

Accounts Receivable Securitization Program

TXU Energy Receivables Company LLC (RecCo), an indirect subsidiary of Vistra, has an accounts receivable financing facility (Receivables Facility) provided by issuers of asset-backed commercial paper and commercial banks (Purchasers). In April 2024, the Receivables Facility was amended to increase the purchase limit from $750 million to $1.0 billion and to add Energy Harbor LLC, a direct, wholly owned subsidiary of Energy Harbor, as an Originator. The Receivables Facility was renewed and amended in July 2024, extending the term of the Receivables Facility to July 2025.

In connection with the Receivables Facility, TXU Energy, Dynegy Energy Services, Ambit Texas, Value Based Brands, Energy Harbor LLC and TriEagle Energy, each indirect subsidiaries of Vistra and originators under the Receivables Facility (Originators), each sell and/or contribute, subject to certain exclusions, all of its receivables (other than any receivables excluded pursuant to the terms of the Receivables Facility), arising from the sale of electricity to its customers and related rights (Receivables), to RecCo, a consolidated, wholly owned, bankruptcy-remote, direct subsidiary of TXU Energy. RecCo, in turn, is subject to certain conditions, and may draw under the Receivables Facility up to the limit described above to fund its acquisition of the Receivables from the Originators. RecCo has granted a security interest on the Receivables and all related assets for the benefit of the Purchasers under the Receivables Facility and Vistra Operations has agreed to guarantee the performance of the obligations of the Originators and TXU Energy, as the servicer, under the agreements governing the Receivables Facility. Amounts funded by the Purchasers to RecCo are reflected as short-term borrowings in the consolidated balance sheets. Proceeds and repayments under the Receivables Facility are reflected as cash flows from financing activities in the consolidated statements of cash flows. Receivables transferred to the Purchasers remain on Vistra's balance sheet and Vistra reflects a liability equal to the amount advanced by the Purchasers. The Company records interest expense on amounts advanced. TXU Energy continues to service, administer and collect the Receivables on behalf of RecCo and the Purchasers, as applicable.

As of December 31, 2024, outstanding borrowings under the Receivables Facility totaled $750 million and were supported by $1.334 billion of RecCo gross receivables. As of December 31, 2023, there were no outstanding borrowings under the Receivables Facility.

Repurchase Facility

TXU Energy and the other Originators under the Receivables Facility have a repurchase facility (Repurchase Facility) that is provided on an uncommitted basis by a commercial bank as buyer (Buyer). In July 2024, the Repurchase Facility was renewed until July 2025 while maintaining the facility size of $125 million. The Repurchase Facility is collateralized by a subordinated note (Subordinated Note) issued by RecCo in favor of TXU Energy for the benefit of Originators under the Receivables Facility and representing a portion of the outstanding balance of the purchase price paid for the Receivables sold by the Originators to RecCo under the Receivables Facility. Under the Repurchase Facility, TXU Energy may request that Buyer transfer funds to TXU Energy in exchange for a transfer of the Subordinated Note, with a simultaneous agreement by TXU Energy to transfer funds to Buyer at a date certain or on demand in exchange for the return of the Subordinated Note (collectively, the Repo Transaction). Each Repo Transaction is expected to have a term of one month, unless terminated earlier on demand by TXU Energy or terminated by Buyer after an event of default.

TXU Energy and the other Originators have each granted Buyer a first-priority security interest in the Subordinated Note to secure its obligations under the agreements governing the Repurchase Facility, and Vistra Operations has agreed to guarantee the obligations under the agreements governing the Repurchase Facility. Unless earlier terminated under the agreements governing the Repurchase Facility, the Repurchase Facility will terminate concurrently with the scheduled termination of the Receivables Facility.

There were no outstanding borrowings under the Repurchase Facility as of both December 31, 2024 and December 31, 2023.

Forward Repurchase Obligation

In accordance with the amended UPAs, on December 31, 2024, Vistra closed the acquisition of the Vistra Vision minority interests from Avenue and Nuveen. Vistra paid Avenue for the purchase of their minority interest in Vistra Vision in full upon closing and paid Nuveen an initial payment at closing, with the remaining payments to Nuveen to be paid in multiple installments through December 31, 2026. Vistra Vision Holdings' remaining future payments to Nuveen are guaranteed by Vistra Operations and certain of its subsidiaries that guarantee Vistra Operations' unsecured notes. Payments remaining due to Nuveen are as follows:

	December 31, 2024
	(in millions)
2025	$ 781
2026	669
Thereafter	—
Total scheduled payments under the UPAs	$ 1,450

A roll-forward of the noncontrolling interest redemption obligation is as follows (in millions):

Redeemable noncontrolling interest at September 30, 2024	$ 3,198
Income attributable to redeemable noncontrolling interest (a)	51
Dividends to redeemable noncontrolling interest holders	(165)
Redeemable noncontrolling interest balance at Closing Date (b)	3,084
Principal payment on Closing Date	(1,749)
Forward Repurchase Obligation at December 31, 2024 (c)	$ 1,335

(a) Represents accretion attributable to fixed price redemption obligation.
(b) Reclassified to a financing obligation.
(c) Fair value of the remaining payment obligations to Nuveen discounted at 6%.

Interest Expense and Related Charges

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Interest expense	$ 936	$ 654	$ 591
Unrealized mark-to-market net (gains) losses on interest rate swaps	(53)	36	(250)
Amortization of debt issuance costs, discounts, and premiums	34	26	28
Facility Fee expense	15	8	—
Debt extinguishment gain	(6)	(3)	(1)
Capitalized interest	(77)	(37)	(29)
Other	51	56	29
Total interest expense and related charges	$ 900	$ 740	$ 368

The weighted average interest rate applicable to the Vistra Operations Credit Facilities, taking into account the interest rate swaps discussed in Note 11, was 5.23%, 5.69%, and 4.30% as of December 31, 2024, 2023, and 2022, respectively.

10. LEASES

Vistra has both finance and operating leases for real estate, rail cars and equipment. Our leases have remaining lease terms for 1 to 42 years. Our leases include options to renew up to 17 years. Certain leases also contain options to terminate the lease.

Lease Cost

The following table presents costs related to lease activities:

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Operating lease cost	$ 17	$ 12	$ 9
Finance lease:			
Finance lease right-of-use asset amortization	8	10	9
Interest on lease liabilities	11	11	12
Total finance lease cost	19	21	21
Variable lease cost (a)	29	37	22
Short-term lease cost	56	44	47
Total lease cost	$ 121	$ 114	$ 99

(a) Represents coal stockpile management services, common area maintenance services, and rail car payments based on the number of rail cars used.

Balance Sheet Information

The following table presents lease related balance sheet information:

	December 31,	
	2024	2023
	(in millions)	
Lease assets:		
Operating lease right-of-use assets (reported in other noncurrent assets in the consolidated balance sheets)	$ 106	$ 50
Finance lease right-of-use assets, net of accumulated amortization (reported in property, plant, and equipment in the consolidated balance sheets)	153	$ 160
Total lease right-of-use assets	$ 259	$ 210
Current lease liabilities (reported in other current liabilities in the consolidated balance sheets):		
Operating lease liabilities	$ 13	$ 7
Finance lease liabilities	9	9
Total current lease liabilities	22	16
Noncurrent lease liabilities (reported in other noncurrent liabilities and deferred credits in the consolidated balance sheets):		
Operating lease liabilities	98	48
Finance lease liabilities	218	227
Total noncurrent lease liabilities	316	275
Total lease liabilities	$ 338	$ 291

Supplemental Cash Flow Information

The following table presents lease related cash flows and other information:

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Non-cash disclosure upon commencement of new lease:			
Right-of-use assets obtained in exchange for new operating lease liabilities	68	3	19
Right-of-use assets obtained in exchange for new finance lease liabilities	—	—	6
Non-cash disclosure upon modification of existing lease:			
Modification of operating lease right-of-use assets	1	7	—
Modification of finance lease right-of-use assets	—	(1)	4

Weighted Average Remaining Lease Term

The following table presents weighted average remaining lease term information:

	December 31,	
	2024	2023
Weighted average remaining lease term:		
Operating lease	23.8 years	20.1 years
Finance lease	23.7 years	24.0 years
Weighted average discount rate:		
Operating lease	7.85%	6.49 %
Finance lease	4.82%	4.81 %

Maturity of Lease Liabilities

The following table presents maturity of lease liabilities:

	Operating Lease	Finance Lease	Total Lease
		(in millions)	
2025	$ 19	$ 19	$ 38
2026	13	14	27
2027	14	13	27
2028	10	13	23
2029	8	13	21
Thereafter	222	331	553
Total lease payments	286	403	689
Less: Imputed interest	(175)	(176)	(351)
Present value of lease liabilities	$ 111	$ 227	$ 338

11. DERIVATIVES

We utilize derivative instruments, such as options, swaps, futures, and forward contracts to manage our exposure to commodity price and interest rate volatility. Counterparties to these transactions include energy companies, financial institutions, electric utilities, independent power producers, fuel oil and natural gas producers, local distribution companies, and energy marketing companies.

Commodity Derivatives

We utilize financial natural gas and financial and physical electricity derivatives to reduce exposure to changes in electricity prices primarily to hedge future revenues from electricity sales from our generation assets. Financial transmission rights and congestion revenue rights are derivative instruments we utilize to hedge electricity price differences between settlement points within regions. Gains and losses associated with these derivatives are reported in the consolidated statements of operations in operating revenues.

We utilize physical natural gas, coal, emissions, and renewable energy certificate derivatives primarily to hedge future purchased power costs of our retail operations or fuel costs of our generation assets. Gains and losses associated with these derivatives are reported in the consolidated statements of operations in fuel, purchased power costs, and delivery fees.

Our retail segment procures power from our generation segments to serve future load obligations. In locations and periods where our load service activities do not naturally offset existing generation portfolio risks, remaining commodity price exposure is managed through portfolio hedging activities.

Interest Rate Swaps

Interest rate swap agreements are used to reduce exposure to interest rate changes by converting floating-rate interest rates to fixed rates, thereby hedging future interest costs and related cash flows. Gains and losses associated with these derivatives are reported in the consolidated statements of operations in interest expense and related charges.

As of December 31, 2024, Vistra has entered into the following interest rate swaps:

	Notional Amount	Expiration Date	Rate Range (c)
		(in millions, except percentages)	
Swapped to fixed (a)	$3,000	July 2026	4.64 % - 4.72%
Swapped to variable (a)	$700	July 2026	3.19 % - 3.24%
Swapped to fixed (b)	$2,300	December 2030	4.95 % - 5.51%

(a) The $700 million of pay variable rate and receive fixed rate swaps match the terms of a portion of the $3.0 billion pay fixed rate and receive variable rate swaps. These matched swaps will settle over time and effectively offset the hedged position. These offsetting swaps expiring in July 2026 hedge our exposure on $2.3 billion of variable rate debt through July 2026.
(b) Effective from July 2026 through December 2030.
(c) The rate ranges reflect the fixed leg of each swap at a Term SOFR rate plus an interest margin of 1.75%.

In November 2024, Vistra entered into $675 million notional amount of interest rate swaps effective July 31, 2026 and expiring on December 31, 2030. These swaps, along with $1.625 billion notional amount of interest rate swaps with similar terms entered into in 2023, will hedge our exposure on $2.3 billion of floating rate debt from August 2026 through December 2030.

Effect of Derivative Instruments in the Consolidated Balance Sheets

We maintain standardized master netting agreements with certain counterparties that allow for the right to offset accounts payable, accounts receivable and cash collateral paid in order to reduce credit exposure. The following tables reconcile our gross derivative assets and liabilities as reported in the consolidated balance sheets to the net value on a contract basis, after taking into consideration netting arrangements with counterparties and cash collateral recorded.

	December 31, 2024				
	Derivative Contract Assets		Derivative Contract Liabilities		
	Commodity Contracts	Interest Rate Swaps	Commodity Contracts	Interest Rate Swaps	Total
	(in millions)				
Current assets	$ 2,551	$ 34	$ 2	$ —	$ 2,587
Noncurrent assets	677	62	1	—	740
Current liabilities	—	—	(3,333)	(18)	(3,351)
Noncurrent liabilities	(2)	—	(1,356)	(9)	(1,367)
Net assets (liabilities)	$ 3,226	$ 96	$ (4,686)	$ (27)	$ (1,391)
Offsetting instruments (a)	$ (2,532)	$ (28)	$ 2,532	$ 28	—
Financial collateral (received) pledged (b)	$ (50)	$ —	$ 233	$ —	183
Net amounts	$ 644	$ 68	$ (1,921)	$ 1	$ (1,208)

	December 31, 2023				
	Derivative Contract Assets		Derivative Contract Liabilities		
	Commodity Contracts	Interest Rate Swaps	Commodity Contracts	Interest Rate Swaps	Total
	(in millions)				
Current assets	$ 3,585	$ 53	$ 7	$ —	$ 3,645
Noncurrent assets	565	11	1	—	577
Current liabilities	(1)	—	(5,233)	(24)	(5,258)
Noncurrent liabilities	(5)	—	(1,659)	(24)	(1,688)
Net assets (liabilities)	$ 4,144	$ 64	$ (6,884)	$ (48)	$ (2,724)
Offsetting instruments (a)	$ (3,519)	$ (28)	$ 3,519	$ 28	—
Financial collateral (received) pledged (b)	$ (26)	$ —	$ 970	$ —	944
Net amounts	$ 599	$ 36	$ (2,395)	$ (20)	$ (1,780)

(a) Amounts presented exclude trade accounts receivable and payable related to settled financial instruments.

(b) Represents cash amounts received or pledged pursuant to a master netting arrangement, including fair value-based margin requirements, and, to a lesser extent, initial margin requirements.

Effect of Derivative Instruments in the Consolidated Statements of Operations

The following table summarizes the location and amount of unrealized gains and losses from our derivative instruments recorded in the consolidated statements of operations for the periods presented.

Derivative (consolidated statements of operations presentation)	Year Ended December 31, 2024	2023	2022
		(in millions)	
Reversals of previously recognized unrealized (gain) loss on derivative instruments:			
Commodity contracts unrealized (gain) loss in operating revenues (a)	$ 1,140	$ 1,472	$ 1,940
Commodity contracts unrealized (gain) loss in fuel and purchased power expense (a)	73	171	(722)
Interest rate swaps unrealized (gain) loss in interest expense and related charges	(41)	(78)	16
Total reversals of previously recognized unrealized (gain) loss on derivative instruments	$ 1,172	$ 1,565	$ 1,234
Unrealized net gains (losses) from changes in fair value on derivative instruments:			
Commodity contracts unrealized gain (loss) in operating revenues	$ (127)	$ (758)	$ (4,103)
Commodity contracts unrealized gain (loss) in fuel and purchased power expense	69	(395)	375
Interest rate swaps unrealized gain (loss) in interest expense and related charges	94	42	234
Total unrealized net gains (losses) from changes in fair value on derivative instruments	$ 36	$ (1,111)	$ (3,494)
Net gain (loss) on derivative instruments	$ 1,208	$ 454	$ (2,260)

(a) Excludes the realized effects of changes in fair value in the month the position settled, amounts related to positions entered into and settled in the same month, and physical retail and wholesale contracts accounted for as derivatives which did not financially settle but realized at the contract's notional and price. The realized effects of these items are included in operating revenues and fuel and purchased power expense.

Derivative Volumes

The following table presents the gross notional amounts of derivative volumes by commodity, excluding our NPNS derivatives that are not recorded at fair value:

Derivative type	December 31, 2024	December 31, 2023	Unit of Measure
	Notional Volume		
Natural gas	4,568	5,335	Million MMBtu
Electricity	796,982	800,001	GWh
Financial transmission rights / Congestion revenue rights	248,742	250,895	GWh
Coal	27	35	Million U.S. tons
Fuel oil	2	3	Million gallons
Emissions	28	24	Million U.S. tons
Renewable energy certificates	31	29	Million certificates
Interest rate swaps – variable/fixed	$ 5,300	$ 5,225	Million U.S. dollars
Interest rate swaps - fixed/variable	$ 700	$ 1,300	Million U.S. dollars

Credit Risk-Related Contingent Features of Derivatives

Our derivative contracts may contain certain credit risk-related contingent features that could trigger liquidity requirements in the form of cash collateral, letters of credit or some other form of credit enhancement. Certain of these agreements may require the posting of additional collateral if our credit rating is downgraded by one or more credit rating agencies or include cross-default contractual provisions that could result in the settlement of such contracts if there was a failure under other financing arrangements related to payment terms or other covenants.

The following table presents the commodity derivative liabilities subject to credit risk-related contingent features that are not fully collateralized:

	December 31,	
	2024	2023
	(in millions)	
Fair value of derivative contract liabilities (a)	$ (1,587)	$ (1,890)
Offsetting fair value under netting arrangements (b)	724	692
Cash collateral and letters of credit	471	854
Liquidity exposure	$ (392)	$ (344)

(a) Excludes fair value of contracts that contain contingent features that do not provide specific amounts to be posted if features are triggered, including provisions that generally provide the right to request additional collateral (material adverse change, performance assurance and other clauses).
(b) Amounts include the offsetting fair value of in-the-money derivative contracts and net accounts receivable under master netting arrangements.

Concentrations of Credit Risk Related to Derivatives

We have concentrations of credit risk with the counterparties to our derivative contracts. As of December 31, 2024, total credit risk exposure to all counterparties related to derivative contracts totaled $3.772 billion (including associated accounts receivable). The net exposure to those counterparties totaled $776 million as of December 31, 2024 after taking into effect netting arrangements, setoff provisions and collateral, with the largest net exposure from any single counterparty totaling $262 million. As of December 31, 2024, the credit risk exposure to the banking and financial sector represented 75% of the total credit risk exposure and 26% of the net exposure.

This concentration of credit risk increases the risk that a default by any of our counterparties could have a material effect on our financial condition, results of operations and liquidity. We maintain credit risk policies with regard to our counterparties to minimize overall credit risk. These policies authorize specific risk mitigation procedures including, but not limited to, (i) requiring counterparties to have investment grade credit ratings, (ii) use of standardized master agreements with our counterparties that allow for netting of positive and negative exposures, and (iii) that detail credit enhancements (such as parent guarantees, letters of credit, surety bonds, liens on assets and margin deposits) are required in the event of a material downgrade in their credit rating.

12. FAIR VALUE MEASUREMENTS

Fair value measurements are based upon inputs that market participants use in pricing an asset or liability, which are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect our own market assumptions. We categorize our assets and liabilities recorded at fair value based upon the following fair value hierarchy as defined by GAAP:

- Level 1 valuations use quoted prices in active markets for identical assets or liabilities that are accessible at the measurement date.

- Level 2 valuations use over-the-counter broker quotes, quoted prices for similar assets or liabilities that are corroborated by correlations or other mathematical means, and other valuation inputs such as interest rates and yield curves observable at commonly quoted intervals.

- Level 3 valuations use unobservable inputs for the asset or liability, typically reflecting our estimate of assumptions that market participants would use in pricing the asset or liability. The fair value is therefore determined using model-based techniques, including discounted cash flow models.

The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Assets and liabilities measured at fair value on a recurring basis consisted of the following at the respective balance sheet dates shown below:

	December 31, 2024					December 31, 2023				
	Level 1	Level 2	Level 3 (a)	Reclass (a)	Total	Level 1	Level 2	Level 3 (a)	Reclass (a)	Total
	(in millions)									
Assets:										
Commodity contracts (b)	$ 1,923	$ 462	$ 841	$ 5	$ 3,231	$ 2,886	$ 628	$ 630	$ 14	$ 4,158
Interest rate swaps (b)	—	96	—	—	96	—	64	—	—	64
NDTs – equity securities (c)(d)	1,560	—	—	—	1,560	638	—	—	—	638
NDTs – debt securities (c)(e)	83	1,976	—	—	2,059	—	734	—	—	734
Sub-total	$ 3,566	$ 2,534	$ 841	$ 5	6,946	$ 3,524	$ 1,426	$ 630	$ 14	5,594
Assets measured at net asset value (f):										
NDTs – equity securities (c)(d)(f)					821					579
Total assets					$ 7,767					$ 6,173
Liabilities:										
Commodity contracts (b)	$ 2,118	$ 975	$ 1,593	$ 5	$ 4,691	$ 3,815	$ 1,395	$ 1,674	$ 14	$ 6,898
Interest rate swaps (b)	—	27	—	—	27	—	48	—	—	48
Total liabilities	$ 2,118	$ 1,002	$ 1,593	$ 5	$ 4,718	$ 3,815	$ 1,443	$ 1,674	$ 14	$ 6,946

(a) Fair values for each level are determined on a contract basis, but certain contracts are in both an asset and a liability position. This reclassification represents the adjustment needed to reconcile to the gross amounts presented in the consolidated balance sheets.
(b) See Note 11 for additional information.
(c) NDT assets represent securities held for the purpose of funding the future retirement and decommissioning of our nuclear generation facilities. These investments include equity, debt and other fixed-income securities consistent with investment rules established by the NRC and the PUCT. The NDT investments are included in Investments in the consolidated balance sheets. There were no significant concentrations of credit risk from an individual counterparty or groups of counterparties in our NDT portfolio as of December 31, 2024.
(d) The investment objective for NDT equity securities is to invest tax efficiently and to match the performance of the S&P 500 Index for U.S. equity investments and the MSCI EAFE Index for non-U.S. equity investments.
(e) The investment objective for NDT debt securities is to invest in a diversified, high quality, tax efficient portfolio. The debt securities are weighted with government and investment grade corporate bonds. Other investable debt securities include, but are not limited to, municipal bonds, high yield bonds, securitized bonds, non-U.S. developed bonds, emerging market bonds, loans and treasury inflation-protected securities. The debt securities had an average coupon rate of 3.99% and 3.19% as of December 31, 2024 and 2023, respectively, and an average maturity of 7 years and 11 years as of December 31, 2024 and 2023, respectively. NDT debt securities held as of December 31, 2024 mature as follows: $1.045 billion in one to five years, $599 million in five to 10 years and $415 million after 10 years.

