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, 2023
-OR-

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

Commission file number 1-12291

THE AES CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**54-1163725**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
4300 Wilson Boulevard **Arlington, Virginia**	**22203**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (703) 522-1315

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	**AES**	**New York Stock Exchange**

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive 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 ☐ Smaller reporting company ☐ Emerging growth company ☐ Non-accelerated filer ☐

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 restatement 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 ☒

The aggregate market value of the voting and non-voting common equity held by non-affiliates on June 30, 2023, the last business day of the Registrant's most recently completed second fiscal quarter (based on the closing sale price of $20.73 of the Registrant's Common Stock, as reported by the New York Stock Exchange on such date) was approximately $13.88 billion.

The number of shares outstanding of Registrant's Common Stock, par value $0.01 per share, on February 22, 2024 was 710,287,083.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Registrant's Proxy Statement for its 2024 annual meeting of stockholders are incorporated by reference in Parts II and III

The AES Corporation Fiscal Year 2023 Form 10-K

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Glossary of Terms

The following is a list of frequently used terms and abbreviations that appear in the text of this report and have the definitions indicated below:

ACED	AES Clean Energy Development, LLC
Adjusted EBITDA	Adjusted earnings before interest income and expense, taxes, depreciation and amortization, a non-GAAP measure of operating performance
Adjusted EBITDA with Tax Attributes	Adjusted earnings before interest income and expense, taxes, depreciation and amortization, adding back the pre-tax effect of Production Tax Credits, Investment Tax Credits and depreciation tax expense allocated to tax equity investors, a non-GAAP measure
Adjusted EPS	Adjusted Earnings Per Share, a non-GAAP measure
Adjusted PTC	Adjusted Pre-tax Contribution, a non-GAAP measure of operating performance
AES	The Parent Company and its subsidiaries and affiliates
AES Andes	AES Andes S.A., formerly AES Gener
AES Brasil	AES Brasil Operações S.A., formerly branded as AES Tietê
AES Indiana	Indianapolis Power & Light Company, formerly branded as IPL. AES Indiana is wholly-owned by IPALCO
AES Ohio	The Dayton Power & Light Company, formerly branded as DP&L. AES Ohio is wholly-owned by DPL
AES Renewable Holdings	AES Renewable Holdings, LLC, formerly branded as AES Distributed Energy
AFUDC	Allowance for Funds Used During Construction
AIMCo	Alberta Investment Management Corporation
ANEEL	Brazilian National Electric Energy Agency
AOCL	Accumulated Other Comprehensive Loss
ARO	Asset Retirement Obligations
ASC	Accounting Standards Codification
BACT	Best Available Control Technology
BESS	Battery energy storage system
BOT	Build, Operate and Transfer
CAA	U.S. Clean Air Act
CAMMESA	Wholesale Electric Market Administrator in Argentina
CCEE	Brazilian Chamber of Electric Energy Commercialization
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals, which includes bottom ash, fly ash and air pollution control wastes generated at coal-fired generation plant sites
CDPQ	La Caisse de dépôt et placement du Quebéc
CECL	Current Expected Credit Loss
CEO	Chief Executive Officer
CFE	Federal Electricity Commission in Mexico
CFO	Chief Financial Officer
CO_2	Carbon Dioxide
COD	Commercial Operation Date
CPI	U.S. Consumer Price Index
CSAPR	U.S. Cross-State Air Pollution Rule
CWA	U.S. Clean Water Act
DG Comp	Directorate-General for Competition of the European Commission
DOJ	U.S. Department of Justice
DPL	DPL Inc.
DPP	Dominican Power Partners
EBITDA	Earnings before interest income and expense, taxes, depreciation and amortization, a non-GAAP measure of operating performance
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
ERCOT	Electric Reliability Council of Texas
ESP	Electric Security Plan
EU	European Union
EURIBOR	Euro Inter Bank Offered Rate
EVN	Electricity of Vietnam
FERC	U.S. Federal Energy Regulatory Commission
Fluence	Fluence Energy, Inc and its subsidiaries, including Fluence Energy, LLC, which was previously our joint venture with Siemens AG (Nasdaq: FLNC)
FONINVEMEM	Fund for the Investment Needed to Increase the Supply of Electricity in the Wholesale Market in Argentina