(f) Net asset value is a practical expedient used for the classification of assets that do not have readily determinable fair values and therefore are not classified in the fair value hierarchy. This amount is presented to permit reconciliation of this table to the amounts presented in the consolidated balance sheets.

The following tables present the fair value of the Level 3 assets and liabilities by major contract type and the significant unobservable inputs used in the valuations as of December 31, 2024 and 2023:

December 31, 2024

	Fair Value						
Contract Type (a)	**Assets**	**Liabilities**	**Total, Net**	**Valuation Technique**	**Significant Unobservable Input**	**Range (b)**	**Average (b)**
		(in millions)					
Electricity purchases and sales	$ 606	$ (1,399)	$ (793)	Income Approach	Hourly price curve shape (c)	$ — to $ 95 MWh	$ 48
					Illiquid delivery periods for hub power prices (d)	$ 25 to $140 MWh	$ 83
					Market Heat Rates (d)	$ 30 to $150 MWh	$ 90
Options	6	(139)	(133)	Option Pricing Model	Natural gas to power correlation (e)	10 % to 100 %	55 %
					Power and natural gas volatility (e)	5 % to 710 %	358 %
Financial transmission rights/ Congestion revenue rights	190	(25)	165	Market Approach (f)	Illiquid price differences between settlement points (g)	$(35) to $ 20 MWh	$ (8)
Natural gas	29	(30)	(1)	Income Approach	Natural gas basis (h)	$ — to $ 10 MMBtu	$ 5
					Illiquid delivery periods (i)	$ — to $ 5 MMBtu	$ 2
Other (j)	10	—	10				
Total	$ 841	$ (1,593)	$ (752)				

	December 31, 2023						
	Fair Value						
Contract Type (a)	**Assets**	**Liabilities**	**Total, Net**	**Valuation Technique**	**Significant Unobservable Input**	**Range (b)**	**Average (b)**
		(in millions)					
Electricity purchases and sales	$ 449	$ (1,273)	$ (824)	Income Approach	Hourly price curve shape (c)	$ — to $ 85 MWh	$ 44
					Illiquid delivery periods for hub power prices and Heat Rates (d)	$ 30 to $110 MWh	$ 71
Options	1	(237)	(236)	Option Pricing Model	Natural gas to power correlation (e)	10 % to 100 %	55 %
					Power and natural gas volatility (e)	10 % to 870 %	441 %
Financial transmission rights/ Congestion revenue rights	157	(34)	123	Market Approach (f)	Illiquid price differences between settlement points (g)	$(85) to $ 25 MWh	$ (30)
Natural gas	9	(112)	(103)	Income Approach	Natural gas basis (h)	$ — to $ 15 MMBtu	$ 6
					Illiquid delivery periods (i)	$ — to $ 5 MMBtu	$ 4
Other (j)	14	(18)	(4)				
Total	$ 630	$ (1,674)	$ (1,044)				

(a) Electricity purchase and sales contracts include (i) power and Heat Rate positions in ERCOT, PJM, ISO-NE, NYISO, MISO and CAISO regions, (ii) Options consist of physical electricity options, spread options and natural gas options, (iii) Forward purchase contracts (swaps and options) used to hedge electricity price differences between settlement points are referred to as congestion revenue rights (CRRs) in ERCOT and financial transmission rights (FTRs) in PJM, ISO-NE, NYISO and MISO regions, and (iv) Natural gas contracts include swaps and forward contracts.
(b) The range of the inputs may be influenced by factors such as time of day, delivery period, season and location. The average represents the arithmetic average of the underlying inputs and is not weighted by the related fair value or notional amount.
(c) Primarily based on the historical range of forward average hourly ERCOT North Hub and ERCOT South and West Zone prices.
(d) Primarily based on historical forward ERCOT and PJM power prices and ERCOT Heat Rate variability.
(e) Primarily based on the historical forward correlation and volatility within ERCOT and PJM.
(f) While we use the market approach, there is insufficient market data for the inputs to the valuation to consider the valuation liquid.
(g) Primarily based on the historical price differences between settlement points within ERCOT hubs and load zones.
(h) Primarily based on the historical forward PJM and Northeast natural gas basis prices and fixed prices.
(i) Primarily based on the historical forward natural gas fixed prices.
(j) Other includes contracts for coal and environmental allowances.

The following table presents the changes in fair value of the Level 3 assets and liabilities:

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Net liability balance at beginning of period	$ (1,044)	$ (1,219)	$ (360)
Total unrealized valuation gains (losses)	(175)	(765)	(1,382)
Purchases, issuances and settlements (a):			
Purchases	266	222	185
Issuances	(26)	(30)	(62)
Settlements	137	136	345
Transfers into Level 3 (b)	(15)	(48)	(30)
Transfers out of Level 3 (b)	118	660	85
Net liabilities assumed in connection with the Energy Harbor Merger	(13)	—	—
Net change	292	175	(859)
Net liability balance at end of period	$ (752)	$ (1,044)	$ (1,219)
Unrealized valuation (losses) relating to instruments held at end of period	$ (416)	$ (676)	$ (977)

(a) Settlements reflect reversals of unrealized mark-to-market valuations previously recognized in net income. Purchases and issuances reflect option premiums paid or received, including CRRs and FTRs.

(b) Includes transfers due to changes in the observability of significant inputs. All Level 3 transfers during the periods presented are in and out of Level 2. For the year ended December 31, 2024, transfers into Level 3 primarily consist of power derivatives where forward pricing inputs have become unobservable and transfers out of Level 3 primarily consist of power and natural gas derivatives where forward pricing inputs have become observable. For the year ended December 31, 2023, transfers into Level 3 primarily consist of power derivatives where forward pricing inputs have become unobservable and transfers out of Level 3 primarily consist of power and coal derivatives where forward pricing inputs have become observable. For the year ended December 31, 2022, transfers into Level 3 primarily consist of power and coal derivatives where forward pricing inputs have become unobservable and transfers out of Level 3 primarily consist of power, natural gas, and coal derivatives where forward pricing inputs have become observable.

Assets and Liabilities Recorded on a Non-Recurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis. These assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances. These assets and liabilities can include inventories, assets acquired and liabilities assumed in business combinations, goodwill and other long-lived assets that are written down to fair value when they are determined to be impaired or held for sale.

The Energy Harbor Merger was accounted for under the acquisition method which requires all assets acquired and liabilities assumed in the acquisition be recorded at fair value at the acquisition date. See Note 2 for additional information.

Fair Value of Debt

		December 31, 2024		December 31, 2023	
Instrument	Fair Value Hierarchy	Carrying Amount	Fair Value	Carrying Amount	Fair Value
			(in millions)		
Long-term debt under the Vistra Operations Credit Facilities	Level 2	$ 2,435	$ 2,478	$ 2,456	$ 2,500
BCOP Credit Facilities Tax Credit Bridge Loan	Level 3	344	367	—	—
Vistra Zero Term Loan B Facility	Level 2	685	697	—	—
Vistra Operations Senior Notes	Level 2	12,366	12,428	11,881	11,752
Energy Harbor Revenue Bonds	Level 2	414	431	—	—
Equipment Financing Agreements	Level 3	54	53	65	62
Forward Repurchase Obligation	Level 3	1,335	1,335	—	—

We determine fair value in accordance with accounting standards. We obtain security pricing from an independent party who uses broker quotes and third-party pricing services to determine fair values. Where relevant, these prices are validated through subscription services, such as Bloomberg.

13. ASSET RETIREMENT OBLIGATIONS

Our asset retirement obligations (ARO) primarily relate to nuclear generation plant decommissioning, land reclamation related to lignite mining, remediation or closure of coal ash basins, and generation plant disposal costs. AROs are based on legal obligations associated with enacted law, regulatory, or contractual retirement requirements for which decommissioning timing and cost estimates are reasonably estimable.

The following table summarizes the changes to our current and noncurrent ARO liabilities for the years ended December 31, 2024 and 2023:

	Nuclear Plant Decommissioning	Land Reclamation, Coal Ash and Other	Total
		(in millions)	
Liability at December 31, 2022	$ 1,688	$ 749	$ 2,437
Additions:			
Accretion (a)	54	34	88
Adjustment for change in estimates (b)	—	94	94
Reductions:			
Payments	—	(81)	(81)
Liability at December 31, 2023	1,742	796	2,538
Additions:			
Accretion (a)	130	40	170
Adjustment for change in estimates (b)	—	90	90
Adjustment for obligations assumed through acquisitions	1,368	—	1,368
Reductions:			
Payments	—	(88)	(88)
Liability at December 31, 2024	3,240	838	4,078
Less amounts due currently	—	(142)	(142)
Noncurrent liability at December 31, 2024	$ 3,240	$ 696	$ 3,936

(a) For the year ended December 31, 2024, nuclear plant decommissioning accretion includes $74 million of accretion expense recognized in operating costs in the consolidated statements of operations and $56 million reflected as a change in regulatory liability in the consolidated balance sheets. For the year ended December 31, 2023, nuclear plant decommissioning accretion reflected as a change in regulatory liability in the consolidated balance sheets.

(b) Includes non-cash additions to asset retirement costs included in property, plant, and equipment of $52 million and $67 million for the years ended December 31, 2024 and 2023, respectively.

For the next five years, Vistra is projected to spend approximately $546 million (on a nominal basis) to achieve its mining reclamation and other coal ash remediation objectives.

Nuclear Decommissioning AROs

AROs for nuclear generation decommissioning relate to the Comanche Peak plant in ERCOT and the facilities acquired from Energy Harbor which include the Beaver Valley, Perry and Davis-Besse plants in PJM (the PJM nuclear facilities). To estimate our nuclear decommissioning obligations we use a discounted cash flow model which, on a unit-by-unit basis, considers multiple decommissioning methods and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models, and discount rates.

As of December 31, 2024, the carrying value of our ARO related to our Comanche Peak nuclear generation facility decommissioning totaled $1.797 billion, which is lower than the fair value of the assets contained in the Comanche Peak NDT of $2.249 billion. The difference between the carrying value of the ARO and the NDT represents a regulatory liability of $452 million recorded to the consolidated balance sheets in other noncurrent liabilities and deferred credits since any excess funds in the NDT after decommissioning our Comanche Peak plant would be refunded to Oncor.

The carrying value of our ARO for our PJM nuclear facilities was recorded at fair value on the Merger Date. ARO accretion expense attributable to the PJM nuclear facilities is reflected in operating costs in the consolidated statements of operations. ARO estimates for the PJM nuclear facilities will be evaluated on an individual unit basis at least every five years unless triggering events warrant a more frequent review. Any changes in ARO estimates are recorded as an increase or decrease in ARO liability along with a corresponding change to asset retirement cost asset within property, plant, and equipment in the consolidated balance sheets; however, if the ARO estimate decreases by more than the remaining ARO asset, the balance of the change is recorded as a reduction to operating costs in the consolidated statement of operations.

14. PENSION AND OTHER POSTRETIREMENT EMPLOYEE BENEFITS (OPEB) PLANS

Vistra is the plan sponsor of the Vistra Retirement Plan (the Retirement Plan), which provides benefits to eligible employees of its subsidiaries. Oncor is a participant in the Retirement Plan. Effective January 1, 2018, Vistra entered into a contractual arrangement with Oncor whereby the costs associated with providing OPEB coverage for certain retirees (Split Participants) whose employment included service with both the regulated businesses of Oncor (or its predecessors) and the non-regulated businesses of Vistra (or its predecessors) are split between Oncor and Vistra. As Vistra accounts for its interests in the Retirement Plan as a multiple employer plan, only Vistra's share of the plan assets and obligations are reported in the pension benefit information presented below. The Retirement Plan is a qualified defined benefit pension plan under Section 401(a) of the Internal Revenue Code of 1986, as amended (Code), and is subject to the provisions of ERISA. The Retirement Plan provides benefits to participants under one of two formulas: (i) a Cash Balance Formula under which participants earn monthly contribution credits based on their compensation and a combination of their age and years of service, plus monthly interest credits or (ii) a Traditional Retirement Plan Formula based on years of service and the average earnings of the three years of highest earnings. Under the Cash Balance Formula, future increases in earnings will not apply to prior service costs. It is our policy to fund the Retirement Plan assets only to the extent required under existing federal regulations. Since 2012, the Retirement Plan has been closed to new participants and the only participants who remain in the Retirement Plan are employees who were active prior to 2012, including retired collective bargaining unit employees. Accordingly, ongoing expenses associated with the Retirement plan are immaterial, including expenses associated with pensions plans acquired from Dynegy and Energy Harbor.

Vistra and our participating subsidiaries offer other postretirement employee benefits (OPEB) in the form of certain health care and life insurance benefits to eligible retirees and their eligible dependents. The retiree contributions required for such coverage vary based on a formula depending on the retiree's age and years of service.

Pension and OPEB Costs

The following table summarizes the total benefit costs of our pension and OPEB plans for the years ended December 31, 2024, 2023, and 2022. The individual components of benefit costs, including service cost, interest cost, expected return on assets and the net amortization of unrecognized amounts from accumulated other comprehensive income were immaterial.

	Year Ended December 31,		
	2024	2023	2022
	(in millions)		
Pension costs	$ 9	$ 9	$ 2
OPEB costs	5	5	4
Total benefit costs recognized as expense	$ 14	$ 14	$ 6

Market-Related Value of Assets Held in Pension Benefit Trusts

We use the calculated value method to determine the market-related value of the assets held in the trust for purposes of calculating pension costs. We include all gains or losses in the market-related value of assets over a rolling four-year period. Each year, 25% of such gains and losses for the current year and for each of the preceding three years is included in the market-related value. Each year, the market-related value of assets is increased for contributions to the plan and investment income and is decreased for benefit payments and expenses for that year.

Detailed Information Regarding Pension Plans and OPEB Benefits

The following information is based on a December 31, 2024, 2023, and 2022 measurement dates:

	Retirement Plan			OPEB Plans		
	Year Ended December 31,			Year Ended December 31,		
	2024	2023	2022	2024	2023	2022
Assumptions Used to Determine Benefit Obligations at Period End:						
Discount rate	5.63 %	4.97 %	5.16 %	5.62 %	4.98 %	5.18 %
Expected rate of compensation increase (Vistra Plan)	3.50 %	3.64 %	3.79 %			
Expected rate of compensation increase (Dynegy Plan)	4.46 %					
Interest crediting rate for cash balance plans	3.75 %	3.50 %	3.00 %			

	Retirement Plan		OPEB Plans	
	Year Ended December 31,		Year Ended December 31,	
	2024	2023	2024	2023
	(in millions, except percentages)			
Change in Pension and Postretirement Benefit Obligations:				
Projected benefit obligation at beginning of period	$ 425	$ 449	$ 108	$ 110
Acquisitions	23	—	—	—
Service cost	2	3	1	1
Interest cost	21	21	5	5
Participant contributions	—	—	3	3
Plan amendments	—	1	—	—
Actuarial (gain) loss	(24)	10	(7)	1
Benefits paid	(38)	(59)	(11)	(12)
Projected benefit obligation at end of year	$ 409	$ 425	$ 99	$ 108
Accumulated benefit obligation at end of year	$ 408	$ 422	$ —	$ —
Change in Plan Assets:				
Fair value of assets at beginning of period	$ 285	$ 320	$ 12	$ 29
Acquisitions	18	—	—	—
Employer contributions	19	—	8	9
Participant contributions	—	—	2	3
Actual gain on assets	1	24	1	2
Transfers	—	—	(2)	(19)
Benefits paid	(38)	(59)	(11)	(12)
Fair value of assets at end of year	$ 285	$ 285	$ 10	$ 12
Funded Status:				
Projected benefit obligation	$ (409)	$ (425)	$ (99)	$ (108)
Fair value of assets	285	285	10	12
Funded status at end of year	$ (124)	$ (140)	$ (89)	$ (96)

	Retirement Plan		OPEB Plans	
	Year Ended December 31,		Year Ended December 31,	
	2024	2023	2024	2023
Amounts Recognized in the Balance Sheet Consist of:				
Investments	$ 1	$ —	$ 2	$ 3
Other current liabilities	—	—	(8)	(9)
Other noncurrent liabilities	(125)	(140)	(83)	(90)
Net liability recognized	$ (124)	$ (140)	$ (89)	$ (96)
Amounts Recognized in Accumulated Other Comprehensive Income Consist of:				
Net actuarial (gain) loss	$ (5)	$ 4	$ (22)	$ (15)
Prior services cost	—	3	1	1
Net actuarial (gain) loss and prior service cost	$ (5)	$ 7	$ (21)	$ (14)

Fair Value Measurement of Pension and OPEB Plan Assets

Retirement Plan

As of December 31, 2024 and 2023, all of the Retirement Plan assets were measured at fair value using the net asset value per share (or its equivalent) except as noted and consisted of the following:

	December 31,	
	2024	2023
	(in millions)	
Asset Category:		
Cash commingled trusts	$ 6	$ 4
Equity securities:		
Global equities	86	82
Fixed income securities:		
Corporate bonds (a)	79	82
Government bonds	42	54
Other (b)	28	18
Real estate	27	28
Hedge funds	17	17
Total assets measured at net asset value	$ 285	$ 285

(a) Substantially all corporate bonds are rated investment grade by a major ratings agency such as Moody's.
(b) Consists primarily of high-yield bonds, emerging market debt, bank loans, securitized bonds and private investment grade fixed income.

OPEB Plans

As of December 31, 2024 and 2023, the Vistra OPEB plan assets measured at fair value totaled $10 million and $12 million, respectively. At December 31, 2024 and 2023, assets consisted of $7 million and $9 million, respectively, of comingled funds valued at net asset value and $3 million and $3 million, respectively, of municipal bond and cash equivalent mutual funds classified as Level 1.

Pension Plans with Projected Benefit Obligations (PBO) and Accumulated Benefit Obligations (ABO) in Excess of Plan Assets

The following table provides information regarding pension plans with PBO and ABO in excess of the fair value of plan assets.

	December 31,	
	2024	2023
	(in millions)	
Pension Plans with PBO and ABO in Excess of Plan Assets:		
Projected benefit obligations	$ 409	$ 425
Accumulated benefit obligation	$ 408	$ 422
Plan assets	$ 285	$ 285

Retirement Plan Investment Strategy and Asset Allocations

Our investment objective for the Retirement Plan is to invest in a suitable mix of assets to meet the future benefit obligations at an acceptable level of risk, while minimizing the volatility of contributions. Fixed income securities held primarily consist of corporate bonds from a diversified range of companies, U.S. Treasuries and agency securities, and money market instruments. Equity securities are held to enhance returns by participating in a wide range of investment opportunities. International equity securities are used to further diversify the equity portfolio and may include investments in both developed and emerging markets. Real estate, hedge funds, and credit strategies (primarily high yield bonds and emerging market debt) provide additional portfolio diversification and return potential.

The target asset allocation ranges of pension plan investments by asset category are as follows:

	Retirement Plan		
	Target Allocation Ranges		
Asset Category:	Vistra Plan	Dynegy Plan	Energy Harbor Plan
Fixed income securities	50 % - 70%	40 % - 50%	45 % - 55%
Global equity securities	20 % - 28%	28 % - 38%	30 % - 38%
Real estate	6 % - 10%	7 % - 15%	5 % - 10%
Credit strategies	2 % - 6%	4 % - 8%	4 % - 8%
Hedge funds	2 % - 6%	4 % - 8%	1 % - 5%

Retirement Plan Expected Long-Term Rate of Return on Assets Assumption

The Retirement Plan strategic asset allocation is determined in conjunction with the plan's advisors and utilizes a comprehensive Asset-Liability modeling approach to evaluate potential long-term outcomes of various investment strategies. The study incorporates long-term rate of return assumptions for each asset class based on historical and future expected asset class returns, current market conditions, rate of inflation, current prospects for economic growth, and taking into account the diversification benefits of investing in multiple asset classes and potential benefits of employing active investment management.

	Retirement Plan		
	Expected Long-Term Rate of Return		
Asset Class:	Vistra Plan	Dynegy Plan	Energy Harbor Plan
Fixed income securities	5.9 %	5.5 %	4.6 %
Global equity securities	7.2 %	7.2 %	7.2 %
Real estate	5.8 %	5.8 %	5.8 %
Credit strategies	7.4 %	7.4 %	7.4 %
Hedge funds	7.3 %	7.3 %	7.3 %
Weighted average	6.3 %	6.3 %	5.8 %

Benefit Plan Assumed Health Care Cost Trend Rates

The following tables provide information regarding the assumed health care cost trend rates.

	December 31,	
	2024	2023
Assumed Health Care Cost Trend Rates-Not Medicare Eligible:		
Health care cost trend rate assumed for next year	7.00 %	7.00 %
Rate to which the cost trend is expected to decline (the ultimate trend rate)	4.50 %	4.50 %
Year that the rate reaches the ultimate trend rate	2034	2033
Assumed Health Care Cost Trend Rates-Medicare Eligible:		
Health care cost trend rate assumed for next year (Vistra Plan)	15.70 %	12.90 %
Health care cost trend rate assumed for next year (Split-Participant Plan)	13.80 %	12.30 %
Rate to which the cost trend is expected to decline (the ultimate trend rate)	4.50 %	4.50 %
Year that the rate reaches the ultimate trend rate	2034	2033

Significant Concentrations of Risk

The plans' investments are exposed to risks such as interest rate, capital market and credit risks. We seek to optimize return on investment consistent with levels of liquidity and investment risk which are prudent and reasonable, given prevailing capital market conditions and other factors specific to us. While we recognize the importance of return, investments will be diversified in order to minimize the risk of large losses unless, under the circumstances, it is clearly prudent not to do so. There are also various restrictions and guidelines in place including limitations on types of investments allowed and portfolio weightings for certain investment securities to assist in the mitigation of the risk of large losses.

Assumed Discount Rate

We selected the assumed discount rates using the Aon AA Above Median yield curve, which is based on corporate bond yields and at December 31, 2024 consisted of 490 corporate bonds with an average rating of AA using Moody's, S&P and Fitch ratings.

Contributions

Contributions to the Retirement Plan for the years ended December 31, 2024, 2023, and 2022 totaled $19 million, zero, and zero, respectively, and contributions in 2025 are expected to total $25 million. OPEB plan funding for each of the years ended December 31, 2024, 2023, and 2022 totaled $8 million, $9 million, and $9 million, respectively, and funding in 2025 is expected to total $8 million.

Future Benefit Payments

Estimated future benefit payments to beneficiaries are as follows:

	2025	2026	2027	2028	2029	2030-2034
			(in millions)			
Pension benefits	$ 33	$ 34	$ 43	$ 32	$ 32	$ 151
OPEB	$ 9	$ 9	$ 9	$ 8	$ 8	$ 36

Qualified Savings Plans

Our employees may participate in a qualified savings plan (the Thrift Plan). This plan is a participant-directed defined contribution plan intended to qualify under Section 401(a) of the Code and is subject to the provisions of ERISA. Under the terms of the Thrift Plan, employees who do not earn more than the IRS threshold compensation limit used to determine highly compensated employees may contribute, through pre-tax salary deferrals and/or after-tax payroll deductions, the lesser of 75% of their regular salary or wages or the maximum amount permitted under applicable law. Employees who earn more than such threshold may contribute from 1% to 20% of their regular salary or wages. Employer matching contributions are also made in an amount equal to 100% (75% for employees covered under the traditional formula in the Retirement Plan) of the first 6% of employee contributions. Employer matching contributions are made in cash and may be allocated by participants to any of the plan's investment options.

Aggregate employer contributions to the qualified savings plans totaled $46 million, $33 million, and $33 million for the years ended December 31, 2024, 2023, and 2022, respectively.

15. COMMITMENTS AND CONTINGENCIES

Contractual Commitments

As of December 31, 2024, we had minimum contractual commitments under long-term service and maintenance contracts, energy-related contracts and other agreements as follows:

	Long-Term Service and Maintenance Contracts (a)	Coal transportation agreements	Pipeline transportation and storage reservation fees	Water Contracts
	(in millions)			
2025	$ 227	$ 59	$ 187	$ 9
2026	206	26	200	9
2027	207	26	209	9
2028	265	—	228	9
2029	259	—	234	9
Thereafter	1,916	—	115	37
Total	$ 3,080	$ 111	$ 1,173	$ 82

(a) Long-term service and maintenance contracts reflect expected expenditures as these contracts do not include minimum spending requirements, but can only be terminated based on events outside the control of the Company.

In addition to the commitments detailed above, we have nuclear fuel contracts with early termination penalties. As of December 31, 2024, termination costs of $116 million would be incurred if we terminated those contracts.

Expenditures under our coal purchase and coal transportation agreements totaled $744 million, $936 million, and $995 million for the years ended December 31, 2024, 2023, and 2022, respectively.

Guarantees

We have entered into contracts that contain guarantees to unaffiliated parties that could require performance or payment under certain conditions.

Letters of Credit

As of December 31, 2024, we had outstanding letters of credit totaling $2.935 billion as follows:

- $2.560 billion to support commodity risk management and collateral requirements in the normal course of business, including over-the-counter and exchange-traded transactions and collateral postings with ISOs/RTOs;
- $248 million to support battery and solar development projects;
- $25 million to support executory contracts and insurance agreements;
- $86 million to support our REP financial requirements with the PUCT; and
- $16 million for other credit support requirements.

Surety Bonds

As of December 31, 2024, we had outstanding surety bonds totaling $1.087 billion to support performance under various contracts and legal obligations in the normal course of business.

Litigation and Regulatory Proceedings

Our material legal proceedings and regulatory proceedings affecting our business are described below. We believe that we have valid defenses to the legal proceedings described below and intend to defend them vigorously. We also intend to participate in the regulatory processes described below. We record reserves for estimated losses related to these matters when information available indicates that a loss is probable and the amount of the loss, or range of loss, can be reasonably estimated. As applicable, we have established an adequate reserve for the matters discussed below. In addition, legal costs are expensed as incurred. Management has assessed each of the following legal matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought, and the probability of success. Unless specified below, we are unable to predict the outcome of these matters or reasonably estimate the scope or amount of any associated costs and potential liabilities, but they could have a material impact on our results of operations, liquidity, or financial condition. As additional information becomes available, we adjust our assessment and estimates of such contingencies accordingly. Because litigation and rulemaking proceedings are subject to inherent uncertainties and unfavorable rulings or developments, it is possible that the ultimate resolution of these matters could be at amounts that are different from our currently recorded reserves and that such differences could be material.

Litigation

Natural Gas Index Pricing Litigation — We, through our subsidiaries, and another company remain named as defendants in one consolidated putative class action lawsuit pending in federal court in Wisconsin claiming damages resulting from alleged price manipulation through false reporting of natural gas prices to various index publications, wash trading, and churn trading from 2000-2002. The plaintiffs in these cases allege that the defendants engaged in an antitrust conspiracy to inflate natural gas prices during the relevant time period and seek damages under the respective state antitrust statutes. In April 2023, the U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit Court) heard oral argument on an interlocutory appeal challenging the district court's order certifying a class.

Illinois Attorney General Complaint Against Illinois Gas & Electric (IG&E) — In May 2022, the Illinois Attorney General filed a complaint against IG&E, a subsidiary we acquired when we purchased Crius in July 2019. The complaint filed in Illinois state court alleges, among other things, that IG&E engaged in improper marketing conduct and overcharged customers. The vast majority of the conduct in question occurred prior to our acquisition of IG&E. In July 2022, we moved to dismiss the complaint, and in October 2022, the district court granted in part our motion to dismiss, barring all claims asserted by the Illinois Attorney General that were outside of the 5-year statute of limitations period, which now limits the period during which claims may be made to start in May 2017 rather than extending back to 2013 as the Illinois Attorney General had alleged in its complaint.

Ohio House Bill 6 ("HB6") — In July 2019, Ohio adopted a law referred to as HB6, which, among other things, provided subsidies for two nuclear power plants which we acquired in March 2024 upon the closing of our merger with Energy Harbor. We had opposed enactment of that subsidy legislation at the time, and the nuclear subsidies were repealed in 2021 prior to any subsidies being distributed. The U.S. Attorney's Office conducted an investigation into the activities related to the passage of HB6, and Energy Harbor received a grand jury subpoena in July 2020 requiring production of certain information related to that investigation. Energy Harbor completed its responses to that subpoena by December 2021. In August 2020, the Ohio Attorney General filed a civil Racketeer Influenced and Corrupt Organizations Act (RICO) complaint against FirstEnergy Corp. and various Energy Harbor companies related to passage of HB6 (*State of Ohio ex rel. Dave Yost, Ohio Attorney General v. FirstEnergy Corp., et al.*, Franklin County, Ohio Common Pleas Court Case No. 20CV006281 and *State of Ohio ex rel. Dave Yost, Ohio Attorney General v. Energy Harbor Corp.*, et al., Franklin County, Ohio Common Pleas Court Case No. 20CV007386). Motions to dismiss those cases remain pending and the case is currently stayed.

Winter Storm Uri Legal Proceedings

Regulatory Investigations and Other Litigation Matters — Following the events of Winter Storm Uri, various regulatory bodies, including ERCOT, the ERCOT Independent Market Monitor, and the Texas Attorney General initiated investigations or issued requests for information of various parties related to the significant load shed event that occurred during the event as well as operational challenges for generators arising from the event, including performance and fuel and supply issues. We responded to all those investigatory requests. In addition, a large number of personal injury and wrongful death lawsuits related to Winter Storm Uri have been, and continue to be, filed in various Texas state courts against us and numerous generators, transmission and distribution utilities, retail and electric providers, as well as ERCOT. We and other defendants requested that all pretrial proceedings in these personal injury cases be consolidated and transferred to a single multi-district litigation (MDL) pretrial judge. In June 2021, the MDL panel granted the request to consolidate all these cases into an MDL for pretrial proceedings. Additional personal injury cases that have been, and continue to be, filed on behalf of additional plaintiffs have been consolidated with the MDL proceedings. In addition, in January 2022, an insurance subrogation lawsuit was filed in Austin state court by over one hundred insurance companies against ERCOT, Vistra and several other defendants. The lawsuit seeks recovery of insurance funds paid out by these insurance companies to various policyholders for claims related to Winter Storm Uri, and that case has also now been consolidated with the MDL proceedings. In the summer of 2022, various defendant groups filed motions to dismiss five so-called bellwether cases, and the MDL court heard oral argument on those motions in October 2022. In January 2023, the MDL court ruled on the various motions to dismiss and denied the motions to dismiss of the generator defendants and the transmission distribution utilities defendants, but granted the motions of some of the other defendant groups, including the retail electric providers and ERCOT. In February 2023, the generator defendants filed a mandamus petition with the First Court of Appeals in Houston, Texas (First Court of Appeals) to review the MDL court's denial of the motion to dismiss. In December 2023, the First Court of Appeals in a unanimous decision granted our mandamus petition and instructed the MDL court to grant the motions to dismiss in full filed by the generator defendants. In January 2024, the plaintiffs filed a request with the full Court of Appeals to review that panel ruling, which was denied in November 2024. The plaintiffs have petitioned the Texas Supreme Court to review that decision. We believe we have strong defenses to these lawsuits and intend to defend against these cases vigorously if they continue.

Moss Landing 300 Battery Fire

On January 16, 2025, we detected a fire at our Moss Landing 300 MW energy storage facility at the Moss Landing Power Plant site. We are working closely with all local, state, and federal regulatory authorities on the response, and we are investigating the cause of the fire. We are also responding to various regulatory bodies, including the CPUC, the EPA, and others investigating the incident. Finally, two lawsuits have been filed in California state court against Vistra, LG, and others, arising from the event.

Unleashing American Energy Executive Order

In January 2025, President Trump issued a series of executive orders, including an order titled Unleashing American Energy (the Order) that ordered that all federal agencies are to review all existing regulations, orders, and other actions for consistency with the policy goals, and develop an action plan within 30 days to resolve any policy inconsistencies. The Order requires the EPA to review the GHG, CSAPR, Legacy CCR and ELG rules discussed below. Additionally, the Order states the U.S. Attorney General may request a stay of the litigation involving these rules while the EPA conducts its reviews.

Greenhouse Gas Emissions (GHG)

In May 2023, the EPA released a proposal regulating power plant GHG emissions, while also proposing to repeal the Affordable Clean Energy (ACE) rule that had been finalized by the EPA in July 2019. In May 2024, the EPA published a final GHG rule that repealed the ACE rule and sets limits for (a) new natural gas-fired combustion turbines and (b) existing coal-, oil- and natural gas-fired steam generation units. The standards are based on technologies such as carbon capture and sequestration/storage (CCS) and natural gas co-firing. Starting in 2030, the rule would begin to require more CO_2 emissions control at certain existing fossil fuel-fired steam generating units, with more stringent standards beginning in 2032 for coal-fired units that plan to operate for a longer period of time. For new natural gas combustion turbines that operate more frequently, the rule would phase in increasingly stringent CO_2 requirements over time. Under the rule, states would be required to submit plans to the EPA within 24 months of the rule's publication in the Federal Register that provide for the establishment, implementation, and enforcement of standards of performance for existing sources. These state plans must generally establish standards that are at least as stringent as the EPA's emission guidelines. Under the rule, existing coal-fired steam generation units that will operate on or after January 1, 2039 must start complying with their standards of performance (based on application of CCS with 90 percent capture) by January 1, 2032. Units that are permanently retiring before January 1, 2039, but after December 31, 2031, must start complying with their standards of performance (based on co-firing with 40 percent natural gas on a heat input basis) beginning on January 1, 2030. Units permanently retiring by January 1, 2032 are exempt from the rule. Given our previously announced coal unit retirement commitments, our Martin Lake and Oak Grove plants are the only coal units that are subject to this rule. Our Graham, Lake Hubbard, Stryker Creek and Trinidad oil/natural gas facilities are also regulated under this rule. None of our existing large or small combustion turbines are subject to this rule. The rule also regulates any new gas units. For new combustion turbine units, the rule establishes three different categories depending on how intensively those units are operated, with immediate compliance obligations for all three categories but more stringent standards beginning in 2032 only for the category of units operating the most intensively. Following finalization of the rule in May 2024, 17 petitions for review from various states, industry groups, and companies were filed in the D.C. Circuit Court along with multiple motions to stay the rule. We are participating in an industry coalition challenging the rule. In July 2024, the D.C. Circuit Court denied the motions to stay and a number of parties subsequently filed an emergency request with the U.S. Supreme Court to stay the rule which was denied in October 2024. Oral argument on the merits of the legal challenges to the rule was held in December 2024 before the D.C. Circuit Court. In February 2025, the D.C. Circuit granted the unopposed motion filed by the Department of Justice on behalf of the EPA, holding the litigation in abeyance for a period of 60 days while the new leadership at the EPA evaluates the rule and determines how it wishes to proceed.

Cross-State Air Pollution Rule (CSAPR) and Good Neighbor Plan

In October 2015, the EPA revised the primary and secondary ozone National Ambient Air Quality Standards (NAAQS) to lower the 8-hour standard for ozone emissions during ozone season (May to September). As required under the CAA, in October 2018, the State of Texas submitted a State Implementation Plan (SIP) to the EPA demonstrating that emissions from Texas sources do not contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to the revised ozone NAAQS. In February 2023, the EPA disapproved Texas' SIP and the State of Texas, Luminant, certain trade groups, and others challenged that disapproval in the U.S. Court of Appeals for the Fifth Circuit (Fifth Circuit Court). In March 2023, those same parties filed motions to stay the EPA's SIP disapproval in the Fifth Circuit Court and the EPA moved to transfer our challenges to the D.C. Circuit Court or have those challenges dismissed.

In April 2022, prior to the EPA's disapproval of Texas' SIP, the EPA proposed a Federal Implementation Plan (FIP) to address the 2015 ozone NAAQS. We, along with many other companies, trade groups, states, and ISOs, including ERCOT, PJM and MISO, filed responsive comments to the EPA's proposal in June 2022, expressing concerns about certain elements of the proposal, particularly those that may result in challenges to electric reliability under certain conditions. In March 2023, the EPA administrator signed its final FIP, called the Good Neighbor Plan (GNP). The FIP applied to 22 states beginning with the 2023 ozone seasons. States where Vistra operates generation units that would be subject to this rule are Illinois, New Jersey, New York, Ohio, Pennsylvania, Texas, Virginia, and West Virginia. Texas would be moved into the revised (and more restrictive) Group 3 trading program previously established in the Revised CSAPR Update Rule that includes emission budgets for 2023 that the EPA says are achievable through existing controls installed at power plants. Allowances will be limited under the program and will be further reduced beginning in ozone season 2026 to a level that is intended to reduce operating time of coal-fueled power plants during ozone season or force coal plants to retire, particularly those that do not have selective catalytic reduction systems such as our Martin Lake power plant.

In May 2023, the Fifth Circuit Court granted our motion to stay the EPA's disapproval of Texas' SIP pending a decision on the merits and denied the EPA's motion to transfer our challenge to the D.C. Circuit Court. As a result of the stay, we do not believe the EPA has authority to implement the GNP FIP as to Texas sources pending the resolution of the merits, meaning that Texas will remain in Group 2 and not be subject to any requirements under the GNP FIP at least until the Fifth Circuit Court rules on the merits. Oral argument was heard in December 2023 before the Fifth Circuit Court. In June 2023, the EPA published the final FIP in the Federal Register, which included requirements as to Texas despite the stay of the SIP disapproval by the Fifth Circuit Court. In June 2023, the State of Texas, Luminant and various other parties also filed challenges to the GNP FIP in the Fifth Circuit Court, filed a motion to stay the FIP and confirm venue for this dispute in the Fifth Circuit Court. After the motion to stay and to confirm venue was filed, the EPA signed an interim final rule on June 29, 2023 that confirms the GNP FIP as to Texas is stayed. In February 2025, the Department of Justice filed a motion on behalf of the EPA in the Fifth Circuit Court, seeking to hold the litigation in abeyance while the new leadership at the EPA evaluates the rule and determines how it wishes to proceed. In February 2025, the State of Texas filed a response opposing the requested abatement, which we joined. In July 2023, the Fifth Circuit Court ruled that the GNP FIP challenge would be held in abeyance pending the resolution of the litigation on the SIP disapproval and denied the motion to stay as not needed given the EPA's administrative stay. In a related action brought by other states and parties challenging the GNP FIP, in June 2024, the U.S. Supreme Court granted a stay of the GNP FIP pending a review of the merits by the D.C. Circuit Court and any further appeal to the U.S. Supreme Court. As a result, the GNP FIP is now stayed for all covered states until the courts resolve the legality of the FIP. In February 2025, the D.C. Circuit Court denied a motion filed by the Department of Justice on behalf of the EPA, seeking to hold the litigation in abeyance for a period of 60 days while the new leadership at the EPA evaluates the rule and determines how it wishes to proceed.

Regional Haze — Reasonable Progress and Best Available Retrofit Technology (BART) for Texas

In October 2017, the EPA issued a final rule addressing BART for Texas electricity generation units, with the rule serving as a partial approval of Texas' 2009 SIP and a partial FIP. For SO_2, the rule established an intrastate Texas emission allowance trading program as a "BART alternative" that operates in a similar fashion to a CSAPR trading program. The program includes 39 generation units (including the Martin Lake, Big Brown, Monticello, Sandow 4, Coleto Creek, Stryker 2, and Graham 2 plants). The compliance obligations in the program started on January 1, 2019. For NO_X, the rule adopted the CSAPR's ozone program as BART and for particulate matter, the rule approved Texas' SIP that determines that no electricity generation units are subject to BART for particulate matter. In August 2020, the EPA issued a final rule affirming the prior BART final rule but also included additional revisions that were proposed in November 2019. Challenges to both the 2017 rule and the 2020 rules have been consolidated in the D.C. Circuit Court, where we have intervened in support of the EPA. We are in compliance with the rule, and the retirements of our Monticello, Big Brown, and Sandow 4 plants have enhanced our ability to comply. The EPA is in the process of reconsidering the BART rule, and the challenges in the D.C. Circuit Court have been held in abeyance pending the EPA's final action on reconsideration. In May 2023, a proposed BART rule was published in the Federal Register that would withdraw the trading program provisions of the prior rule and would establish SO_2 limits on six facilities in Texas, including Martin Lake and Coleto Creek. Under the current proposal, compliance would be required within 3 years for Martin Lake and 5 years for Coleto Creek. Due to the announced shutdown for Coleto Creek, we do not anticipate any impacts at that facility, and we are evaluating potential compliance options at Martin Lake should this proposal become final. We submitted comments to the EPA on this proposal in August 2023.

SO_2 Designations for Texas

In November 2016, the EPA finalized its nonattainment designations for counties surrounding our Martin Lake generation plant and our now retired Big Brown and Monticello plants. The final designations require Texas to develop nonattainment plans for these areas. In February 2017, the State of Texas and Luminant filed challenges to the nonattainment designations in the Fifth Circuit Court. In August 2019, the EPA issued a proposed Error Correction Rule for all three areas, which, if finalized, would have revised its previous nonattainment designations and each area at issue would be designated unclassifiable. In May 2021, the EPA finalized a "Clean Data" determination for the areas surrounding the retired Big Brown and Monticello plants, redesignating those areas as attainment based on monitoring data supporting an attainment designation. In June 2021, the EPA published two notices; one that it was withdrawing the August 2019 Error Correction Rule and a second separate notice denying petitions from Luminant and the State of Texas to reconsider the original nonattainment designations. We, along with the State of Texas, challenged that EPA action and have consolidated it with the pending challenge in the Fifth Circuit Court, and this case was argued before the Fifth Circuit Court in July 2022. In September 2021, the TCEQ considered a proposal for its nonattainment SIP revision for the Martin Lake area and an agreed order to reduce SO_2 emissions from the plant. The proposed agreed order associated with the SIP proposal reduced emission limits as of January 2022. Emission reductions required are those necessary to demonstrate attainment with the NAAQS. The TCEQ's SIP action was finalized in February 2022 and has been submitted to the EPA for review and approval. In January 2024, in a split decision, the Fifth Circuit Court denied the petitions for review we and the State of Texas filed over the EPA's 2016 nonattainment designation for SO_2 for the area around Martin Lake. As a result of this decision, the EPA's nonattainment designation – originally made in 2016 – remains in place. In February 2024, we filed a petition asking the full Fifth Circuit Court to review the panel decision issued in January 2024, which remains pending before the full Fifth Circuit Court. In August 2024, the EPA proposed a Finding of Failure to attain the SO_2 standard for Rusk and Panola Counties, a partial approval and partial disapproval of the Texas SIP and a proposed federal plan for the area. In December 2024, the EPA finalized the Finding of Failure to attain the standard and stated that it would take final action of the SIP partial approval and disapproval in a future action. In February 2025, we, along with the State of Texas, filed a challenge to the Finding of Failure in the Fifth Circuit Court.