FPA	U.S. Federal Power Act
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
GILTI	Global Intangible Low Taxed Income
GSF	Generation Scaling Factor
GW	Gigawatts
GWh	Gigawatt Hours
HLBV	Hypothetical Liquidation Book Value
IPALCO	IPALCO Enterprises, Inc.
IPP	Independent Power Producers
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
LIBOR	London Inter Bank Offered Rate
LNG	Liquefied Natural Gas
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British Thermal Units
MRE	Energy Reallocation Mechanism
MW	Megawatts
MWh	Megawatt Hours
NAAQS	U.S. National Ambient Air Quality Standards
NCI	Noncontrolling Interest
NEK	Natsionalna Elektricheska Kompania (state-owned electricity public supplier in Bulgaria)
NERC	North American Electric Reliability Corporation
NM	Not Meaningful
NOV	Notice of Violation
NO_X	Nitrogen Dioxide
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
O&M	Operations and Maintenance
ONS	National System Operator in Brazil
OTC Policy	Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling
OVEC	Ohio Valley Electric Corporation, an electric generating company in which AES Ohio has a 4.9% interest
Parent Company	The AES Corporation
PCU	Performance Cash Units
Pet Coke	Petroleum Coke
PJM	PJM Interconnection, LLC
PM	Particulate Matter
PPA	Power Purchase Agreement
PREPA	Puerto Rico Electric Power Authority
PSU	Performance Stock Unit
PUCO	The Public Utilities Commission of Ohio
PURPA	U.S. Public Utility Regulatory Policies Act
QF	Qualifying Facility
RSU	Restricted Stock Unit
RTO	Regional Transmission Organization
SADI	Argentine Interconnected System
SBU	Strategic Business Unit
SEC	U.S. Securities and Exchange Commission
SEN	Sistema Electrico Nacional in Chile
SIN	National Interconnected System in Colombia
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SWRCB	California State Water Resources Board
TCJA	Tax Cuts and Jobs Act
TDSIC	Transmission, Distribution, and Storage System Improvement Charge
U.S.	United States
USD	United States Dollar
VAT	Value Added Tax
VIE	Variable Interest Entity
Vinacomin	Vietnam National Coal-Mineral Industries Holding Corporation Ltd.

PART I

In this Annual Report the terms “AES,” “the Company,” “us,” or “we” refer to The AES Corporation and all of its subsidiaries and affiliates, collectively. The terms “The AES Corporation” and “Parent Company” refer only to the parent, publicly held holding company, The AES Corporation, excluding its subsidiaries and affiliates.

Forward-Looking Information and Risk Factor Summary

In this filing we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. Such statements are “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. Although we believe that these forward-looking statements and the underlying assumptions are reasonable, we cannot assure you that they will prove to be correct.

Forward-looking statements involve a number of risks and uncertainties, and there are factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements. Some of those factors (in addition to others described elsewhere in this report and in subsequent securities filings) include:

- the economic climate, particularly the state of the economy in the areas in which we operate, which impacts demand for electricity in many of our key markets, including the fact that the global economy faces considerable uncertainty for the foreseeable future, which further increases many of the risks discussed in this Form 10-K;
- changes in the price of electricity at which our generation businesses sell into the wholesale market and our utility businesses purchase to distribute to their customers, and the success of our risk management practices, such as our ability to hedge our exposure to such market price risk;
- changes in the prices and availability of coal, gas and other fuels (including our ability to have fuel transported to our facilities) and the success of our risk management practices, such as our ability to hedge our exposure to such market price risk, and our ability to meet credit support requirements for fuel and power supply contracts;
- changes in and access to the financial markets, particularly changes affecting the availability and cost of capital in order to refinance existing debt and finance capital expenditures, acquisitions, investments and other corporate purposes;
- changes in inflation, demand for power, interest rates and foreign currency exchange rates, including our ability to hedge our interest rate and foreign currency risk;
- our ability to fulfill our obligations, manage liquidity and comply with covenants under our recourse and non-recourse debt, including our ability to manage our significant liquidity needs and to comply with covenants under our revolving credit facility and other existing financing obligations;
- our ability to receive funds from our subsidiaries by way of dividends, fees, interest, loans or otherwise;
- changes in our or any of our subsidiaries' corporate credit ratings or the ratings of our or any of our subsidiaries' debt securities or preferred stock, and changes in the rating agencies' ratings criteria;
- our ability to purchase and sell assets at attractive prices and on other attractive terms;
- our ability to compete in markets where we do business;
- our ability to operate power generation, distribution and transmission facilities, including managing availability, outages and equipment failures;
- our ability to manage our operational and maintenance costs and the performance and reliability of our generating plants, including our ability to reduce unscheduled down times;
- our ability to enter into long-term contracts, which limit volatility in our results of operations and cash flow, such as PPAs, fuel supply, and other agreements and to manage counterparty credit risks in these agreements;
- variations in weather, especially mild winters and cooler summers in the areas in which we operate, the occurrence of difficult hydrological conditions for our hydropower plants, as well as hurricanes and other storms and disasters, wildfires and low levels of wind or sunlight for our wind and solar facilities;
- pandemics, or the future outbreak of any other highly infectious or contagious disease;
- the performance of our contracts by our contract counterparties, including suppliers or customers;
- severe weather and natural disasters;