Particulate Matter

In February 2024, the EPA issued a rule addressing the annual health-based national ambient air quality standards for fine particulate matter (or PM2.5). In general, the rule lowers the level of the annual PM2.5 standard from 12.0 micrograms per cubic meter (µg/m3) to 9.0 µg/m3. The effective date of the rule is 60 days from publication in the Federal Register, and the earliest attainment date for areas exceeding the new standard is 2032. Based on 2021-2023 design value associated with the rule, we have just four plants (Calumet (Illinois), Dicks Creek and Miami Fort (Ohio), and Lake Hubbard (Texas)) operating in areas where the air quality monitoring data are currently exceeding the new PM2.5 standard. We have previously announced that our Miami Fort generation facility will close by the end of 2027. States will have to develop a plan (by late 2027 at the earliest) to get those areas into attainment and there would be a possibility that additional controls would be required for those sites. However, before the state begins this planning process, the designation process will occur within two years from the issuance of the final rule. The states develop recommendations about the boundaries of the nonattainment counties and the EPA must finalize the designations including the boundaries of each nonattainment area.

Effluent Limitation Guidelines (ELGs)

In November 2015, the EPA revised the ELGs for steam electricity generation facilities, which will impose more stringent standards (as individual permits are renewed) for wastewater streams, such as flue gas desulfurization (FGD), fly ash, bottom ash, and flue gas mercury control wastewaters. Various parties filed petitions for review of the ELG rule, and the petitions were consolidated in the Fifth Circuit Court. In April 2017, the EPA granted petitions requesting reconsideration of the ELG rule and administratively stayed the rule's compliance date deadlines. In April 2019, the Fifth Circuit Court vacated and remanded portions of the EPA's ELG rule pertaining to effluent limitations for legacy wastewater and leachate. The EPA published a final rule in October 2020 that extends the compliance date for both FGD and bottom ash transport water to no later than December 2025, as negotiated with the state permitting agency. Additionally, the final rule allows for a retirement exemption that exempts facilities certifying that units will retire by December 2028 provided certain effluent limitations are met. In November 2020, environmental groups petitioned for review of the new ELG revisions, and Vistra subsidiaries filed a motion to intervene in support of the EPA in December 2020. Notifications were made to Texas, Illinois, and Ohio state agencies on the retirement exemption for applicable coal plants by the regulatory deadline of October 13, 2021. In May 2024, the EPA published the final ELG rule revisions, which contain new requirements for legacy wastewater and combustion residual leachate. The final rule also leaves in place the subcategory for facilities that permanently cease coal combustion by 2028. We are reviewing the rule for impact but believe it will require additional treatment costs for legacy wastewaters during pond closure activities and combustion residual leachate. At this time, we don't expect the impact of these additional treatment costs to be material. A number of parties have since challenged the rule and that case is pending in the U.S. Court of Appeals for the Eighth Circuit. We are not a party to that litigation. In February 2025, the Department of Justice on behalf of the EPA filed an unopposed motion seeking to hold the litigation in abeyance while the new leadership at the EPA evaluates the rule and determines how it wishes to proceed.

Coal Combustion Residuals (CCR) Rule Revisions and Extension Applications

In August 2018, the D.C. Circuit Court issued a decision that vacates and remands certain provisions of the 2015 CCR rule, including an applicability exemption for legacy impoundments. In August 2020, the EPA issued a final rule establishing a deadline of April 11, 2021 to cease receipt of waste and initiate closure at unlined CCR impoundments. The 2020 final rule allows a generation plant to seek the EPA's approval to extend this deadline if no alternative disposal capacity is available and either a conversion to comply with the CCR rule is underway or retirement will occur by either 2023 or 2028 (depending on the size of the impoundment at issue).

Prior to the November 2020 deadline to seek extensions, we submitted applications to the EPA requesting compliance extensions under both conversion and retirement scenarios. In January 2022, the EPA determined that our conversion and retirement applications for our CCR facilities were complete but has not yet proposed action on any of those applications.

Legacy CCR Rulemaking

In May 2024, the EPA published a final rule that expands coverage of groundwater monitoring and closure requirements to the following two new categories of units: (a) legacy CCR surface impoundments which are CCR surface impoundments that no longer receive CCR but contained both CCR and liquids on or after October 19, 2015 and (b) "CCR management units" (CCRMUs) which generally could encompass noncontainerized ash deposits greater than one ton and impoundments and landfills that closed prior to October 19, 2015. As part of the rule, the EPA identified numerous CCR management units across the country, including ten of our potential units. The Vermilion ash ponds discussed below are the only unit which we believe qualify as a legacy CCR surface impoundment and given our closure plan for that site we do not believe the rule will have any impact on that site. CCRMUs with 1,000 or more tons of CCR must comply with the CCR's groundwater monitoring, corrective action, closure and post-closure requirements. For CCRMUs, complete facility evaluation reports are due within 33 months after publication of the rule, initial groundwater reports are due January 31, 2029, and the deadline to initiate closure, if needed, will start in 2029. Closure of the CCRMUs may also be deferred beyond those dates depending on certain factors, including where the CCRMU is located beneath critical infrastructure. In addition, certain closures may not be required when closure was previously approved under a state program. Because facility evaluation reports will determine our unit-specific compliance obligations, we cannot determine them at this time. In August 2024, we, along with USWAG, several other generating companies, and 17 states, including Texas, filed a challenge to the rule in the D.C. Circuit Court. In February 2025, the D.C. Circuit Court granted an unopposed motion filed by the Department of Justice on behalf of the EPA, holding the litigation in abeyance for a period of 120 days while the new leadership at the EPA evaluates the rule and determines how it wishes to proceed.

MISO — In 2012, the Illinois Environmental Protection Agency (IEPA) issued violation notices alleging violations of groundwater standards onsite at our Baldwin and Vermilion facilities' CCR surface impoundments. These violation notices remain unresolved; however, in 2016, the IEPA approved our closure and post-closure care plans for the Baldwin old east, east, and west fly ash CCR surface impoundments. We have completed closure activities at those ponds at our Baldwin facility.

At our retired Vermilion facility, which was not potentially subject to the EPA's 2015 CCR rule until the aforementioned D.C. Circuit Court decision in August 2018, we submitted proposed corrective action plans involving closure of two CCR surface impoundments (*i.e.*, the old east and the north impoundments) to the IEPA in 2012, and we submitted revised plans in 2014. In May 2017, in response to a request from the IEPA for additional information regarding the closure of these Vermilion surface impoundments, we agreed to perform additional groundwater sampling and closure options and riverbank stabilizing options. In June 2018, the IEPA issued a violation notice for alleged seep discharges claimed to be coming from the surface impoundments at our retired Vermilion facility, which is owned by our subsidiary DMG, and that notice was referred to the Illinois Attorney General. In June 2021, the Illinois Attorney General and the Vermilion County State Attorney filed a complaint in Illinois state court with an agreed interim consent order which the court subsequently entered. Given the violation notices and the enforcement action, the unique characteristics of the site, and the proximity of the site to the only national scenic river in Illinois, we agreed to enter into the interim consent order to resolve this matter. Per the terms of the agreed interim consent order, DMG is required to evaluate the closure alternatives under the requirements of the Illinois Coal Ash regulation (discussed below) and close the site by removal. In addition, the interim consent order requires that during the impoundment closure process, impacted groundwater will be collected before it leaves the site or enters the nearby Vermilion river and, if necessary, DMG will be required to install temporary riverbank protection if the river migrates within a certain distance of the impoundments. The interim order was modified in December 2022 to require certain amendments to the Safety Emergency Response Plan. In June 2023, the Illinois state court approved and entered the final consent order, which included the terms above and a requirement that when IEPA issues a final closure permit for the site, DMG will demolish the power station and submit for approval to construct an on-site landfill within the footprint of the former plant to store and manage the coal ash. These proposed closure costs are reflected in the ARO in the consolidated balance sheets (see Note 13 for additional information).

In 2012, the IEPA issued violation notices alleging violations of groundwater standards at the Newton and Coffeen facilities' CCR surface impoundments. We are addressing these CCR surface impoundments in accordance with the federal CCR rule.

In July 2019, coal ash disposal and storage legislation in Illinois was enacted. The legislation addresses state requirements for the proper closure of coal ash ponds in the state of Illinois. The law tasks the IEPA and the IPCB to set up a series of guidelines, rules, and permit requirements for closure of ash ponds. Under the final rule, which was finalized and became effective in April 2021, coal ash impoundment owners would be required to submit a closure alternative analysis to the IEPA for the selection of the best method for coal ash remediation at a particular site. The rule does not mandate closure by removal at any site. In May 2021, we, along with other industry petitioners, filed an appeal in the Illinois Fourth Judicial District over certain provisions of the final rule. In March 2024, the Illinois Fourth Judicial District issued a decision denying the industry petitions. We do not anticipate any impacts from this decision. In October 2021, we filed operating permit applications for 18 impoundments as required by the Illinois coal ash rule, and filed construction permit applications for three of our sites in January 2022 and five of our sites in July 2022. One additional closure construction application was filed for our Baldwin facility in August 2023.

For all of the above CCR matters, if certain corrective action measures, including groundwater treatment or removal of ash, are required at any of our coal-fueled facilities, we may incur significant costs that could have a material adverse effect on our financial condition, results of operations, and cash flows. The Illinois coal ash rule was finalized in April 2021 and does not require removal. However, the rule required us to undertake further site-specific evaluations required by each program. We will not know the full range of decommissioning costs, including groundwater remediation, if any, that ultimately may be required under the Illinois rule until permit applications have been approved by the IEPA and as such, an estimate of such costs cannot be made. The CCR surface impoundment and landfill closure costs currently reflected in our existing ARO liabilities reflect the costs of closure methods that our operations and environmental services teams determined were appropriate based on the existing closure requirements at the time we recorded those ARO liabilities, and is reasonably possible for those to increase once the IEPA determines final closure requirements. Once the IEPA acts on our permit applications, we will reassess the decommissioning costs and adjust our ARO liabilities accordingly.

MISO 2015-2016 Planning Resource Auction

In May 2015, three complaints were filed at the FERC regarding the Zone 4 results for the 2015-2016 planning resource auction (PRA) conducted by MISO. Dynegy is a named party in one of the complaints. The complainants, Public Citizen, Inc., the Illinois Attorney General and Southwestern Electric Cooperative, Inc. (Complainants), challenged the results of the PRA as unjust and unreasonable, requested rate relief/refunds, and requested changes to the MISO planning resource auction structure going forward. Complainants also alleged that Dynegy may have engaged in economic or physical withholding in Zone 4 constituting market manipulation in the PRA. The Independent Market Monitor for MISO (MISO IMM), which was responsible for monitoring the PRA, determined that all offers were competitive and that no physical or economic withholding occurred. The MISO IMM also stated, in a filing responding to the complaints, that there is no basis for the remedies sought by the Complainants. We filed our answer to these complaints explaining that we complied fully with the terms of the MISO tariff in connection with the PRA and disputing the allegations. The Illinois Industrial Energy Consumers filed a related complaint at the FERC against MISO in June 2015 requesting prospective changes to the MISO tariff. Dynegy also responded to this complaint with respect to Dynegy's conduct alleged in the complaint.

In October 2015, the FERC issued an order of nonpublic, formal investigation (the investigation) into whether market manipulation or other potential violations of the FERC orders, rules and regulations occurred before or during the PRA.

In December 2015, the FERC issued an order on the complaints requiring a number of prospective changes to the MISO tariff provisions effective as of the 2016-2017 planning resource auction. The order did not address the arguments of the Complainants regarding the PRA and stated that those issues remained under consideration and would be addressed in a future order.

In July 2019, the FERC issued an order denying the remaining issues raised by the complaints and noted that the investigation into Dynegy was closed. The FERC found that Dynegy's conduct did not constitute market manipulation and the results of the PRA were just and reasonable because the PRA was conducted in accordance with MISO's tariff. A request for rehearing was denied by the FERC in March 2020. The order was appealed by Public Citizen, Inc. to the D.C. Circuit Court in May 2020, and Vistra, Dynegy and Illinois Power Marketing Company intervened in the case in June 2020. In August 2021, the D.C. Circuit Court issued a ruling denying Public Citizen, Inc.'s arguments that the FERC failed to meet its obligation to ensure just and reasonable rates because it did not review the prices resulting from the auction before those prices went into effect and that the FERC was arbitrary and capricious in failing to adequately explain its decision to close its investigation into whether Dynegy engaged in market manipulation. The D.C. Circuit Court of Appeals granted Public Citizen, Inc.'s petition in part finding that the FERC's decision that the auction results were just and reasonable solely because the auction process complied with the filed tariff was unreasoned and remanded the case back to the FERC for further proceedings on that issue. On February 4, 2022 the Illinois Attorney General and Public Citizen, Inc. filed a motion at the FERC requesting that the FERC on remand reverse its prior decision and either find that auction results were not just and reasonable and order Dynegy to pay refunds to Illinois or, in the alternative, initiate an evidentiary hearing and discovery. In June 2022, the FERC issued an order on remand establishing paper hearing procedures and directing the Office of Enforcement to file a remand report within 90 days providing the Office of Enforcement's assessment of Dynegy's actions with regard to the 2015-2016 planning resource auction. Although the FERC directed the Office of Enforcement to file a remand report, the FERC stated in the June 2022 order that it is not reopening the Office of Enforcement investigation. In September 2022, the Office of Enforcement filed its remand report stating that the Office of Enforcement staff found during its investigation that Dynegy knowingly engaged in manipulative behavior to set the Zone 4 price in the 2015-2016 PRA. In June 2023, the Company filed its initial brief and response to the remand report, and in August 2023 the Company filed a reply to the initial briefs from other parties. In June 2024, the FERC issued an order for an evidentiary hearing (or a trial before a FERC administrative law judge) to determine what the FERC cited as "disputed issues of material fact" that it believes cannot be resolved on the existing record and, in October 2024, issued an order dismissing our request for rehearing of the June 2024 order. We will continue to vigorously defend our position.

Other Matters

We are involved in various legal and administrative proceedings and other disputes in the normal course of business, the ultimate resolutions of which, in the opinion of management, are not anticipated to have a material effect on our results of operations, liquidity, or financial condition.

Labor Contracts

We employ certain personnel who are represented by labor unions, the terms of whose employment are governed by collective bargaining agreements. The terms of all current collective bargaining agreements covering represented personnel engaged in lignite mining operations, lignite-, coal-, natural gas-, and nuclear-fueled generation operations, as well as some battery operations, expire on various dates between February 2025 and March 2028, but remain effective thereafter unless and until terminated by either party. While we cannot predict the outcome of labor contract negotiations, we do not expect any changes in our existing agreements to have a material adverse effect on our results of operations, liquidity, or financial condition.

Nuclear Insurance

Nuclear insurance includes nuclear liability coverage, property damage, nuclear accident decontamination, and accidental premature decommissioning coverage, and accidental outage and/or extra expense coverage. We maintain nuclear insurance that meets or exceeds requirements promulgated by Section 170 (Price-Anderson) of the Atomic Energy Act (the Act) and Title 10 of the Code of Federal Regulations. We intend to maintain insurance against nuclear risks as long as such insurance is available. We are self-insured to the extent that losses (i) are within the policy deductibles, (ii) are not covered per policy exclusions, terms and limitations, (iii) exceed the amount of insurance maintained, or (iv) are not covered due to lack of insurance availability. Any such self-insured losses could have a material adverse effect on our results of operations, liquidity, or financial condition.

With regard to nuclear liability coverage, the Act provides for financial protection for the public in the event of a significant nuclear generation plant incident. The Act sets the statutory limit of public liability for a single nuclear incident at $16.2 billion and requires nuclear generation plant operators to provide financial protection for this amount. However, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims that exceed the $16.2 billion limit for a single incident. As required, we insure against a possible nuclear incident at our nuclear facilities resulting in public nuclear-related bodily injury and property damage through a combination of private insurance and an industry-wide retrospective payment plan known as Secondary Financial Protection (SFP).

Under the SFP, in the event of any single nuclear liability loss in excess of $500 million at any nuclear generation facility in the U.S., each operating licensed reactor in the U.S. is subject to an assessment of up to $165.9 million. This approximately $165.9 million maximum assessment is subject to increases for inflation every five years, with the next expected adjustment scheduled to occur by November 2028. Assessments are currently limited to $24.7 million per operating licensed reactor per year per incident. As of December 31, 2024, our maximum potential assessment under the industry retrospective plan would be approximately $995.4 million per incident but no more than $148.2 million in any one year for each incident. The potential assessment is triggered by a nuclear liability loss in excess of $500 million per accident at any nuclear facility.

The United States Nuclear Regulatory Commission (NRC) requires that nuclear generation plant license holders maintain at least $1.06 billion of nuclear accident decontamination and reactor damage stabilization insurance, and requires that the proceeds thereof be used to place a plant in a safe and stable condition, to decontaminate a plant pursuant to a plan submitted to, and approved by, the NRC prior to using the proceeds for plant repair or restoration, or to provide for premature decommissioning. We maintain nuclear accident decontamination and reactor damage stabilization insurance for our Comanche Peak facility in the amount of $2.25 billion and non-nuclear accident related property damage in the amount of $1.0 billion (subject to a $5 million deductible per accident except for natural hazards which are subject to a $9.5 million deductible per accident), and losses excluded or above such limits are self-insured. We maintain nuclear accident decontamination and reactor damage stabilization insurance and non-nuclear accident related property damage for our Beaver Valley, Davis-Besse and Perry facilities in the amount of $1.5 billion each (subject to a $20 million deductible per accident), and losses excluded or above such limits are self-insured.

We also maintain Accidental Outage insurance to help cover the additional costs of obtaining replacement electricity from another source if the units are out of service for more than twelve weeks as a result of covered direct physical damage. Coverage at Comanche Peak provides for weekly payments per unit up to $4.5 million for the first 52 weeks and up to $2.7 million for a remaining 21 weeks for non-nuclear and up to $3.6 million for a remaining 71 weeks for nuclear property damage outages. The total maximum coverage is $291 million for non-nuclear property damage and $490 million for nuclear property damage outages. Coverage at Beaver Valley, Davis-Besse and Perry facilities provide for weekly payments per unit up to $2.5 million for the first 52 weeks and up to $1.5 million for a remaining 52 weeks for non-nuclear and up to $2 million for a remaining 110 weeks for nuclear property damage outages. The total maximum coverage is $208 million for non-nuclear property damage and $350 million for nuclear damage outages. There are two units at Comanche Peak and Beaver Valley, and coverage amounts applicable to each unit will reduce to 80% if both units are out of service at the same time as a result of the same accident.

16. EQUITY

Common Stock

Issuances and Repurchases

Changes in the number of shares of common stock issued and outstanding for the years ended December 31, 2024, 2023, and 2022 are reflected in the table below.

	Shares Issued	Treasury Shares	Shares Outstanding
Balance at December 31, 2021	532,929,476	(69,031,742)	463,897,734
Shares issued (a)	4,262,575	—	4,262,575
Shares retired	(12,979)	—	(12,979)
Shares repurchased (b)	—	(78,470,547)	(78,470,547)
Balance at December 31, 2022	537,179,072	(147,502,289)	389,676,783
Shares issued (a)	6,474,491	—	6,474,491
Shares retired	(18,391)	—	(18,391)
Shares repurchased (b)	—	(44,994,499)	(44,994,499)
Balance at December 31, 2023	543,635,172	(192,496,788)	351,138,384
Shares issued (a)	5,117,434	—	5,117,434
Shares repurchased (b)	—	(16,560,328)	(16,560,328)
Balance at December 31, 2024	548,752,606	(209,057,116)	339,695,490

(a) Shares issued include share awards granted to nonemployee directors.
(b) Shares repurchased include 58,817, 318,632, and 78,087 of unsettled shares as of December 31, 2024, 2023, and 2022, respectively.

C*ommon Stock Dividends*

Dividends are subject to declaration by the Board and may be subject to numerous factors at the time of declaration. These factors include, but are not limited to, prevailing market conditions, Vistra's results of operations, financial condition and liquidity, Delaware law, and any contractual limitations, such as the cumulative dividend requirements described in the certificates of designation of our outstanding preferred stock. Dividends per common share totaled $0.8735, $0.8205, and $0.7240 in the years ended December 31, 2024, 2023, and 2022, respectively.

In February 2025, the Board declared a quarterly dividend of $0.2235 per share of common stock that will be paid in March 2025.

Share Repurchase Program

In October 2021, the Board authorized a share repurchase program (Share Repurchase Program). Under this program, shares of the Company's common stock may be repurchased in open market transactions, privately negotiated transactions, or other means in accordance with federal securities laws. The timing, number, and value of shares repurchased will be determined at our discretion, considering factors such as capital allocation priorities, stock market price, general market and economic conditions, legal requirements, and compliance with debt agreements and preferred stock certificates of designation.

	Amount Authorized for Share Repurchases
	(in billions)
Board Authorization Dates:	
October 2021	$ 2.00
August 2022	1.25
March 2023	1.00
February 2024	1.50
October 2024	1.00
Cumulative authorization at December 31, 2024	$ 6.75

The following table provides information about our repurchases of common stock for the period between January 1, 2022 and February 24, 2025.

	$6.750 Billion Board Authorization			
	Total Number of Shares Repurchased	Average Price Paid Per Share	Amount Paid for Shares Repurchased	Amount Available for Additional Repurchases at the End of the Period
	(in millions, except share amounts and price paid per share)			
Year Ended December 31, 2022	78,470,547	$ 23.40	$ 1,836	
Year Ended December 31, 2023	44,994,499	27.89	1,255	
Year Ended December 31, 2024	16,560,328	74.96	1,241	
January 1, 2022 through December 31, 2024 (a)	140,025,374	$ 30.94	$ 4,332	$ 2,009
January 1, 2025 through February 24, 2025	848,866	163.23	139	
January 1, 2022 through February 24, 2025	140,874,240	$ 31.74	$ 4,471	$ 1,870

(a) Shares repurchased include 58,817 of unsettled shares for $8 million as of December 31, 2024.

Preferred Stock

The following is a summary of our cumulative redeemable preferred stock outstanding. In the event of liquidation or dissolution of the Company, the payment of dividends and the distribution of assets to preferred stockholders takes precedence over the Company's common stockholders.

Preferred Stock Series	Issuance Date	Shares Issued and Outstanding (a)	Contractual Rates	Earliest Redemption Date (b)	Date at Which Dividend Rate Becomes Floating	Floating Annual Rates
Series A	October 15, 2021	1,000,000	8.000 %	October 15, 2026	October 15, 2026	5-Year U.S. Treasury rate (subject to floor of 1.07%) plus 6.93%
Series B	December 10, 2021	1,000,000	7.000 %	December 15, 2026	December 15, 2026	5-Year U.S. Treasury rate (subject to floor of 1.26%) plus 5.74%
Series C	December 29, 2023	476,066	8.875 %	January 15, 2029	January 15, 2029	5-Year U.S. Treasury rate (subject to floor of 3.83%) plus 5.045%

(a) Series C Preferred Stock issued totaled 476,081 shares at December 31, 2023.
(b) Subject to our right, in limited circumstances, to redeem preferred stock prior to the earliest redemption date.

Each series of preferred stock has a liquidation price of $1,000, plus accrued and unpaid dividends through their redemption date. Preferred stock is not convertible into or exchangeable for any other securities of the Company and has limited voting rights.

Preferred Stock Dividends

Preferred stock dividends are payable semiannually in arrears when declared by the Board. The following table summarizes preferred stock dividends paid per share in the years ended December 31, 2024, 2023, and 2022.

	Year Ended December 31,		
Preferred Stock Series	**2024**	**2023**	**2022**
Series A Preferred Stock	$ 80.00	$ 80.00	$ 80.00
Series B Preferred Stock	$ 70.00	$ 70.00	$ 70.97
Series C Preferred Stock	$ 48.32		

In October 2024, the Board declared a semi-annual dividend of $44.375 per share of Series C Preferred Stock that was paid in January 2025. In February 2025, the Board declared a semi-annual dividend of $40.00 per share of Series A Preferred Stock that will be paid in April 2025.

17. EARNINGS PER SHARE

Basic earnings per share available to common stockholders are based on the weighted average number of common shares outstanding during the period. Diluted earnings per share is calculated using the treasury stock method and includes the effect of all potential issuances of common shares under stock-based incentive compensation arrangements.

	Year Ended December 31,		
	2024	**2023**	**2022**
	(in millions, except share data)		
Net income (loss) attributable to Vistra	$ 2,659	$ 1,493	$ (1,227)
Less cumulative dividends attributable to Series A Preferred Stock	(80)	(80)	(80)
Less cumulative dividends attributable to Series B Preferred Stock	(70)	(70)	(70)
Less cumulative dividends attributable to Series C Preferred Stock	(42)	—	—
Net income (loss) attributable to common stock — basic and diluted	2,467	1,343	(1,377)
Weighted average shares of common stock outstanding:			
Basic	344,788,634	369,771,359	422,447,074
Dilutive securities: Stock-based incentive compensation plan	7,778,426	5,421,752	—
Diluted	352,567,060	375,193,110	422,447,074
Net income (loss) per weighted average share of common stock outstanding:			
Basic	$ 7.16	$ 3.63	$ (3.26)
Diluted	$ 7.00	$ 3.58	$ (3.26)

Stock-based incentive compensation plan awards excluded from the calculation of diluted earnings per share because the effect would have been antidilutive were immaterial in the year ended December 31, 2024 and were 392,218 and 8,292,647 shares for the years ended December 31, 2023 and 2022, respectively.

18. STOCK-BASED COMPENSATION

Vistra 2016 Omnibus Incentive Plan

On the Effective Date, the Board adopted the 2016 Omnibus Incentive Plan (2016 Incentive Plan), under which an aggregate of 22,500,000 shares of our common stock were reserved for issuance as equity-based awards to our non-employee directors, employees, and certain other persons. Following approval of the Board and approval by the stockholders at the 2019 and 2024 annual meetings of the Company, the 2016 Incentive Plan was amended to increase the maximum number of shares reserved for issuance under the 2016 Incentive Plan to 37,500,000 and 43,000,000, respectively. The Board or any committee duly authorized by the Board will administer the 2016 Incentive Plan and has broad authority under the 2016 Incentive Plan to, among other things: (a) select participants, (b) determine the types of awards that participants are to receive and the number of shares that are to be subject to such awards, and (c) establish the terms and conditions of awards, including the price (if any) to be paid for the shares of the award. The types of awards that may be granted under the 2016 Incentive Plan include stock options, RSUs, restricted stock, performance awards, and other forms of awards granted or denominated in shares of Vistra common stock, as well as certain cash-based awards.

If any stock option or other stock-based award granted under the 2016 Incentive Plan expires, terminates or is canceled for any reason without having been exercised in full, the number of shares of Vistra common stock underlying any unexercised award shall again be available for awards under the 2016 Incentive Plan. If any shares of restricted stock, performance awards or other stock-based awards denominated in shares of Vistra common stock awarded under the 2016 Incentive Plan are forfeited for any reason, the number of forfeited shares shall again be available for purposes of awards under the 2016 Incentive Plan. Any award under the 2016 Incentive Plan settled in cash shall not be counted against the maximum share limitation. No awards under the 2016 Incentive Plan have been settled in cash since the Effective Date.

As is customary in incentive plans of this nature, each share limit and the number and kind of shares available under the 2016 Incentive Plan and any outstanding awards, as well as the exercise or purchase price of awards, and performance targets under certain types of performance-based awards, are required to be adjusted in the event of certain reorganizations, mergers, combinations, recapitalizations, stock splits, stock dividends or other similar events that change the number or kind of shares outstanding, and extraordinary dividends or distributions of property to the Vistra stockholders.

Stock-Based Compensation Expense

Stock-based compensation expense is reported as SG&A in the consolidated statements of operations as follows:

	Year Ended December 31,		
	2024	2023	2022
	(in millions)		
Total stock-based compensation expense	$ 100	$ 77	$ 65
Income tax benefit	(23)	(18)	(15)
Stock based-compensation expense, net of tax	$ 77	$ 59	$ 50

Stock Options

Stock options outstanding at December 31, 2024 are all held by current or former employees. The following table summarizes our stock option activity:

	Year Ended December 31, 2024			
	Stock Options (in thousands)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (in millions)
Total outstanding at beginning of period	6,126	$ 20.01	4.2	$ 113.5
Exercised	(2,526)	$ 20.06		
Total outstanding at end of period	3,600	$ 19.97	3.5	$ 424.4
Exercisable at December 31, 2024	3,600	$ 19.97	3.5	$ 424.4

As of December 31, 2024, there was no unrecognized compensation cost related to unvested stock options granted under the 2016 Incentive Plan and no new options were issued in the three years ended December 31, 2024.

Restricted Stock Units

The following table summarizes our restricted stock unit activity:

	Year Ended December 31, 2024	
	Restricted Stock Units (in thousands)	Weighted Average Grant Date Fair Value
Total nonvested at beginning of period	3,908	$ 21.90
Granted	1,017	$ 59.11
Vested	(1,785)	$ 22.20
Forfeited	(86)	$ 33.55
Total nonvested at end of period	3,054	$ 34.30

As of December 31, 2024, $61 million of unrecognized compensation cost related to unvested restricted stock units granted under the 2016 Incentive Plan are expected to be recognized over a weighted average period of approximately 2.0 years.

Performance Stock Units

We also issue Performance Stock Units (PSUs) to certain members of management on an annual basis. All PSUs have a three year performance period and a payout opportunity of 0-200% of target (100%), which is intended to be settled in shares of Vistra common stock. We recognized compensation expense associated with PSUs of $54 million, $36 million, and $22 million for the years ended December 31, 2024, 2023, and 2022, respectively. As of December 31, 2024, we have $64 million of unrecognized compensation cost associated with PSUs.

19. SEGMENT INFORMATION

The operations of Vistra are aligned into five reportable business segments: (i) Retail, (ii) Texas, (iii) East, (iv) West, and (v) Asset Closure. In the fourth quarter of 2024, we updated our reportable segments to reflect changes in how the Company's CODM makes operating decisions, assesses performance, and allocates resources by removing the Sunset segment. The results of the plants previously included in the Sunset segment are now reflected in the Texas and East segments based on their respective geography.

Our Chief Executive Officer is our CODM. Our CODM reviews the results of these segments separately and allocates resources to the respective segments as part of our strategic operations. A measure of assets is not applicable, as segment assets are not regularly reviewed by the CODM for evaluating performance or allocating resources.

The Retail segment is engaged in retail sales of electricity and natural gas to residential, commercial and industrial customers. Substantially all of these activities are conducted by TXU Energy, Ambit, Dynegy Energy Services, Homefield Energy, Energy Harbor, and U.S. Gas & Electric across 16 states and the District of Columbia.

The Texas and East segments are engaged in electricity generation, wholesale energy sales and purchases, commodity risk management activities, fuel procurement, and logistics management. The Texas segment represents results from all of Vistra's electricity generation operations in the ERCOT market except for assets included in the Asset Closure segments. The East segment represents results from Vistra's electricity generation operations in the Eastern Interconnection of the U.S. electric grid, other than assets included in the Asset Closure segment, and includes operations in the PJM, MISO, ISO-NE, and NYISO markets.

The West segment represents results from the CAISO market, including our battery ESS projects at our Moss Landing power plant site.

The Asset Closure segment is engaged in the decommissioning and reclamation of retired plants and mines (see Note 6 for additional information). Upon movement of generation plant assets to the Asset Closure segment, prior year results are retrospectively adjusted, if the effects are material, for comparative purposes. Separately reporting the Asset Closure segment provides management with better information related to the performance and earnings power of Vistra's ongoing operations and facilitates management's focus on minimizing the cost associated with decommissioning and reclamation of retired plants and mines.

Corporate and Other represents the remaining non-segment operations consisting primarily of general corporate expenses, interest, taxes and other expenses not allocated to our operating segments.

The accounting policies of the business segments are the same as those described in the summary of significant accounting policies in Note 1. Our CODM uses more than one measure to assess segment performance, but primarily focuses on Adjusted EBITDA. While we believe this is a useful metric in evaluating operating performance, it is not a metric defined by U.S. GAAP and may not be comparable to non-GAAP metrics presented by other companies. Adjusted EBITDA is most comparable to consolidated Net income (loss) prepared based on U.S. GAAP. The CODM uses net income in competitive analysis by benchmarking to the Company's competitors and in evaluating drivers of segment profits available to the Company's equity holders. We account for intersegment sales and transfers as if the sales or transfers were to third parties, that is, at market prices. Certain shared services costs are allocated to the segments. Substantially all income tax (expense) benefit is recognized in Corporate and Other.

	Year Ended December 31, 2024							
	Retail	Texas	East	West	Asset Closure	Total Reportable Segments	Corporate and Other	Total
	(in millions)							
Operating revenues	$ 12,797	$ 5,394	$ 5,661	$ 877	$ 1	$ 24,730	$ (7,506)	$ 17,224
Fuel, purchased power costs, and delivery fees	(10,276)	(1,596)	(2,698)	(221)	(3)	(14,794)	7,509	(7,285)
Operating costs	(159)	(996)	(1,103)	(72)	(81)	(2,411)	(3)	(2,414)
Selling, general, and administrative expenses	(977)	(169)	(148)	(25)	(43)	(1,362)	(239)	(1,601)
Other segment items:								
Depreciation and amortization	(114)	(581)	(996)	(86)	—	(1,777)	(66)	(1,843)
Interest expenses and related charges	(54)	46	9	1	(4)	(2)	(898)	(900)
Income tax expense	—	—	—	—	—	—	(655)	(655)
Other (a)	(1)	35	177	(3)	14	222	64	286
Net income (loss)	$ 1,216	$ 2,133	$ 902	$ 471	$ (116)	$ 4,606	$ (1,794)	$ 2,812
Capital expenditures, including nuclear fuel and excluding growth expenditures	$ 4	$ 1,124	$ 661	$ 70	$ —	$ 1,859	$ 58	$ 1,917

	Year Ended December 31, 2023							
	Retail	Texas	East	West	Asset Closure (b)	Total Reportable Segments	Corporate and Other	Total
	(in millions)							
Operating revenues	$ 10,572	$ 3,979	$ 5,890	$ 914	$ —	$ 21,355	$ (6,576)	$ 14,779
Fuel, purchased power costs, and delivery fees	(9,046)	(2,028)	(2,730)	(328)	(3)	(14,135)	6,578	(7,557)
Operating costs	(123)	(917)	(528)	(58)	(74)	(1,700)	(2)	(1,702)
Selling, general, and administrative expenses	(858)	(140)	(127)	(24)	(34)	(1,183)	(125)	(1,308)
Other segment items:								
Depreciation and amortization	(102)	(550)	(703)	(79)	—	(1,434)	(68)	(1,502)
Interest expenses and related charges	(20)	21	(2)	8	(5)	2	(742)	(740)
Income tax expense	—	—	(1)	—	—	(1)	(507)	(508)
Other (a)	1	33	(50)	21	110	115	(85)	30
Net income (loss)	$ 424	$ 398	$ 1,749	$ 454	$ (6)	$ 3,019	$ (1,527)	$ 1,492
Capital expenditures, including nuclear fuel and excluding growth expenditures	$ 1	$ 750	$ 362	$ 366	$ —	$ 1,479	$ 58	$ 1,537

	Year Ended December 31, 2022							
	Retail	Texas	East	West	Asset Closure (b)	Total Reportable Segments	Corporate and Other	Total
	(in millions)							
Operating revenues	$ 9,455	$ 3,878	$ 4,429	$ 336	$ 384	$ 18,482	$ (4,754)	$ 13,728
Fuel, purchased power costs, and delivery fees	(7,169)	(3,052)	(4,132)	(481)	(322)	(15,156)	4,755	(10,401)
Operating costs	(143)	(832)	(482)	(42)	(145)	(1,644)	(1)	(1,645)
Selling, general, and administrative expenses	(826)	(135)	(97)	(21)	(44)	(1,123)	(66)	(1,189)
Other segment items:								
Interest expenses and related charges	(14)	20	(6)	6	(3)	3	(371)	(368)
Depreciation and amortization	(145)	(541)	(768)	(42)	(31)	(1,527)	(69)	(1,596)
Income tax benefit	—	—	—	—	—	—	350	350
Other (a)	—	76	(71)	6	14	25	(114)	(89)
Net income (loss)	$ 1,158	$ (586)	$ (1,127)	$ (238)	$ (147)	$ (940)	$ (270)	$ (1,210)
Capital expenditures, including nuclear fuel and excluding growth expenditures	$ 1	$ 520	$ 187	$ 345	$ —	$ 1,053	$ 55	$ 1,108

(a) Other includes impairment of long-lived assets, other income, other deductions, and the impacts of the Tax Receivable Agreement.
(b) We have allocated unrealized gains and losses on the commodity risk management activities attributable to the plants retired in 2022 and 2023. See Note 6 for additional information.

20. SUPPLEMENTARY FINANCIAL INFORMATION

Other Income and Deductions

	Year Ended December 31,		
	2024	2023	2022
	(in millions)		
Other income:			
NDT net income (a)	$ 170	$ —	$ —
Insurance settlements (b)	23	24	70
Gain on sale of land (c)	6	95	8
Gain on TRA settlement (d)	10	29	—
Interest income	65	86	19
All other	38	23	20
Total other income	$ 312	$ 257	$ 117
Other deductions:			
All other	$ 21	$ 14	$ 4
Total other deductions	$ 21	$ 14	$ 4

(a) Includes interest, dividends, and net realized and unrealized gains and losses associated with NDTs of the PJM nuclear facilities. Reported in the East segment.
(b) For the year ended December 31, 2024, $20 million reported in the Texas segment and $3 million reported in the West segment. For the year ended December 31, 2023, $19 million reported in the West segment and $5 million in the Asset Closure segment. For the year ended December 31, 2022, $62 million reported in the Texas segment, $6 million reported in the West segment, $1 million reported in the Asset Closure segment, and $1 million reported in the Corporate and Other non-segment.

(c) For the year ended December 31, 2024, reported in the Asset Closure segment. For the year ended December 31, 2023, $94 million reported in the Asset Closure segment and $1 million reported in the Texas segment. For the year ended December 31, 2022, reported in the Asset Closure segment.
(d) Reported in the Corporate and Other.

Inventories by Major Category

	December 31, 2024	December 31, 2023
	(in millions)	
Materials and supplies	$ 533	$ 289
Fuel stock	403	420
Natural gas in storage	34	31
Total inventories	$ 970	$ 740

Investments

	December 31, 2024	December 31, 2023
	(in millions)	
Nuclear decommissioning trusts	$ 4,440	$ 1,951
Assets related to employee benefit plans	14	28
Land investments	42	42
Other investments	16	14
Total investments	$ 4,512	$ 2,035

Other Noncurrent Liabilities and Deferred Credits

The balance of other noncurrent liabilities and deferred credits consists of the following:

	December 31, 2024	December 31, 2023
	(in millions)	
Retirement and other employee benefits (Note 14)	$ 224	$ 247
Winter Storm Uri impact (a)	1	26
Identifiable intangible liabilities (Note 7)	155	131
Regulatory liability (b)	452	209
Operating lease liabilities	98	48
Finance lease liabilities	218	227
Liability for third-party remediation	8	17
Accrued severance costs	36	36
Other accrued expenses	64	58
Total other noncurrent liabilities and deferred credits	$ 1,256	$ 999

(a) Includes future bill credits related to large commercial and industrial customers that curtailed during Winter Storm Uri.
(b) As of December 31, 2024, the fair value of the assets contained in the Comanche Peak NDT was higher than the carrying value of our ARO related to our nuclear generation plant decommissioning and recorded as a regulatory liability of $452 million and $209 million, respectively, in other noncurrent liabilities and deferred credits.

Supplemental Cash Flow Information

The following table reconciles cash, cash equivalents and restricted cash reported in the consolidated statements of cash flows to the amounts reported in the consolidated balance sheets at December 31, 2024 and 2023:

	December 31,	
	2024	2023
	(in millions)	
Cash and cash equivalents	$ 1,188	$ 3,485
Restricted cash included in current assets (a)	28	40
Restricted cash included in noncurrent assets (a)	6	14
Total cash, cash equivalents and restricted cash	$ 1,222	$ 3,539

(a) Restricted cash consists of amounts related to remediation escrow accounts. Vistra has transferred various asset retirement obligations related to several closed plant sites to a third-party remediation company. As part of certain transfers, Vistra deposits funds into escrow accounts, and the funds are released to the remediation company as milestones are reached in the remediation process. Amounts contractually payable to the third party in exchange for assuming the obligations are included in other current liabilities and other noncurrent liabilities and deferred credits.

The following table summarizes our supplemental cash flow information for the years ended December 31, 2024, 2023, and 2022, respectively. Non-cash investing and financing activities also includes activity related to the Energy Harbor Merger. See Note 2 for additional information.

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Cash payments related to:			
Interest paid	$ 987	$ 636	$ 581
Capitalized interest	(77)	(37)	(29)
Interest paid (net of capitalized interest)	$ 910	$ 599	$ 552
Non-cash investing and financing activities:			
Accrued property, plant, and equipment additions (a)	$ 258	$ 104	$ 103
Issuance of Series C Preferred Stock as consideration for the repurchase of TRA Rights with a carrying value of $506 million	$ —	$ 476	$ —
Book value of property, plant, and equipment sold, including nuclear fuel	$ 117	$ 26	$ —

(a) Represents property, plant, and equipment accruals during the period for which cash has not been paid as of the end of the period.

For the years ended December 31, 2024, 2023, and 2022, we paid federal income taxes of $5 million, zero, and $1 million, respectively, paid state income taxes of $59 million, $44 million, and $33 million, respectively, and received state tax refunds of $9 million, $13 million, and $8 million, respectively.

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

None.

Item 9A. CONTROLS AND PROCEDURES

An evaluation was performed under the supervision and with the participation of our management, including the principal executive officer and principal financial officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15a-15(e) of the Exchange Act) in effect at December 31, 2024. Based on the evaluation performed, our principal executive officer and principal financial officer concluded that the disclosure controls and procedures were effective as of that date.

Other than additional controls associated with the Energy Harbor Merger, there have been no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(e) and 15a-15(e) of the Exchange Act) during the most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

VISTRA CORP.
MANAGEMENT'S ANNUAL REPORT ON
INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Vistra Corp. is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) for the company. Vistra Corp.'s internal control over financial reporting is 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. 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 condition or the deterioration of compliance with procedures or policies.