- our ability to manage global supply chain disruptions;
- our ability to raise sufficient capital to fund development projects or to successfully execute our development projects;
- the success of our initiatives in renewable energy projects and energy storage projects;
- the availability of government incentives or policies that support the development of renewable energy generation projects;
- our ability to execute on our strategies or achieve expectations related to environmental, social, and governance matters;
- our ability to keep up with advances in technology;
- changes in number of customers or in customer usage;
- the operations of our joint ventures and equity method investments that we do not control;
- our ability to achieve reasonable rate treatment in our utility businesses;
- changes in laws, rules and regulations affecting our international businesses, particularly in developing countries;
- changes in laws, rules and regulations affecting our utilities businesses, including, but not limited to, regulations which may affect competition, the ability to recover net utility assets and other potential stranded costs by our utilities;
- changes in law resulting from new local, state, federal or international energy legislation and changes in political or regulatory oversight or incentives affecting our wind business and solar projects, our other renewables projects and our initiatives in GHG reductions and energy storage, including government policies or tax incentives;
- changes in environmental laws, including requirements for reduced emissions, GHG legislation, regulation, and/or treaties and CCR regulation and remediation;
- changes in tax laws, including U.S. tax reform, and challenges to our tax positions;
- the effects of litigation and government and regulatory investigations;
- the performance of our acquisitions;
- our ability to maintain adequate insurance;
- decreases in the value of pension plan assets, increases in pension plan expenses, and our ability to fund defined benefit pension and other postretirement plans at our subsidiaries;
- losses on the sale or write-down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets;
- changes in accounting standards, corporate governance and securities law requirements;
- our ability to maintain effective internal controls over financial reporting;
- our ability to attract and retain talented directors, management and other personnel;
- cyber-attacks and information security breaches; and
- data privacy.

These factors, in addition to others described elsewhere in this Form 10-K, including those described under Item 1A.—*Risk Factors* and in subsequent securities filings, should not be construed as a comprehensive listing of factors that could cause results to vary from our forward-looking information.

We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise. If one or more forward-looking statements are updated, no inference should be drawn that additional updates will be made with respect to those or other forward-looking statements.

ITEM 1. BUSINESS

Item 1.—*Business* is an outline of our strategy and our businesses by SBU, including key financial drivers. Additional items that may have an impact on our businesses are discussed in Item 1A.—*Risk Factors* and Item 3.—*Legal Proceedings*.

Executive Summary

Incorporated in 1981, AES is a global energy company accelerating the future of energy. Together with our many stakeholders, we are improving lives by delivering the greener, smarter energy solutions the world needs. Our diverse workforce is committed to continuous innovation and operational excellence, while partnering with our customers on their strategic energy transitions and continuing to meet their energy needs today.

MISSION

Accelerating the future of energy, together.

4 MARKET-ORIENTED STRATEGIC BUSINESS UNITS

34,596 Gross MW in Operation*

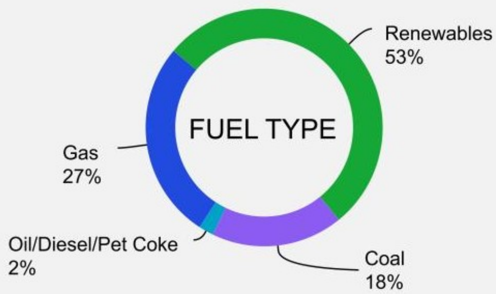
Generation Capacity Under Construction 5,116MW

VALUES

Safety first

Highest standards

All together



$12.7B TOTAL 2023 REVENUES

$45B TOTAL ASSETS OWNED & MANAGED

AES IS ENERGIZED BY A GLOBAL WORKFORCE OF APPROXIMATELY 9,600 PEOPLE

6 UTILITY COMPANIES

AES Serves 2.6M UTILITY CUSTOMERS

*24,047 proportional MW (gross MW multiplied by AES' equity ownership percentage)

Our Strategy

AES remains an industry leader in developing and operating the innovative solutions that enable the transition to zero and low-carbon sources of energy. We continue to see an enormous opportunity from the once-in-a-lifetime transformation of the electricity sector driven by decarbonization, electrification, and digitalization.

The focus of our strategy is to partner with large corporations that are transitioning to carbon-free sources of electricity. One example of our successful execution is our collaboration with large technology companies. Specifically, demand from data centers in the U.S. is expected to nearly double in the next three years. Our well-established relationships with these customers, combined with our proven track record of delivering our projects, positions us well to take advantage of this opportunity.

In 2023, we signed long-term contracts for 5.6 GW of renewables, bringing our backlog of projects — those with signed contracts, but which are not yet in operation — to 12.3 GW. Our backlog serves as the core component of future growth. As a result, we have been consistently rated by Bloomberg New Energy Finance as one of the top two largest sellers globally of renewable power to corporate customers, with a focus on large technology/data center providers.

We are a leader in developing green hydrogen. We are partnering with Air Products to develop, build, own, and operate the largest green hydrogen production facility in the United States. We are also participating in two green hydrogen hubs in the United States, which were awarded up to $2.4 billion of grant funding from the U.S. Department of Energy.

With our utilities, we are working with a broad range of stakeholders to transition to lower carbon forms of energy. At AES Indiana, for example, we are working to retire its remaining coal generation by the end of 2025, while adding new renewables and natural gas to the grid.

We are also developing and incubating new technologies that add value today and will drive our business in the future. We understand that the energy industry is changing rapidly, and aim to proactively seek solutions that will give us a continued competitive advantage. At the core of our innovation strategy is AES Next, our business and technology incubator. AES Next works to identify new and innovative technologies and business opportunities that provide or support leading-edge greener energy solutions.

2023 Strategic Highlights

- We signed 5.6 GW of renewables and energy storage under long-term PPAs.
- We completed the construction of 3.5 GW.
- Our backlog, which includes projects with signed contracts, but which are not yet operational, is now 12.3 GW, consisting of:
  - 5.1 GW under construction; and
  - 7.2 GW with signed PPAs, but that are not yet under construction.
- AES Indiana reached a unanimous settlement agreement for its first rate case since 2018, and expects to receive approval from the IURC by the middle of 2024.
- AES Ohio received approval from the PUCO for its Electric Security Plan (ESP4), providing the regulatory foundation necessary to enable future investments.
- We exited or announced the sale or closure of 2.1 GW of coal generation in Vietnam, the U.S., and Chile.
- We signed agreements for three-year extensions of 1.4 GW of gas generation at the Southland legacy units in Southern California. These extensions will help meet the State of California's grid reliability needs while supporting its decarbonization goals.
- Awarded up to $2.4 billion of grant funding by the U.S. Department of Energy for two green hydrogen hubs with AES participation.
- We secured $1.1 billion in asset sale proceeds, to accelerate our portfolio transformation, outpacing our target of $400 to $600 million.

Overview

Generation

We currently own and/or operate a generation portfolio of 34,596 MW, including generation from our integrated utility, AES Indiana. Our generation fleet is diversified by technologies and fuel type. See discussion below under *Fuel Costs*.

Performance drivers of our generation businesses include types of electricity sales agreements, plant reliability and flexibility, availability of generation capacity to meet contracted sales, fuel costs, seasonality, weather variations, economic activity, fixed-cost management, and competition. The financial performance of our renewables business is also impacted by our ability to complete construction projects and earn U.S. renewable tax credits.