The management of Vistra Corp. performed an evaluation of the effectiveness of the company's internal control over financial reporting as of December 31, 2024 based on the Committee of Sponsoring Organizations of the Treadway Commission's (COSO's) *Internal Control - Integrated Framework (2013)*. Based on the review performed, management believes that as of December 31, 2024 Vistra Corp.'s internal control over financial reporting was effective.

On March 1, 2024, a wholly owned subsidiary of Vistra Corp. merged with and into Energy Harbor, as further described in Note 2. Energy Harbor's financial statements consolidated by Vistra Corp represent approximately 1% of the company's total assets as of December 31, 2024 and approximately 11% of the company's total revenues for the year then ended, excluding balance sheet accounts subjected to purchase accounting controls. As permitted by the SEC, management has elected to exclude Energy Harbor from its assessment of the effectiveness of its internal control over financial reporting as of December 31, 2024.

The independent registered public accounting firm of Deloitte & Touche LLP as auditors of the consolidated financial statements of Vistra Corp. has issued an attestation report on Vistra Corp.'s internal control over financial reporting.

/s/ JAMES A. BURKE	/s/ KRISTOPHER E. MOLDOVAN
James A. Burke	Kristopher E. Moldovan
President and Chief Executive Officer	Chief Financial Officer
(Principal Executive Officer)	(Principal Financial Officer)

February 27, 2025

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Vistra Corp.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Vistra Corp. and subsidiaries (the “Company”) 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 (COSO). 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 COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2024, of the Company and our report dated February 27, 2025, expressed an unqualified opinion on those financial statements.

As described in Management’s Annual Report on Internal Control over Financial Reporting, management excluded from its assessment the internal control over financial reporting at Energy Harbor Holdings LLC (formerly known as Energy Harbor Corp.), which was acquired on March 1, 2024, and whose financial statements represent approximately 1% of total assets and approximately 11% of revenues of the consolidated financial statement amounts, excluding balance sheet accounts subjected to purchase accounting controls, as of and for the year ended December 31, 2024. Accordingly, our audit did not include the internal control over financial reporting at Energy Harbor Holdings LLC.

Basis for Opinion

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

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Deloitte & Touche LLP

Dallas, Texas
February 27, 2025

Item 9B. OTHER INFORMATION

During the three months ended December 31, 2024, none of our officers or directors adopted or terminated any contract, instruction, or written plan for the purchase or sale of Company securities that was intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) or any "non-Rule 10b5-1 trading arrangement", except as set forth below.

On December 17, 2024, Kristopher Moldovan, Executive Vice President and Chief Financial Officer of the Company, entered into a trading plan intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) of the Exchange Act (the 10b5-1 Plan). The 10b5-1 Plan provides for the potential exercise and sale of options for up to 139,925 shares of our common stock pursuant to stock option awards that will be expiring over the next several years. Any sales are subject to certain price limitations set forth in the 10b5-1 Plan such that the actual number of shares sold could vary if certain minimum stock prices are not met. The 10b5-1 Plan will become effective on March 18, 2025 and will terminate on November 28, 2025, subject to earlier termination as provided in the 10b5-1 Plan. The 10b5-1 Plan was entered into during an open insider trading window in accordance with our Transactions in Securities Policy.

Item 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Code of Ethics

Vistra has adopted a code of ethics entitled "Vistra Code of Conduct" that applies to directors, officers, and employees, including the chief executive officer and senior financial officers of Vistra. It may be accessed through the "Corporate Governance" section of the Company's website at *www.vistracorp.com*. Vistra also elects to disclose the information required by Form 8-K, Item 5.05, "Amendments to the Registrant's Code of Ethics, or Waiver of a Provision of the Code of Ethics," through the Company's website and will disclose such events within four business days following the date of the amendment or waiver, and such information will remain available on this website for at least a 12-month period. A copy of the "Vistra Code of Conduct" is available in print to any stockholder who requests it.

Other information required by this Item is incorporated by reference to the similarly named section of Vistra Definitive Proxy Statement for its 2025 Annual Meeting of Stockholders.

Item 11. EXECUTIVE COMPENSATION

Information required by this Item is incorporated by reference to the similarly named section of Vistra's Definitive Proxy Statement for its 2025 Annual Meeting of Stockholders.

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

Information required by this Item is incorporated by reference to the sections entitled "Beneficial Ownership of Common Stock of the Company" in Vistra's Definitive Proxy Statement for its 2025 Annual Meeting of Stockholders.

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

Information required by this Item is incorporated by reference to the sections entitled "Business Relationships and Related Person Transactions Policy" and "Director Independence" in Vistra's Definitive Proxy Statement for its 2025 Annual Meeting of Stockholders.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by this Item is incorporated by reference to the sections entitled "Principal Accountant Fees" in Vistra's Definitive Proxy Statement for its 2025 Annual Meeting of Stockholders.

Deloitte & Touche LLP's PCAOB ID Number is 34.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Our financial statements and financial statement schedules are incorporated under Part II, Item 8 of this annual report on Form 10-K.

(b) **SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT**

VISTRA CORP. (PARENT)
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF OPERATIONS
(Millions of Dollars)

	Year Ended December 31,		
	2024	2023	2022
Depreciation and amortization	$ —	$ (15)	$ (16)
Selling, general, and administrative expenses	(102)	(80)	(69)
Operating loss	(102)	(95)	(85)
Other income	28	31	6
Impacts of Tax Receivable Agreement	(5)	(164)	(128)
Loss before income tax benefit	(79)	(228)	(207)
Income tax benefit	17	58	47
Equity in earnings (losses) of subsidiaries, net of tax	2,721	1,663	(1,067)
Net income (loss)	$ 2,659	$ 1,493	$ (1,227)

See Notes to the Condensed Financial Statements.

VISTRA CORP. (PARENT)
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED BALANCE SHEETS
(Millions of Dollars)

	December 31,	
	2024	2023
ASSETS		
Cash and cash equivalents	$ 22	$ 31
Trade accounts receivable — affiliates	13	—
Income taxes receivable	8	6
Total current assets	43	37
Investment in affiliated companies	4,670	4,507
Property, plant, and equipment — net	2	3
Accumulated deferred income taxes	960	1,086
Other noncurrent assets	3	—
Total assets	$ 5,678	$ 5,633
LIABILITIES AND EQUITY		
Trade accounts payable	$ 8	$ 12
Accounts payable —affiliates	27	91
Accrued taxes	9	12
Other current liabilities	27	12
Total current liabilities	71	127
Tax Receivable Agreement obligations	14	164
Other noncurrent liabilities and deferred debits	10	20
Total liabilities	95	311
Total stockholders' equity	5,583	5,322
Total liabilities and equity	$ 5,678	$ 5,633

See Notes to the Condensed Financial Statements.

VISTRA CORP. (PARENT)
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF CASH FLOWS
(Millions of Dollars)

	Year Ended December 31,		
	2024	2023	2022
Cash flows — operating activities:			
Cash used in operating activities	$ (37)	$ (31)	$ (27)
Cash flows — investing activities:			
Dividend received from subsidiaries	1,705	1,625	1,775
Proceeds from sales of subsidiary transferable ITCs	150	—	—
Cash provided by investing activities	1,855	1,625	1,775
Cash flows — financing activities:			
Stock repurchases	(1,266)	(1,245)	(1,949)
Dividends paid to common stockholders	(305)	(313)	(302)
Dividends paid to preferred stockholders	(173)	(150)	(151)
TRA Repurchase and tender offer - return of capital	(122)	—	—
Other, net	39	91	40
Cash used in financing activities	(1,827)	(1,617)	(2,362)
Net change in cash, cash equivalents and restricted cash	(9)	(23)	(614)
Cash, cash equivalents and restricted cash — beginning balance	31	54	668
Cash, cash equivalents and restricted cash — ending balance	$ 22	$ 31	$ 54

See Notes to the Condensed Financial Statements.

NOTES TO CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

The accompanying unconsolidated condensed balance sheets, statements of net loss and cash flows present results of operations and cash flows of Vistra Corp. (Parent). Certain information and footnote disclosures normally included in financial statements prepared in accordance with U.S. GAAP have been omitted pursuant to the rules of the SEC. Because the unconsolidated condensed financial statements do not include all of the information and footnotes required by U.S. GAAP, they should be read in conjunction with the financial statements and related notes of Vistra Corp. and Subsidiaries included in the annual report on Form 10-K for the year ended December 31, 2024. Vistra Corp.'s subsidiaries have been accounted for under the equity method. All dollar amounts in the financial statements and tables in the notes are stated in millions of U.S. dollars unless otherwise indicated.

Vistra Corp. (Parent) files a consolidated U.S. federal income tax return. Consolidated tax expenses or benefits and deferred tax assets or liabilities have been allocated to the respective subsidiaries in accordance with the accounting rules that apply to separate financial statements of subsidiaries.

2. RESTRICTIONS ON SUBSIDIARIES

The Vistra Operations Credit Agreement generally restricts the ability of Vistra Operations to make distributions to any direct or indirect parent unless such distributions are expressly permitted thereunder. As of December 31, 2024, Vistra Operations can distribute approximately $8.2 billion to Vistra Corp. (Parent) under the Vistra Operations Credit Agreement without the consent of any party. The amount that can be distributed by Vistra Operations to Parent was partially reduced by distributions made by Vistra Operations to Vistra Corp. (Parent) of approximately $1.705 billion, $1.625 billion, and $1.775 billion during the years ended December 31, 2024, 2023, and 2022, respectively. Additionally, Vistra Operations may make distributions to Vistra Corp. (Parent) in amounts sufficient for Vistra Corp. (Parent) to make any payments required under the TRA or the Tax Matters Agreement or, to the extent arising out of Vistra Corp. (Parent)'s ownership or operation of Vistra Operations, to pay any taxes or general operating or corporate overhead expenses. As of December 31, 2024, all of the restricted net assets of Vistra Operations may be distributed to Vistra Corp. (Parent).

3. GUARANTEES

Vistra Corp. (Parent) has entered into contracts that contain guarantees to unaffiliated parties that could require performance or payment under certain conditions. As of December 31, 2024, there are no material outstanding claims related to guarantee obligations of Vistra Corp. (Parent), and Vistra Corp. (Parent) does not anticipate it will be required to make any material payments under these guarantees in the near term.

4. DIVIDEND RESTRICTIONS

Under applicable law, Vistra Corp. (Parent) is prohibited from paying any dividend to the extent that immediately following payment of such dividend there would be no statutory surplus or Vistra Corp. (Parent) would be insolvent.

Vistra Corp. (Parent) received $1.705 billion, $1.625 billion, and $1.775 billion in dividends from its consolidated subsidiaries in the years ended December 31, 2024, 2023, and 2022, respectively.

(c) **EXHIBITS:**

Vistra Corp. Exhibits to Form 10-K for the Fiscal Year Ended December 31, 2024

Exhibits	Previously Filed With File Number*	As Exhibit		
(2)	**Plan of Acquisition, Reorganization, Arrangement, Liquidation, or Succession**			
2.1	001-38086 Form 8-K (filed March 7, 2023)	2.1	—	Transaction Agreement, dated March 6, 2023, by and among Vistra Operations Company LLC, Black Pen Inc. and Energy Harbor Corp.
(3(i))	**Articles of Incorporation**			
3.1	001-38086 Form 8-K (filed May 4, 2020)	3.1	—	Restated Certificate of Incorporation of Vistra Energy Corp. (now known as Vistra Corp.)
3.2	001-38086 Form 8-K (filed June 29, 2020)	3.1	—	Certificate of Amendment of the Restated Certificate of Incorporation of Vistra Energy Corp. (now known as Vistra Corp.), effective July 2, 2020
3.3	001-38086 Form 8-K (filed on October 15, 2021)	3.1	—	Series A Preferred Stock Certificate of Designation, filed with the Secretary of State of Delaware on October 14, 2021
3.4	001-38086 Form 8-K (filed on December 13, 2021)	3.1	—	Series B Preferred Stock Certificate of Designation, filed with the Secretary of State of Delaware on December 9, 2021
3.5	001-38086 Form 8-K (filed on January 4, 2024)	3.1	—	Series C Preferred Stock Certificate of Designation filed with the Secretary of State of Delaware on December 29, 2023
(3(ii))	**By-laws**			
3.6	001-38086 Form 8-K (filed on November 5, 2024)	3.5	—	Amended and Restated Bylaws of Vistra Corp., effective October 30, 2024
(4)	**Instruments Defining the Rights of Security Holders, Including Indentures**			
4.1	001-38086 Form 8-K (filed on August 23, 2018)	4.1	—	Indenture for 5.500% Senior Note due 2026, dated as of August 22, 2018, among Vistra Operations Company LLC, as issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee
4.2	001-38086 Form 8-K (filed on August 23, 2018)	4.2	—	Form of Rule 144A Global Security for 5.500% Senior Note due 2026 (included in Exhibit 4.1)

Exhibits	Previously Filed With File Number*	As Exhibit		
4.3	001-38086 Form 8-K (filed on August 23, 2018)	4.3	—	Form of Regulation S Global Security for 5.500% Senior Note due 2026 (included in Exhibit 4.1)
4.4	001-38086 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.5	—	First Supplemental Indenture for the 5.500% Senior Notes due 2026, dated August 30, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.5	001-38086 Form 10-K (Year ended December 31, 2019) (filed on February 28, 2020)	4.36	—	Second Supplemental Indenture for the 5.500% Senior Notes due 2026, dated October 25, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.6	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.5	—	Third Supplemental Indenture for the 5.500% Senior Notes due 2026, dated January 31, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.7	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.6	—	Fourth Supplemental Indenture for the 5.500% Senior Notes due 2026, dated March 26, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.8	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.8	—	Fifth Supplemental Indenture for the 5.500% Senior Notes due 2026, dated October 7, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.9	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.9	—	Sixth Supplemental Indenture for the 5.500% Senior Notes due 2026, dated January 8, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.10	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.3	—	Seventh Supplemental Indenture for the 5.500% Senior Notes due 2026, dated July 29, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.11	001-38086 Form 10-K (Year ended December 31, 2021) (filed on February 25, 2022)	4.11	—	Eighth Supplemental Indenture for the 5.500% Senior Notes due 2026, dated December 28, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.12	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	4.12	—	Ninth Supplemental Indenture for the 5.500% Senior Notes due 2026, dated December 15, 2022, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.13	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	4.1	—	Tenth Supplemental Indenture for the 5.500% Senior Notes due 2026, dated July 31, 2023, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.14	**		—	Eleventh Supplemental Indenture for the 5.500% Senior Notes due 2026, dated October 20, 2023, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.15	001-38086 Form 10-Q (Quarter ended March 31, 2024) (filed on May 10, 2024)	4.6	—	Twelfth Supplemental Indenture for 5.500% Senior Notes due 2026, dated March 29, 2024, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.16	001-38086 Form 8-K (filed on February 6, 2019)	4.1	—	Indenture for 5.625% Senior Note due 2027, dated as of February 6, 2019, among Vistra Operations Company LLC, as issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee

Exhibits	Previously Filed With File Number*	As Exhibit		
4.17	001-38086 Form 8-K (filed on February 6, 2019)	4.2	—	Form of Rule 144A Global Security for 5.625% Senior Note due 2027 (included in Exhibit 4.1)
4.18	001-38086 Form 8-K (filed on February 6, 2019)	4.3	—	Form of Regulation S Global Security for 5.625% Senior Note due 2027 (included in Exhibit 4.1)
4.19	001-38086 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.6	—	First Supplemental Indenture for the 5.625% Senior Notes due 2027, dated August 30, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.20	001-38086 Form 10-K (Year ended December 31, 2019) (filed on February 28, 2020)	4.41	—	Second Supplemental Indenture for the 5.625% Senior Notes due 2027, dated October 25, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.21	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.7	—	Third Supplemental Indenture for the 5.625% Senior Notes due 2027, dated January 31, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.22	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.8	—	Fourth Supplemental Indenture for the 5.625% Senior Notes due 2027, dated March 26, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.23	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.17	—	Fifth Supplemental Indenture for the 5.625% Senior Notes due 2027, dated October 7, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.24	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.18	—	Sixth Supplemental Indenture for the 5.625% Senior Notes due 2027, dated January 8, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.25	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.4	—	Seventh Supplemental Indenture for the 5.625% Senior Notes due 2027, dated July 29, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.26	001-38086 Form 10-K (Year ended December 31, 2021) (filed on February 25, 2022)	4.22	—	Eighth Supplemental Indenture for the 5.625% Senior Notes due 2027, dated December 28, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.27	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	4.24	—	Ninth Supplemental Indenture for the 5.625% Senior Notes due 2027, dated December 15, 2022, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.28	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	4.2	—	Tenth Supplemental Indenture for the 5.625% Senior Notes due 2027, dated July 31, 2023, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.29	**		—	Eleventh Supplemental Indenture for the 5.625% Senior Notes due 2027, dated October 20, 2023, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.30	001-38086 Form 10-Q (Quarter ended March 31, 2024) (filed on May 10, 2024)	4.7	—	Twelfth Supplemental Indenture for 5.625% Senior Notes due 2027, dated March 29, 2024, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee

Exhibits	Previously Filed With File Number*	As Exhibit		
4.31	001-38086 Form 8-K (filed on June 24, 2019)	4.1	—	Indenture for 5.00% Senior Notes due 2027, dated as of June 21, 2019, among Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee
4.32	001-38086 Form 8-K (filed on June 24, 2019)	4.2	—	Form of Rule 144A Global Security for 5.00% Senior Notes due 2027 (included in Exhibit 4.1)
4.33	001-38086 Form 8-K (filed on June 24, 2019)	4.3	—	Form of Regulation S Global Security for 5.00% Senior Notes due 2027 (included in Exhibit 4.1)
4.34	001-38086 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.7	—	First Supplemental Indenture for the 5.000% Senior Notes due 2027, dated August 30, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.35	001-38086 Form 10-K (Year ended December 31, 2019) (filed on February 28, 2020)	4.46	—	Second Supplemental Indenture for the 5.000% Senior Notes due 2027, dated October 25, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.36	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.9	—	Third Supplemental Indenture for the 5.000% Senior Notes due 2027, dated January 31, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.37	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.10	—	Fourth Supplemental Indenture for the 5.000% Senior Notes due 2027, dated March 26, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.38	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.26	—	Fifth Supplemental Indenture for the 5.000% Senior Notes due 2027, dated October 7, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.39	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.27	—	Sixth Supplemental Indenture for the 5.000% Senior Notes due 2027, dated January 8, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.40	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.5	—	Seventh Supplemental Indenture for the 5.000% Senior Notes due 2027, dated July 29, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.41	001-38086 Form 10-K (Year ended December 31, 2021) (filed on February 25, 2022)	4.33	—	Eighth Supplemental Indenture for the 5.000% Senior Notes due 2027, dated December 28, 2021, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.42	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	4.36	—	Ninth Supplemental Indenture for the 5.000% Senior Notes due 2027, dated December 15, 2022, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.43	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	4.3	—	Tenth Supplemental Indenture for the 5.000% Senior Notes due 2027, dated July 31, 2023, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.44	**		—	Eleventh Supplemental Indenture for the 5.000% Senior Notes due 2027, dated October 20, 2023, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee

Exhibits	Previously Filed With File Number*	As Exhibit		
4.45	001-38086 Form 10-Q (Quarter ended March 31, 2024) (filed on May 10, 2024)	4.8	—	Twelfth Supplemental Indenture for 5.00% Senior Notes due 2027, dated March 29, 2024, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.46	001-38086 Form 8-K (filed on June 17, 2019)	4.1	—	Indenture, dated as of June 11, 2019, between Vistra Operations Company LLC, as Issuer, and Wilmington Trust, National Association, as Trustee
4.47	001-38086 Form 8-K (filed on June 17, 2019)	4.2	—	Supplemental Indenture for 3.55% Senior Secured Notes due 2024 and 4.30% Senior Secured Notes Due 2029, dated as of June 11, 2019, among Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee
4.48	001-38086 Form 8-K (filed on June 17, 2019)	4.4	—	Form of Rule 144A Global Security for 4.30% Senior Notes due 2029 (included in Exhibit 4.2)
4.49	001-38086 Form 8-K (filed on June 17, 2019)	4.6	—	Form of Regulation S Global Security for 4.30% Senior Notes due 2029 (included in Exhibit 4.2)
4.50	001-38086 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.8	—	Second Supplemental Indenture for 3.55% Senior Secured Notes due 2024 and 4.30% Senior Secured Notes due 2029, dated as of August 30, 2019, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.51	001-38086 Form 8-K (filed on November 21, 2019)	4.1	—	Third Supplemental Indenture for 3.55% Senior Secured Notes due 2024 and 4.30% Senior Secured Notes due 2029, dated as of October 25, 2019, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, Subsidiary Guarantors and the Trustee
4.52	001-38086 Form 8-K (filed on November 21, 2019)	4.2	—	Fourth Supplemental Indenture, dated as of November 15, 2019, among Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee
4.53	001-38086 Form 8-K (filed on November 21, 2019)	4.3	—	Form of Rule 144A Global Security for 3.70% Senior Note due 2027 (included in Exhibit 4.2)
4.54	001-38086 Form 8-K (filed on November 21, 2019)	4.4	—	Form of Regulation S Global Security for 3.70% Senior Note due 2027 (included in Exhibit 4.2)
4.55	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.11	—	Fifth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of January 31, 2020, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.56	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.12	—	Sixth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of March 26, 2020, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.57	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.41	—	Seventh Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of October 7, 2020, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee

Exhibits	Previously Filed With File Number*	As Exhibit		
4.58	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.42	—	Eighth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of January 8, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.59	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.6	—	Ninth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of July 29, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.60	001-38086 Form 10-K (Year ended December 31, 2021) (filed on February 25, 2022)	4.50	—	Tenth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of December 28, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.61	001-38086 Form 8-K (filed on May 16, 2022)	4.1	—	Eleventh Supplemental Indenture for 4.875% Senior Secured Notes due 2024 and 5.125% Senior Secured Notes due 2025, dated as of May 13, 2022, among Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors and the Trustee
4.62	001-38086 Form 8-K (filed on May 16, 2022)	4.4	—	Form of Rule 144A Global Security for 5.125% Senior Note due 2025 (included in Exhibit 4.1)
4.63	001-38086 Form 8-K (filed on May 16, 2022)	4.5	—	Form of Regulation S Global Security for 5.125% Senior Note due 2025 (included in Exhibit 4.1)
4.64	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	4.55	—	Twelfth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027, 4.30% Senior Secured Notes due 2029, 4.875% Senior Secured Notes due 2024 and 5.125% Senior Secured Notes due 2025, dated as of December 15, 2022, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.65	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	4.4	—	Thirteenth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027, 4.30% Senior Secured Notes due 2029, 4.875% Senior Secured Notes due 2024 and 5.125% Senior Secured Notes due 2025, dated as of July 31, 2023, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.66	001-38086 Form 8-K (filed on October 2, 2023)	4.1	—	Fourteenth Supplemental Indenture for the 6.950% Senior Secured Notes due 2033, dated as of September 26, 2023, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.67	**		—	Fifteenth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 4.30% Senior Secured Notes due 2029, 3.70% Senior Secured Notes due 2027, 4.875% Senior Secured Notes due 2024, 5.125% Senior Secured Notes due 2025 and 6.950% Senior Secured Notes due 2033, dated October 20, 2023, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.68	001-38086 Form 10-Q (Quarter ended March 31, 2024) (filed on May 10, 2024)	4.9	—	Sixteenth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 4.30% Senior Secured Notes due 2029, 3.70% Senior Secured Notes due 2027, 4.875% Senior Secured Notes due 2024, 5.125% Senior Secured Notes due 2025 and 6.950% Senior Secured Notes due 2033, dated March 29, 2024, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee

Exhibits	Previously Filed With File Number*	As Exhibit		
4.69	001-38086 Form 8-K (filed on April 18, 2024)	4.1	—	Seventeenth Supplemental Indenture, dated as of April 12, 2024, between Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors, and Wilmington Trust, National Association, as Trustee
4.70	001-38086 Form 8-K (filed on December 9, 2024)	4.1	—	Eighteenth Supplemental Indenture, dated as of December 4, 2024, between Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors, and Wilmington Trust, National Association, as Trustee
4.71	001-38086 Form 8-K (filed on December 9, 2024)	4.2	—	Form of Rule 144A Global Security for 5.050% Senior Secured Note due 2026 (included in Exhibit 4.1)
4.72	001-38086 Form 8-K (filed on December 9, 2024)	4.3	—	Form of Rule 144A Global Security for 5.700% Senior Secured Note due 2034 (included in Exhibit 4.1)
4.73	001-38086 Form 8-K (filed on December 9, 2024)	4.4	—	Form of Regulation S Global Security for 5.050% Senior Secured Note due 2026 (included in Exhibit 4.1)
4.74	001-38086 Form 8-K (filed on December 9, 2024)	4.5	—	Form of Regulation S Global Security for 5.700% Senior Secured Note due 2034 (included in Exhibit 4.1)
4.75	001-38086 Form 8-K (filed on April 18, 2024)	4.2	—	Indenture, dated as of April 12, 2024, between Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors, and Wilmington Trust, National Association, as Trustee
4.76	001-38086 Form 8-K (filed on April 18, 2024)	4.3	—	Form of Rule 144A Global Security for 6.000% Senior Secured Note due 2034 (included in Exhibit 4.1)
4.77	001-38086 Form 8-K (filed on April 18, 2024)	4.4	—	Form of Rule 144A Global Security for 6.875% Senior Note due 2032 (included in Exhibit 4.2)
4.78	001-38086 Form 8-K (filed on April 18, 2024)	4.5	—	Form of Regulation S Global Security for 6.000% Senior Secured Note due 2034 (included in Exhibit 4.1)
4.79	001-38086 Form 8-K (filed on April 18, 2024)	4.6	—	Form of Regulation S Global Security for 6.875% Senior Note due 2032 (included in Exhibit 4.2)
4.80	001-38086 Form 8-K (filed on October 2, 2023)	4.2	—	Indenture for the 7.750% Senior Unsecured Notes due 2031, dated as of September 26, 2023, by and among Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors and the Trustee
4.81	001-38086 Form 8-K (filed on October 2, 2023)	4.3	—	Form of Rule 144A Global Security for 6.950% Senior Secured Note due 2033 (included in Exhibit 4.1)
4.82	001-38086 Form 8-K (filed on October 2, 2023)	4.4	—	Form of Regulation S Global Security for 6.950% Senior Secured Note due 2033 (included in Exhibit 4.1)
4.83	001-38086 Form 8-K (filed on October 2, 2023)	4.5	—	Form of Rule 144A Global Security for 7.750% Senior Unsecured Note due 2031 (included in Exhibit 4.2)

Exhibits	Previously Filed With File Number*	As Exhibit		
4.84	001-38086 Form 8-K (filed on October 2, 2023)	4.6	—	Form of Regulation S Global Security for 7.750% Senior Unsecured Note due 2031 (included in Exhibit 4.2)
4.85	**		—	First Supplemental Indenture for 7.750% Senior Secured Notes due 2031, dated October 20, 2023, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.86	001-38086 Form 10-Q (Quarter ended March 31, 2024) (filed on May 10, 2024)	4.3	—	Second Supplemental Indenture for 7.750% Senior Secured Notes due 2031, dated March 29, 2024, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.87	001-38086 Form 8-K (filed on May 11, 2021)	4.1	—	Indenture for 4.375% Senior Notes due 2029, dated as of May 10, 2021, between Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors, and Wilmington Trust, National Association, as Trustee
4.88	001-38086 Form 8-K (filed on May 11, 2021)	4.2	—	Form of Rule 144A Global Security for 4.375% Senior Notes due 2029 (included in Exhibit 4.1)
4.89	001-38086 Form 8-K (filed on May 11, 2021)	4.3	—	Form of Regulation S Global Security for 4.375% Senior Notes due 2029 (included in Exhibit 4.1)
4.90	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.7	—	First Supplemental Indenture for the 4.375% Senior Notes due 2029, dated July 29, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.91	001-38086 Form 10-K (Year ended December 31, 2021) (filed on February 25, 2022)	4.55	—	Second Supplemental Indenture for the 4.375% Senior Notes due 2029, dated December 28, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.92	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	4.65	—	Third Supplemental Indenture for the 4.375% Senior Notes due 2029, dated December 15, 2022, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.93	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	4.5	—	Fourth Supplemental Indenture for the 4.375% Senior Notes due 2029, dated July 31, 2023, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.94	**		—	Fifth Supplemental Indenture for 4.375% Senior Notes due 2029, dated October 20, 2023, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.95	001-38086 Form 10-Q (Quarter ended March 31, 2024) (filed on May 10, 2024)	4.5	—	Sixth Supplemental Indenture for 4.375% Senior Notes due 2029, dated March 29, 2024, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.96	001-38086 Form 10-Q (Quarter ended March 31, 2024) (filed on May 10, 2024)	4.16	—	First Supplemental Indenture, dated as of June 15, 2009, under the Open-End Mortgage, General Mortgage Indenture and Deed of Trust, dated as of June 1, 2009
4.97	001-38086 Form 10-Q (Quarter ended March 31, 2024) (filed on May 10, 2024)	4.17	—	Second Supplemental Indenture, dated as of June 30, 2009, under the Open-End Mortgage, General Mortgage Indenture and Deed of Trust, dated as of June 1, 2009

Exhibits	Previously Filed With File Number*	As Exhibit		
4.98	001-38086 Form 10-Q (Quarter ended March 31, 2024) (filed on May 10, 2024)	4.18	—	Fifth Supplemental Indenture, dated as of August 15, 2016, under the Open-End Mortgage, General Mortgage Indenture and Deed of Trust, dated as of June 1, 2009
4.99	001-38086 Form 10-Q (Quarter ended March 31, 2024) (filed on May 10, 2024)	4.19	—	Eighth Supplemental Indenture, dated as of August 15, 2016, under the Open-End Mortgage, General Mortgage Indenture and Deed of Trust, dated as of June 19, 2008
4.100	001-38086 Form 10-Q (Quarter ended March 31, 2024) (filed on May 10, 2024)	4.20	—	Open-End Mortgage, General Mortgage Indenture and Deed of Trust, dated as of June 1, 2009
4.101	001-38086 Form 10-Q (Quarter ended March 31, 2024) (filed on May 10, 2024)	4.21	—	Open-End Mortgage, General Mortgage Indenture and Deed of Trust, dated as of June 19, 2008
4.102	001-38086 Form 8-K (filed on August 23, 2018)	4.7	—	Purchase and Sale Agreement dated as of August 21, 2018, between TXU Energy Retail Company LLC as originator, and TXU Energy Receivables Company LLC, as purchaser
4.103	001-38086 Form 8-K (filed on August 23, 2018)	4.8	—	Receivable Purchase Agreement dated as of August 21, 2018, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein and Credit Agricole Corporate and Investment Bank, as administrator
4.104	001-38086 Form 8-K (filed on April 5, 2019)	4.1	—	First Amendment to Purchase and Sale Agreement, dated as of April 1, 2019, among TXU Energy Retail Company LLC, Dynegy Energy Services, LLC, and Dynegy Energy Services (East), LLC, each as an originator, and TXU Energy Receivables Company LLC, as purchaser
4.105	001-38086 Form 10-Q (Quarter ended June 30, 2019) (filed on August 2, 2019)	4.12	—	Second Amendment to Purchase and Sale Agreement, dated as of June 3, 2019, among TXU Energy Retail Company LLC, Dynegy Energy Services, LLC, and Dynegy Energy Services (East), LLC, each as an originator, and TXU Energy Receivables Company LLC, as purchaser
4.106	001-38086 Form 8-K (filed on July 19, 2019)	4.1	—	Third Amendment to Purchase and Sale Agreement, dated as of July 15, 2019, among TXU Energy Retail Company LLC, Dynegy Energy Services, LLC, and Dynegy Energy Services (East), LLC, each as an originator, and TXU Energy Receivables Company LLC, as purchaser
4.107	001-38086 Form 8-K (filed on October 16, 2020)	4.1	—	Fourth Amendment to Purchase and Sale Agreement, dated as of October 9, 2020, among TXU Energy Retail Company LLC, as an originator and servicer, the other originators named therein, and TXU Energy Receivables Company LLC, as purchaser
4.108	001-38086 Form 8-K (filed on December 28, 2020)	4.1	—	Fifth Amendment to Purchase and Sale Agreement, dated as of December 21, 2020, among TXU Energy Retail Company LLC, certain originators named therein, and TXU Energy Receivables Company LLC, as purchaser
4.109	001-38086 Form of 8-K (filed on April 9, 2024)	4.2	—	Sixth Amendment to Purchase and Sale Agreement, dated as of April 8, 2024, among TXU Receivables, as buyer, TXU Retail, as servicer, certain originators named therein and Credit Agricole Corporate and Investment Bank, as administrator

Exhibits	Previously Filed With File Number*	As Exhibit		
4.110	001-38086 Form 8-K (filed on April 5, 2019)	4.2	—	First Amendment to Receivables Purchase Agreement, dated as of April 1, 2019, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein and Credit Agricole Corporate and Investment Bank, as administrator
4.111	001-38086 Form 10-Q (Quarter ended June 30, 2019) (filed on August 2, 2019)	4.13	—	Second Amendment to Receivables Purchase Agreement, dated as of June 3, 2019, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein and Credit Agricole Corporate and Investment Bank, as administrator
4.112	001-38086 Form 8-K (filed on July 19, 2019)	4.2	—	Third Amendment to Receivables Purchase Agreement, dated as of July 15, 2019, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein and Credit Agricole Corporate and Investment Bank, as administrator
4.113	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	4.76	—	Fourth Amendment to Receivables Purchase Agreement, dated as of November 15, 2019, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein and Credit Agricole Corporate and Investment Bank, as administrator
4.114	001-38086 Form 8-K (filed on July 16, 2020)	4.1	—	Fifth Amendment to Receivables Purchase Agreement, dated as of July 13, 2020, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein and Credit Agricole Corporate and Investment Bank, as administrator
4.115	001-38086 Form 8-K (filed on October 16, 2020)	4.2	—	Sixth Amendment to Receivables Purchase Agreement, dated as of October 9, 2020, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein, and Credit Agricole Corporate and Investment Bank, as administrator
4.116	001-38086 Form 8-K (filed on December 28, 2020)	4.2	—	Seventh Amendment to Receivables Purchase Agreement, dated as of December 21, 2020, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein, and Credit Agricole Corporate and Investment Bank, as administrator
4.117	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.56	—	Eighth Amendment to Receivables Purchase Agreement, dated as of February 19, 2020, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein, and Credit Agricole Corporate and Investment Bank, as administrator
4.118	001-38086 Form 10-Q (Quarter ended March 31, 2021) (filed on May 4, 2021)	4.6	—	Ninth Amendment to Receivables Purchase Agreement, dated as of March 26, 2021, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein, and Credit Agricole Corporate and Investment Bank, as administrator

Exhibits	Previously Filed With File Number*	As Exhibit		
4.119	001-38086 Form 8-K (filed on July 15, 2021)	4.1	—	Tenth Amendment to Receivables Purchase Agreement, dated as of July 9, 2021, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein, and Credit Agricole Corporate and Investment Bank, as administrator
4.120	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.2	—	Eleventh Amendment to Receivables Purchase Agreement, dated as of July 16, 2021, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein, and Credit Agricole Corporate and Investment Bank, as administrator
4.121	001-38086 Form of 8-K (filed on July 15, 2022)	4.1	—	Twelfth Amendment to Receivables Purchase Agreement, dated as of July 11, 2022, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein, and Credit Agricole Corporate and Investment Bank, as administrator
4.122	001-38086 Form of 8-K (filed on July 17, 2023)	4.1	—	Thirteenth Amendment to Receivables Purchase Agreement, dated as of July 11, 2023, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein and Credit Agricole Corporate and Investment Bank, as administrator
4.123	001-38086 Form of 8-K (filed on April 9, 2024)	4.1	—	Fourteenth Amendment to Receivables Purchase Agreement, dated as of April 8, 2024, among TXU Receivables, as seller, TXU Retail, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein and Credit Agricole Corporate and Investment Bank, as administrator
4.124	001-38086 Form of 8-K (filed on July 12, 2024)	4.1	—	Fifteenth Amendment to Receivables Purchase Agreement, dated as of July 11, 2024, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein and Credit Agricole Corporate and Investment Bank, as administrator
4.125	001-38086 Form of 8-K (filed on June 22, 2023)	4.1	—	Facility Agreement, dated June 15, 2023, among Palomino Funding Trust I, Vistra Operations Company LLC, the subsidiary guarantors party thereto and Bank of New York Mellon Trust Company, N.A., as senior secured notes trustee
4.126	001-38086 Form of 8-K (filed on June 22, 2023)	4.2	—	Amended and Restated Declaration of Trust of Palomino Funding Trust I, dated June 15, 2023, among Vistra Operations Company LLC, as depositor, The Bank of New York Mellon Trust Company, N.A., as trustee, BNY Mellon Trust of Delaware, as Delaware trustee, and Vistra Operations Company LLC, solely for the purposes of Sections 5.10(b) and (f), Sections 5.17(b), (d), (e) and (f) and Section 10.4(c)
4.127	001-38086 Form of 8-K (filed on June 22, 2023)	4.3	—	Indenture, dated June 15, 2023, between Vistra Operations Company LLC, as issuer, and The Bank of New York Mellon Trust Company, N.A., as trustee
4.128	001-38086 Form of 8-K (filed on June 22, 2023)	4.4	—	Supplemental Indenture, dated June 15, 2023, between Vistra Operations Company LLC, as issuer, the subsidiary guarantors party thereto and The Bank of New York Mellon Trust Company, N.A., as trustee
4.129	001-38086 Form of 8-K (filed on June 22, 2023)	4.5	—	Form of 7.233% Senior Secured Notes due 2028 (included in Exhibit 4.4)

Exhibits	Previously Filed With File Number*	As Exhibit		
4.130	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	4.6	—	Second Supplemental Indenture for the 7.233% Senior Secured Notes due 2028, dated August 3, 2023, among Vistra Operations Company LLC, as Issuer, the subsidiary guarantors party thereto and the Bank of New York Mellon Trust Company, N.A., as trustee
4.131	**		—	Third Supplemental Indenture for 7.233% Senior Secured Notes due 2028, dated October 20, 2023, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Bank of New York Mellon Trust Company, N.A., as trustee
4.132	001-38086 Form 10-Q (Quarter ended March 31, 2024) (filed on May 10, 2024)	4.4	—	Fourth Supplemental Indenture for 7.233% Senior Secured Notes due 2028, dated March 29, 2024, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.133	333-215288 Form S-1 (filed December 23, 2016)	4.1	—	Registration Rights Agreement, by and among TCEH Corp. (now known as Vistra Corp.) and the Holders party thereto, dated as of October 3, 2016
4.134	**		—	Description of Capital Stock
(10)	**Material Contracts**			
	Management Contracts; Compensatory Plans, Contracts and Arrangements			
10.1	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.6	—	2016 Omnibus Incentive Plan
10.2	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.7	—	Form of Option Award Agreement (Management) for 2016 Omnibus Incentive Plan (pre-2021 awards)
10.3	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.5	—	Form of Option Award Agreement (Management) for 2016 Omnibus Incentive Plan
10.4	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.6	—	Form of Restricted Stock Unit Award Agreement (Management) for 2016 Omnibus Incentive Plan (2021)
10.5	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.7	—	Form of Restricted Stock Unit Award Agreement (Director) for 2016 Omnibus Incentive Plan
10.6	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.8	—	Form of Performance Stock Unit Award Agreement for 2016 Omnibus Incentive Plan (2021)
10.7	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.9	—	Vistra Corp. Executive Annual Incentive Plan
10.8	**		—	Form of Restricted Stock Unit Award Agreement (Management), for 2016 Omnibus Incentive Plan, effective as of January 1, 2025
10.9	**		—	Form of Performance Stock Unit Award Agreement (Management) for 2016 Omnibus Incentive Plan, effective as of January 1, 2025
10.10	**		—	Amended and Restated Vistra Annual Incentive Plan, effective as of January 1, 2025

Exhibits	Previously Filed With File Number*	As Exhibit		
10.11	001-38086 Form 8-K (filed on May 23, 2019)	10.1	—	Amended and Restated 2016 Omnibus Incentive Plan, effective as of May 20, 2019
10.12	001-38086 Form of 8-K (filed on May 6, 2024)	10.1	—	Amended and Restated 2016 Omnibus Incentive Plan effective as of May 1, 2024
10.13	001-33443 Form10-K (Year ended December 31, 2018) (filed on February 28, 2019)	10.7	—	Vistra Equity Deferred Compensation Plan for Certain Directors, effective as of January 1, 2019
10.14	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.13	—	Amendment No. 1 to the Vistra Equity Deferred Compensation Plan, dated effective as of February 24, 2021
10.15	001-38086 Form 10-K (Year ended December 31, 2023) (filed on February 29, 2024)	10.15	—	Second Amended and Restated Employment Agreement, dated March 20, 2022, between James A. Burke and Vistra Corp.
10.16	001-38086 Form 10-K (Year ended December 31, 2023) (filed on February 29, 2024)	10.16	—	Employment Agreement, dated as of July 20, 2022, between Kristopher E. Moldovan, Vistra Corp. and Vistra Corporate Services Company
10.17	001-38086 Form 10-K (Year ended December 31, 2023) (filed on February 29, 2024)	10.17	—	Amended and Restated Employment Agreement, dated as of May 5, 2022, between Stephanie Zapata Moore, Vistra Corp. and Vistra Corporate Services Company
10.18	001-38086 Form 10-K (Year ended December 31, 2023) (filed on February 29, 2024)	10.18	—	Amended and Restated Employment Agreement, dated as of May 5, 2022, between Carrie Lee Kirby, Vistra Corp. and Vistra Corporate Services Company
10.19	001-38086 Form 10-K (Year ended December 31, 2023) (filed on February 29, 2024)	10.19	—	Amended and Restated Employment Agreement, dated as of May 5, 2022, between Scott A. Hudson, Vistra Corp. and Vistra Corporate Services Company
10.20	001-38086 Form 10-K (Year ended December 31, 2023) (filed on February 29, 2024)	10.20	—	Amended and Restated Employment Agreement, dated as of May 5, 2022, between Stephen J. Muscato, Vistra Corp. and Vistra Corporate Services Company
10.21	001-38086 Form 10-K (Year ended December 31, 2023) (filed on February 29, 2024)	10.21	—	Employment Agreement, dated as of August 23, 2022, between Stacey Doré, Vistra Corp. and Vistra Corporate Services Company
10.22	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	10.22	—	Form of indemnification agreement with directors and officers
	Credit Agreements and Related Agreements			
10.23	333-215288 Form S-1 (filed December 23, 2016)	10.1	—	Credit Agreement, dated as of October 3, 2016
10.24	333-215288 Form S-1 (filed December 23, 2016)	10.2	—	Amendment to Credit Agreement, dated December 14, 2016, by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.