Contract Sales — Most of our generation businesses sell electricity under medium- or long-term contracts in either regulated or competitive markets ("contract sales") or under short-term agreements in competitive markets ("short-term sales"). Our medium-term contract sales have terms of two to five years, while our long-term contracts have terms of more than five years.

Contracts requiring fuel to generate energy, such as natural gas or coal, are structured to recover variable costs, including fuel and variable O&M costs, either through direct or indexation-based contractual pass-throughs or tolling arrangements. When the contract does not include a fuel pass-through, we typically hedge fuel costs or enter into fuel or energy supply agreements for a similar contract period (see discussion below under *Fuel Costs*). These contracts also help us to fund a significant portion of the total capital cost of the project through long-term non-recourse project-level financing.

Certain contracts include capacity payments that cover projected fixed costs of the plant, including fixed O&M expenses, debt service, and a return on capital invested. In addition, most of our contracts require that the majority of the capacity payments be denominated in the currency matching our fixed costs. In some U.S. markets, the capacity payment is only for the resource adequacy or reliability benefits from the generating facility, allowing us to separately monetize the electricity produced by the facility through either contract sales or short-term sales.

Contracts that do not have significant fuel cost or do not contain a capacity payment are structured based on long-term prices and may also include negotiated pass-through costs, allowing us to recover expected fixed and variable costs as well as provide a return on investment.

Many of these contracts are intended to reduce exposure to the volatility of fuel and electricity prices by linking the business's revenues and costs. We generally structure our business to eliminate or reduce foreign exchange risk by matching the currency of revenue and expenses, including fixed costs and debt. Our project debt may consist of both fixed and floating rate debt for which we typically hedge a significant portion of our exposure. Some of our contracted businesses also receive a regulated market-based capacity payment, which is discussed in more detail in the *Short-Term Sales* section below.

Thus, these contracts, or other related commercial arrangements, significantly mitigate our exposure to changes in electricity and, as applicable, fuel prices, currency fluctuations and changes in interest rates. In addition, these contracts generally provide or account for a recovery of our fixed operating expenses and a return on our investment, as long as we operate the plant to the reliability, availability, and efficiency standards required in the contract or otherwise.

Short-Term Sales — Our generation businesses also sell power and ancillary services under short-term contracts with average terms of less than two years, including spot sales, directly in the short-term market or at regulated prices. The short-term markets are typically administered by a system operator to coordinate dispatch. Short-term markets generally operate on merit order dispatch, where the least expensive generation facilities, based upon variable cost or bid price, are dispatched first and the most expensive facilities are dispatched last. The short-term price is typically set at the marginal cost of energy or bid price (the cost of the last plant required to meet system demand). As a result, the cash flows and earnings associated with these businesses are more sensitive to fluctuations in the market price for electricity. In addition, many of these wholesale markets include markets for ancillary services to support the reliable operation of the transmission system. Across our portfolio, we provide a wide array of ancillary services, including voltage support, frequency regulation and spinning reserves.

Many of the short-term markets in which we operate include regulated capacity markets. These capacity markets are intended to provide additional revenue based upon availability without reliance on the energy margin from the merit order dispatch. Capacity markets are typically priced based on the cost of a new entrant and the system capacity relative to the desired level of reserve margin (generation available in excess of peak demand). Our generating facilities selling in the short-term markets typically receive capacity payments based on their availability in the market.

Plant Reliability and Flexibility — Our contract and short-term sales provide incentives to our generation plants to optimally manage availability, operating efficiency and flexibility. Capacity payments under contract sales are frequently tied to meeting minimum standards. In short-term sales and in certain contract sales, our plants must be reliable and flexible to capture peak market prices and to maximize market-based revenues. In addition, our flexibility allows us to capture ancillary service revenue while meeting local market needs.

Fuel Costs — For our thermal generation plants, fuel is a significant component of our total cost of generation. For contract sales, we often enter into fuel supply agreements to match the contract period, or we may financially hedge our fuel costs. Some of our contracts include indexation for fuels. In those cases, we seek to match our fuel supply agreements to the indexation. For certain projects, we have tolling arrangements where the power offtaker is responsible for the supply and cost of fuel to our plants.

In short-term sales, we sell power at market prices that are generally reflective of the market cost of fuel at the time, and thus procure fuel supply on a short-term basis, generally designed to match up with our market sales profile. Since fuel price is often the primary determinant for power prices, the economics of projects with short-term sales are often subject to volatility of relative fuel prices. For further information regarding commodity price risk please see Item 7A.—*Quantitative and Qualitative Disclosures about Market Risk* in this Form 10-K.

53% of the capacity of our generation plants are renewables, including hydro, solar, wind, energy storage, biomass and landfill gas, which do not have significant fuel costs.

27% of the capacity of our generation plants are fueled by natural gas. With the exception of our plants in the Dominican Republic and Panama, where we import LNG to utilize in the local market, we use gas from local suppliers in each market.

18% of the capacity of our generation fleet is coal-fired. In the U.S., most of our coal-fired plants are supplied from domestic coal. At our non-U.S. generation plants, and at our plant in Puerto Rico, we source coal from a mix of sources from the international market and in the local jurisdictions. To the extent possible, we utilize our global sourcing program to maximize the purchasing power of our fuel procurement.

2% of the capacity of our generation fleet utilizes pet coke or oil for fuel. We source oil and diesel locally at prices linked to international markets. We largely source pet coke from Mexico and the U.S.

Seasonality, Weather Variations and Economic Activity — Our generation businesses are affected by seasonal weather patterns and, therefore, operating margin is not generated evenly throughout the year. Additionally, weather variations, including temperature, solar and wind resources, and hydrological conditions, may also have an impact on generation output at our renewable generation facilities. In competitive markets for power, local economic activity can also have an impact on power demand and short-term prices for power.

Fixed-Cost Management — In our businesses with long-term contracts, the majority of the fixed O&M costs are recovered through the capacity payment or were otherwise factored in as a component of the long-term contract price. However, for all generation businesses, managing fixed costs and reducing them over time is a driver of business performance.

Competition — For our businesses with medium- or long-term contracts, there is limited market competition impacting prices during the term of the contract. For short-term sales, plant dispatch and the price of electricity are determined by market competition and local dispatch and reliability rules.

Utilities

Our utility businesses consist of AES Indiana and AES Ohio in the U.S., and four utilities in El Salvador. AES' six utility businesses distribute power to 2.6 million customers and AES' two utilities in the U.S. also include generation capacity totaling 3,500 MW.

AES Indiana, our fully integrated regulated utility, and AES Ohio, our transmission and distribution regulated utility, each operate as the sole distributors of electricity within their respective jurisdictions. AES Indiana owns and operates all of the facilities necessary to generate, transmit and distribute electricity. AES Ohio owns and operates all of the facilities necessary to transmit and distribute electricity. Our distribution business in El Salvador faces limited competition due to significant barriers to enter the market. According to El Salvador's regulation, large regulated customers have the option of becoming unregulated users and requesting service directly from generation or commercialization agents.

In general, our utilities sell electricity directly to end-users, such as homes and businesses, and bill customers directly. Key performance drivers for utilities include the regulated rate of return and tariff, seasonality, weather variations, economic activity and reliability of service. Revenue from utilities is classified as regulated on the Consolidated Statements of Operations.

Regulated Rate of Return and Tariff — In exchange for the right to sell or distribute electricity in a service territory, our utility businesses are subject to government regulation. This regulation sets the framework for the prices ("tariffs") that our utilities are allowed to charge customers for electricity and establishes service standards that we are required to meet.

Our utilities are generally permitted to earn a regulated rate of return on assets, determined by the regulator based on the utility's allowed regulatory asset base, capital structure and cost of capital. The asset base on which the utility is permitted a return is determined by the regulator, within the framework of applicable local laws, and is based on the amount of assets that are considered used and useful in serving customers. Both the allowed return and the asset base are important components of the utility's earning power. The allowed rate of return and operating expenses deemed reasonable by the regulator are recovered through the regulated tariff that the utility charges to its customers.

The tariff may be reviewed and reset by the regulator from time to time depending on local regulations, or the utility may seek a change in its tariffs. The tariff is generally based upon usage level and may include a pass-through of costs that are not controlled by the utility, such as the costs of fuel (in the case of integrated utilities) and/or the costs of purchased energy, to the customer. Components of the tariff that are directly passed through to the customer are usually adjusted through a summary regulatory process or an existing formula-based mechanism. In some regulatory regimes, customers with demand above an established level are unregulated and can choose to contract directly with the utility or with other retail energy suppliers and pay non-bypassable fees, which are fees to the distribution company for use of its distribution system.