Exhibits	Previously Filed With File Number*	As Exhibit		
10.25	333-215288 Amendment No. 1 to Form S-1 (filed February 14, 2017)	10.3	—	Second Amendment to Credit Agreement, dated February 1, 2017, by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.26	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.4	—	Third Amendment to Credit Agreement, dated February 28, 2017, by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.27	001-38086 Form 8-K (filed August 17, 2017)	10.1	—	Fourth Amendment to Credit Agreement, dated as of August 17, 2017 (effective August 17, 2017), by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.28	001-38086 Form 8-K (filed December 14, 2017)	10.1	—	Fifth Amendment to Credit Agreement, dated as of December 14, 2017 (effective December 14, 2017), by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.29	001-38086 Form 8-K (filed February 22, 2018)	10.1	—	Sixth Amendment to Credit Agreement, dated as of February 20, 2018 (effective February 20, 2018), by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.30	001-38086 Form 8-K (filed June 15, 2018)	10.1	—	Seventh Amendment to Credit Agreement, dated as of June 14, 2018, by and among Vistra Operations Company LLC, Vistra Intermediate Company LLC, the other Credit Parties party thereto, Credit Suisse and Citibank, N.A. as the 2018 Incremental Term Loan Lenders, the various other Lenders party thereto, Credit Suisse as Successor Administrative Agent and as Successor Collateral Agent, and Delaware Trust Company, as Collateral Trustee.
10.31	001-38086 Form 8-K (filed April 4, 2019)	10.4	—	Eighth Amendment to Credit Agreement, dated March 29, 2019, by and among Vistra Operations Company LLC, Vistra Intermediate Company LLC, the other Credit Parties (as defined in the Vistra Operations Credit Agreement) party thereto, Bank of Montreal, Chicago Branch, as new Revolving Loan Lender, Revolving Letter of Credit Issuer and Joint Lead Arranger, the various other Lenders and Letter of Credit Issuers party thereto, and Credit Suisse as Administrative Agent and Collateral Agent
10.32	001-38086 Form 8-K (filed May 29, 2019)	10.1	—	Ninth Amendment to Credit Agreement, dated May 29, 2019, by and among Vistra Operations Company LLC, Vistra Intermediate Company LLC, the other Credit Parties (as defined in the Vistra Operations Credit Agreement) party thereto, Sun Trust Bank, as incremental Revolving Loan Lender, and Credit Suisse AG, Cayman Island Branch, as Administrative Agent and Collateral Agent
10.33	001-38086 Form 8-K (filed on November 21, 2019)	10.1	—	Tenth Amendment to the Credit Agreement, dated November 15, 2019, by and among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), the other Credit Parties (as defined in the Credit Agreement) party thereto, the other Credit Parties (as defined in the Credit Agreement) party thereto, Credit Suisse AG, Cayman Islands Branch (as the 2019 Incremental Term Loan Lender and as Administrative Agent and as Collateral Agent), and the other Lenders party thereto

Exhibits	Previously Filed With File Number*	As Exhibit		
10.34	001-38086 Form 8-K (filed on May 5, 2022)	10.1	—	Eleventh Amendment to the Credit Agreement, dated April 29, 2022, by and among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), the other Credit Parties (as defined in the Credit Agreement) party thereto, the other Credit Parties (as defined in the Credit Agreement) party thereto, the financial institutions providing 2022 New Revolving Credit Commitments (as defined in the Credit Agreement), the Revolving Credit Lenders providing 2022 Extended Revolving Credit Commitments (as defined in the Credit Agreement), the Revolving Letter of Credit Issuers (as defined in the Credit Agreement) party thereto, and Credit Suisse AG, Cayman Islands Branch (as Administrative Agent and as Collateral Agent)
10.35	001-38086 Form 10-Q (Quarter ended September 30, 2022) (filed on November 4, 2022)	10.3	—	Twelfth Amendment to the Credit Agreement, dated July 18, 2022, by and among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), the other Credit Parties (as defined in the Credit Agreement) party thereto, financial institutions, Revolving Credit Lenders, and Revolving Letter of Credit Issuers (in each case as defined in the Credit Agreement) party thereto, and Credit Suisse AG, Cayman Islands Branch (as Administrative Agent and as Collateral Agent)
10.36	001-38086 Form 10-Q (Quarter ended June 30, 2023) (filed on August 9, 2023)	10.1	—	Thirteenth Amendment to the Credit Agreement, dated April 28, 2023, by and among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), the other Credit Parties (as defined in the Credit Agreement) party thereto, financial institutions, Revolving Credit Lenders, and Revolving Letter of Credit Issuers (in each case as defined in the Credit Agreement) party thereto, and Credit Suisse AG, Cayman Islands Branch (as Administrative Agent and as Collateral Agent)
10.37	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	10.1	—	Fourteenth Amendment to the Credit Agreement, dated September 26, 2023, by and among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), the other Credit Parties (as defined in the Credit Agreement) party thereto, financial institutions, Revolving Credit Lenders, and Revolving Letter of Credit Issuers (in each case as defined in the Credit Agreement) party thereto, and Credit Suisse AG, Cayman Islands Branch (as Administrative Agent and as Collateral Agent)
10.38	001-38086 Form 8-K (filed on December 26, 2023)	10.1	—	Fifteenth Amendment to the Credit Agreement, dated December 20, 2023, by and among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), the 2023 Incremental Term Loan Lender, the other Credit Parties (as defined in the Credit Agreement) party thereto, the other lenders party thereto, and Credit Suisse AG, Cayman Islands Branch (as Administrative Agent and as Collateral Agent)
10.39	001-38086 Form 10-Q (Quarter ended September 30, 2024) (filed on November 8, 2024)	10.6	—	Sixteenth Amendment to the Credit Agreement, dated October 11, 2024, by and among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), the guarantors party thereto, the revolving credit lenders and revolving letter of credit issuers party thereto, and Citibank, N.A. (as Administrative Agent and as Collateral Agent)
10.40	001-38086 Form 8-K (filed on December 16, 2024)	10.1	—	Seventeenth Amendment to Credit Agreement, dated December 10, 2024, by and among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), the other Credit Parties (as defined in the Credit Agreement) party thereto, the lenders party thereto, and Citibank, N.A. (as Administrative Agent and Collateral Agent)
10.41	001-38086 Form 8-K (filed on April 9, 2018)	10.10	—	Assumption Agreement, dated as of April 9, 2018, between Vistra Energy Corp. (now known as Vistra Corp.) (as successor by merger to Dynegy Inc.), and Credit Suisse AG, Cayman Islands Branch, as Administrative Agent and as Collateral Trustee.

Exhibits	Previously Filed With File Number*	As Exhibit		
10.42	001-38086 Form 8-K (filed on April 9, 2018)	10.11	—	Guarantee and Collateral Agreement, dated as of April 23, 2013, among Dynegy Inc., the subsidiaries of the borrower from time to time party thereto and Credit Suisse AG, Cayman Islands Branch, as Collateral Trustee (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K of Dynegy Inc. filed on April 24, 2013).
10.43	001-38086 Form 8-K (filed on April 9, 2018)	10.12	—	Joinder, dated as of April 9, 2018, among Vistra Energy Corp. (now known as Vistra Corp.), the subsidiary guarantors party thereto and Credit Suisse AG, Cayman Islands Branch, as Collateral Trustee.
10.44	001-38086 Form 8-K (filed on April 9, 2018)	10.13	—	Collateral Trust and Intercreditor Agreement, dated as of April 23, 2013 among Dynegy, the Subsidiary Guarantors (as defined therein), Credit Suisse AG, Cayman Islands Branch and each person party thereto from time to time (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K of Dynegy Inc. filed on April 24, 2013).
10.45	001-38086 Form 10-K (Year ended December 31, 2021) (filed on February 25, 2022)	10.63	—	Credit Agreement, dated as of February 4, 2022, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
10.46	001-38086 Form 10-Q (Quarter ended June 30, 2022) (filed on August 5, 2022)	10.3	—	First Amendment to Credit Agreement, dated as of May 5, 2022, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
10.47	001-38086 Form 10-Q (Quarter ended June 30, 2022) (filed on August 5, 2022)	10.4	—	Second Amendment to Credit Agreement, dated as of May 26, 2022, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
10.48	001-38086 Form 10-Q (Quarter ended June 30, 2022) (filed on August 5, 2022)	10.5	—	Third Amendment to Credit Agreement, dated as of June 8, 2022, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
10.49	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	10.72	—	Fourth Amendment to Credit Agreement, dated as of October 5, 2022, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
10.50	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	10.73	—	Fifth Amendment to Credit Agreement, dated as of October 21, 2022, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
10.51	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	10.2	—	Sixth Amendment to Credit Agreement, dated as of September 26, 2023, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
10.52	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	10.3	—	Seventh Amendment to Credit Agreement, dated as of October 4, 2023, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto

Exhibits	Previously Filed With File Number*	As Exhibit		
10.53	001-38086 Form 10-Q (Quarter ended September 30, 2024) (filed on November 8, 2024)	10.5	—	Eighth Amendment to Credit Agreement, dated as of October 2, 2024, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
10.54	001-38086 Form 8-K (filed on April 1, 2024)	10.1	—	Credit Agreement, dated March 26, 2024, by and among Vistra Zero Operating Company, LLC, the Lenders (as defined in the Credit Agreement) party thereto and Citibank, N.A. (as Administrative Agent and as Collateral Agent)
10.55	001-38086 Form 8-K (filed on December 19, 2024)	10.1	—	First Amendment to Credit Agreement, dated December 17, 2024, by and among Vistra Zero Operating Company, LLC, the guarantors party thereto, the lenders party thereto and Citibank, N.A. (as Administrative Agent and Collateral Agent)
	Other Material Contracts			
10.56	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.5	—	Collateral Trust Agreement, dated as of October 3, 2016, by and among TEX Operations Company LLC (now known as Vistra Operations LLC), the Grantors from time to time thereto, Railroad Commission of Texas, as first-out representative, and Deutsche Bank AG, New York Branch, as senior credit agreement representative
10.57	001-38086 Form 8-K (filed on June 15, 2018)	10.2	—	Amendment to Collateral Trust Agreement, effective as of June 14, 2018, among Vistra Operations Company LLC, the other Grantors from time to time party thereto, Railroad Commission of Texas, as first-out representative, and Credit Suisse AG, Cayman Islands Branch, as senior credit agreement agent, and Delaware Trust Company, as Collateral Trustee
10.58	001-38086 Form 8-K (filed on June 15, 2018)	10.3	—	Collateral Trust Joinder, dated June 14, 2018, between the Additional Grantors party thereto and Delaware Trust Company, as Collateral Trustee, to the Collateral Trust Agreement, effective pursuant to the Seventh Amendment as of June 14, 2018, among Vistra Operations Company LLC, the other Grantors from time to time party thereto, Railroad Commission of Texas, as First-Out Representative, Credit Suisse AG, Cayman Islands Branch, as Senior Credit Agreement Agent, and Delaware Trust Company, as Collateral Trustee.
10.59	001-38086 Form 8-K (filed on January 4, 2024)	10.1	—	Amended and Restated Tax Receivable Agreement, dated December 29, 2023, by and between the Company and Equiniti Trust Company, LLC
10.60	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.14	—	Tax Matters Agreement, by and among TEX Energy LLC (now known as Vistra Corp.), EFH Corp., Energy Future Intermediate Holding Company LLC, EFI Finance Inc. and EFH Merger Co. LLC, dated as of October 3, 2016
10.61	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.18	—	Amended and Restated Split Participant Agreement, by and between Oncor Electric Delivery Company LLC (f/k/a TXU Electric Delivery Company) and TEX Operations Company LLC (now known as Vistra Operations Company LLC), dated as of October 3, 2016
10.62	001-38086 Form 8-K (filed on October 16, 2020)	10.1	—	Master Framework Agreement, dated as of October 9, 2020, by and among TXU Energy Retail Company LLC, as seller and seller party agent, certain originators named therein, and MUFG Bank, Ltd., as buyer
10.63	001-38086 Form 8-K (filed on July 15, 2021)	10.1	—	Amendment No. 1 to Master Framework Agreement, dated as of July 1, 2021, by and among TXU Energy Retail Company LLC, as seller and seller party agent, certain originators named therein, Vistra Operations Company LLC, as guarantor, and MUFG Bank, Ltd., as buyer

Exhibits	Previously Filed With File Number*	As Exhibit		
10.64	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	10.2	—	Amendment No. 2 to Master Framework Agreement, dated as of August 3, 2021, by and among TXU Energy Retail Company LLC, as seller and seller party agent, certain originators named therein, Vistra Operations Company LLC, as guarantor, and MUFG Bank, Ltd., as buyer
10.65	001-38086 Form 8-K (filed on July 15, 2022)	10.1	—	Amendment No. 3 to Master Framework Agreement, dated as of July 11, 2022, by and among TXU Energy Retail Company LLC, as seller and seller party agent, certain originators named therein, Vistra Operations Company LLC, as guarantor, and MUFG Bank, Ltd., as buyer
10.66	001-38086 Form 8-K (filed on July 17, 2023)	10.1	—	Amendment No. 4 to Master Framework Agreement, dated as of July 11, 2023, by and among TXU Energy Retail Company LLC, as seller and seller party agent, certain originators name therein, Vistra Operations Company LLC, as guarantor, and MUFG Bank, Ltd., as buyer
10.67	001-38086 Form 8-K (filed on July 12, 2024)	10.1	—	Amendment No. 5 to Master Framework Agreement, dated as of July 11, 2024, by and among TXU Energy Retail Company LLC, as seller and seller party agent, certain originators name therein, Vistra Operations Company LLC, as guarantor, and MUFG Bank, Ltd., as buyer
10.68	001-38086 Form 8-K (filed on October 16, 2020)	10.2	—	Master Repurchase Agreement, dated as of October 9, 2020, between TXU Energy Retail Company LLC and MUFG Bank, Ltd.
10.69	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	10.3	—	Amendment No. 1 to Master Repurchase Agreement, dated as of August 3, 2021, between TXU Energy Retail Company LLC and MUFG Bank, Ltd.
10.70	001-38086 Form 8-K (filed on December 28, 2020)	10.1	—	Joinder Agreement, dated as of December 21, 2020, among TXU Energy Retail company LLC, as seller party agent, Vistra Operations Company LLC, as guarantor, certain originators named therein, and MUFG Bank, Ltd., as buyer
10.71	001-38086 Form 10-K (Year ended December 31, 2021) (filed on February 25, 2022)	10.62	—	Amendment No. 2 to Master Repurchase Agreement, dated as of December 30, 2021, between TXU Energy Retail Company LLC and MUFG Bank, Ltd.
10.72	001-38086 Form 8-K (filed on July 17, 2023)	10.2	—	Amendment No. 3 to Master Repurchase Agreement, dated as of July 11, 2023, by and among TXU Energy Retail Company LLC, as seller and MUFG Bank, Ltd., as buyer
10.73	001-38086 Form 8-K (filed on April 9, 2024)	10.1	—	Joinder Agreement, dated as of April 8, 2024, among TXU Retail, as seller party agent, Vistra Operations, as guarantor, certain originators named therein, and MUFG, as buyer
10.74	001-38086 Form 8-K (filed on July 12, 2024)	10.2	—	Amendment No. 4 to Master Repurchase Agreement, dated as of July 11, 2024, by and among TXU Energy Retail Company LLC, as seller and MUFG Bank, Ltd., as buyer
10.75	001-38086 Form 8-K (filed on November 19, 2024)	10.1	—	Letter Agreement, dated November 17, 2024, by and among Vistra Operations Company LLC, Vistra Vision Holdings I LLC, and VV Aggregator Holdings 1 LLC
10.76	**		—	Amended and Restated Class B Unit Purchase Agreement, dated December 11, 2024, by and among Vistra Operations Company LLC, Vistra Vision Holdings I LLC, and Nuveen Asset Management, LLC
(19)	**Insider Trading Policy**			
19.1	**		—	Transactions in Vistra Corp. Securities Policy

Exhibits	Previously Filed With File Number*	As Exhibit		
(21)	**Subsidiaries of the Registrant**			
21.1	**		—	Significant Subsidiaries of Vistra Corp.
(23)	**Consent of Experts**			
23.1	**		—	Consent of Deloitte & Touche LLP
(31)	**Rule 13a-14(a) / 15d-14(a) Certifications**			
31.1	**		—	Certification of James A. Burke, principal executive officer of Vistra Corp., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	**		—	Certification of Kristopher E. Moldovan, principal financial officer of Vistra Corp., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(32)	**Section 1350 Certifications**			
32.1	***		—	Certification of James A. Burke, principal executive officer of Vistra Corp., pursuant to U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	***		—	Certification of Kristopher E. Moldovan, principal financial officer of Vistra Corp., pursuant to U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(95)	**Mine Safety Disclosures**			
95.1	**		—	Mine Safety Disclosures
(97)	**Policy Relating to Recover of Erroneously Awarded Compensation**			
97.1	001-38086 Form 10-K (Year ended December 31, 2023) (filed on February 29, 2024)	97.1	—	Vistra Corp. Clawback Policy
	XBRL Data Files			
101.INS	**		—	The following financial information from Vistra Corp.'s Annual Report on Form 10-K for the period ended December 31, 2024 formatted in Inline XBRL (Extensible Business Reporting Language) includes: (i) the Consolidated Statements of Operations, (ii) the Consolidated Statements of Comprehensive Income (Loss), (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statement of Changes in Equity and (vi) the Notes to the Consolidated Financial Statements.
101.SCH	**		—	XBRL Taxonomy Extension Schema Document
101.CAL	**		—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	**		—	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	**		—	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	**		—	XBRL Taxonomy Extension Presentation Linkbase Document
104			—	The Cover Page Interactive Data File does not appear in Exhibit 104 because its XBRL tags are embedded within the Inline XBRL document.

* Incorporated herein by reference
** Filed herewith
*** Furnished herewith

Item 16. FORM 10-K SUMMARY

None.

SIGNATURES

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

VISTRA CORP.

Date: February 27, 2025

By /s/ JAMES A. BURKE

James A. Burke (President and Chief Executive Officer)

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

Signature	Title	Date
/s/ JAMES A. BURKE (James A. Burke, President and Chief Executive Officer)	Principal Executive Officer and Director	February 27, 2025
/s/ KRISTOPHER E. MOLDOVAN (Kristopher E. Moldovan, Chief Financial Officer)	Principal Financial Officer	February 27, 2025
/s/ MARGARET MONTEMAYOR (Margaret Montemayor, Senior Vice President, Chief Accountant and Controller)	Principal Accounting Officer	February 27, 2025
/s/ SCOTT B. HELM (Scott B. Helm, Chairman of the Board)	Chairman of the Board and Director	February 27, 2025
/s/ HILARY E. ACKERMANN (Hilary E. Ackermann)	Director	February 27, 2025
/s/ ARCILIA C. ACOSTA (Arcilia C. Acosta)	Director	February 27, 2025
/s/ GAVIN R. BAIERA (Gavin R. Baiera)	Director	February 27, 2025
/s/ PAUL M. BARBAS (Paul M. Barbas)	Director	February 27, 2025
/s/ LISA CRUTCHFIELD (Lisa Crutchfield)	Director	February 27, 2025
/s/ JULIE A. LAGACY (Julie A. Lagacy)	Director	February 27, 2025
/s/ JOHN W. PITESA (John W. Pitesa)	Director	February 27, 2025
/s/ JOHN R. SULT (John R. Sult)	Director	February 27, 2025
/s/ ROBERT C. WALTERS (Robert C. Walters)	Director	February 27, 2025

STOCKHOLDER INFORMATION

Stock Exchange Listing
NYSE: VST

Corporate Headquarters
Vistra Corp.
6555 Sierra Drive
Irving, Texas 75039

Stock Transfer Agent and Registrar
Please direct general questions about stockholder accounts, stock certificates, transfer of shares, or duplicate mailings to Vistra's transfer agent:

Equiniti Trust Company, LLC
6201 15th Avenue
Brooklyn, NY 11219
Phone: (800) 937-5449
(718) 921-8124
Email: HelpAST@equiniti.com

Independent Registered Accounting Firm
Deloitte & Touche LLP

Officer Certifications
Our Annual Report on Form 10-K filed with the SEC is included herein, excluding all exhibits. We will send stockholders copies of the exhibits to our Annual Report on Form 10-K and any of our corporate governance documents, free of charge, upon request.

Note that these documents, along with further information about our company, board of directors, management team and investor relations contact details, are available on our website at www.vistracorp.com.

Board of Directors †
Hilary E. Ackermann (4*,5)
Arcilia C. Acosta (1,3)
Gavin R. Baiera (2,4)
Paul M. Barbas (1,3,5)
Jim Burke
Lisa Crutchfield (2*)
Scott B. Helm,
Chairman of the Board of Directors
Julie A. Lagacy (3*,4)
John W. (Bill) Pitesa (2,5*)
John R. (J. R.) Sult (1*)
Robert C. Walters (3,4)

[1] Audit Committee
[2] Social Responsibility and Compensation Committee
[3] Nominating and Governance Committee
[4] Sustainability and Risk Committee
[5] Generation and Safety Oversight Committee
* Committee Chair

† As of March 19, 2025, besides Jim Burke, all members of the Vistra Board of Directors satisfy the independence requirements of the Securities and Exchange Commission and the NYSE.

VISTRA

6555 Sierra Drive, Irving, Texas 75039 | www.vistracorp.com