The regulated tariff generally recognizes that our utility businesses should recover certain operating and fixed costs, as well as manage uncollectible amounts, quality of service and technical and non-technical losses. Utilities, therefore, need to manage costs to the levels reflected in the tariff, or risk non-recovery of costs or diminished returns.

Seasonality, Weather Variations, and Economic Activity — Our utility businesses are generally affected by seasonal weather patterns and, therefore, operating margin is not generated evenly throughout the year. Additionally, weather variations may also have an impact based on the number of customers, temperature variances from normal conditions, and customers' historic usage levels and patterns. Retail sales, after adjustments for weather variations, are also affected by changes in local economic activity, energy efficiency and distributed generation initiatives, as well as the number of retail customers.

Reliability of Service — Our utility businesses must meet certain reliability standards, such as duration and frequency of outages. Those standards may be explicit, with defined performance incentives or penalties, or implicit, where the utility must operate to meet customer and/or regulator expectations.

Development and Construction

We develop and construct new generation facilities. For our utility business, new plants may be built or existing plants retrofitted in response to customer needs or to comply with regulatory developments. The projects are developed subject to regulatory approval that permits recovery of our capital cost and a return on our investment. For our generation businesses, our priority for development is in key growth markets, where we can leverage our global scale and synergies with our existing businesses by adding renewable energy. We make the decision to invest in new projects by evaluating the strategic fit, financial profile, projected returns and risk for the investment and against alternative uses of capital, including corporate debt repayment.

In most cases, we enter into long-term contracts for output from new facilities prior to commencing construction. To limit required equity contributions from The AES Corporation, we also seek non-recourse project debt financing and other sources of capital, including partners, when it is commercially attractive. We typically contract with a third party to manage construction, although our construction management team supervises the construction work and tracks progress against the project's budget, schedule, and the required safety, efficiency and productivity standards.

Segments

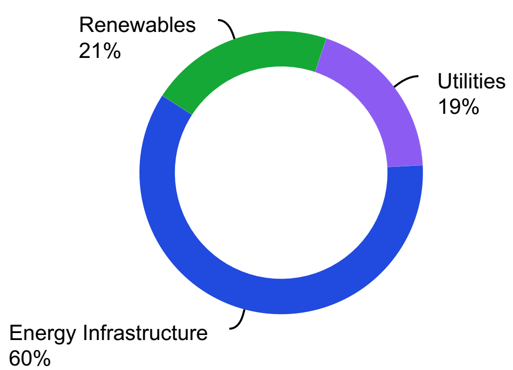
The segment reporting structure uses the Company's management reporting structure as its foundation to reflect how the Company manages the businesses internally and is mainly organized by technology.

We are organized into four technology-oriented SBUs: **Renewables** (solar, wind, energy storage, and hydro generation facilities); **Utilities** (AES Indiana, AES Ohio, and AES El Salvador regulated utilities and their generation facilities); **Energy Infrastructure** (natural gas, LNG, coal, pet coke, diesel, and oil generation facilities, and our businesses in Chile); and **New Energy Technologies** (green hydrogen initiatives and investments in Fluence, Uplight, and 5B) — which are led by our SBU Presidents.

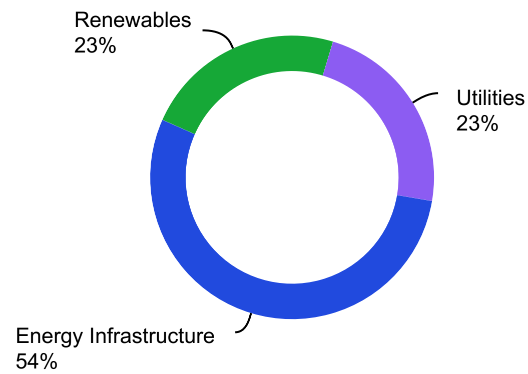
We have two lines of business: generation and utilities. Our Renewables, Utilities, and Energy Infrastructure SBUs participate in our first business line, generation, in which we own and/or operate power plants to generate and sell power to customers, such as utilities, industrial users, and other intermediaries. Our Utilities SBU participates in our second business line, utilities, in which we own and/or operate utilities to generate or purchase, distribute, transmit and sell electricity to end-user customers in the residential, commercial, industrial and governmental sectors within a defined service area. In certain circumstances, our utilities also generate and sell electricity on the wholesale market. Our New Energy Technologies SBU includes investments in new and innovative technologies to support leading-edge greener energy solutions.

We measure the operating performance of our SBUs using Adjusted EBITDA, a non-GAAP measure. The Adjusted EBITDA by SBU for the year ended December 31, 2023 is shown below. The percentages for Adjusted EBITDA are the contribution by each SBU to the gross metric, i.e., the total Adjusted EBITDA by SBU, before deductions for Corporate. Our New Energy Technologies SBU generated losses for the year ended December 31, 2023. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—SBU Performance Analysis* of this Form 10-K for reconciliation and definitions of Adjusted EBITDA.

Operating Margin



Adjusted EBITDA



For financial reporting purposes, the Company's corporate activities are reported within "Corporate and Other" because they do not require separate disclosure. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations* and Note 18—*Segment and Geographic Information* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further discussion of the Company's segment structure.

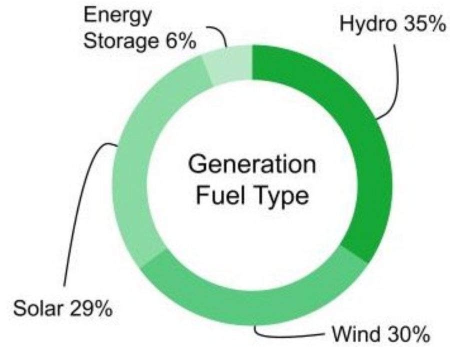
Renewables

Business Overview

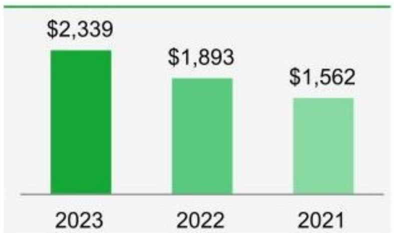
99 Generation Facilities

16,211 Gross MW

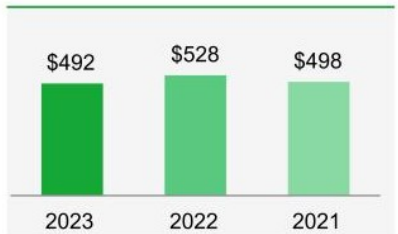
Key Generation Businesses: **AES Clean Energy, AES Brasil, and Chivor**



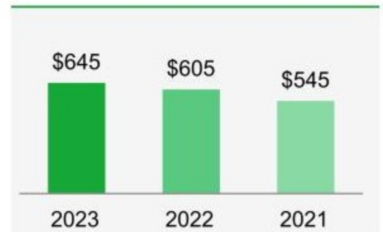
Revenue
(In millions)



Operating Margin
(in millions)



Adjusted EBITDA [1]
(in millions)



Key events in 2023

- Completed construction of 2.9 GW of new renewables
- Signed long-term PPAs for 4.9 GW of new renewables

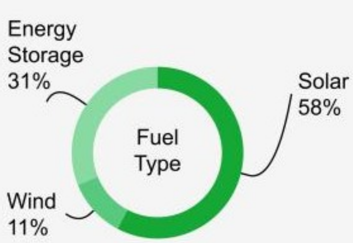
Strategic outlook

- Total backlog of 7.9 GW of renewables under signed long-term PPAs

Under construction

24 Plants

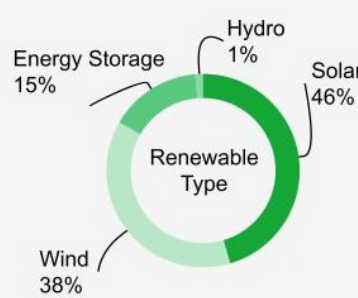
3,366 MW



Contracted renewable backlog

4,577 MW

Signed PPAs not yet under construction



(1) Non-GAAP measure. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—SBU Performance Analysis—Non-GAAP Measures* for reconciliation and definition.

Our Renewables SBU is the highest growth segment for AES, adding 4.9 GW to our contracted backlog during 2023, including 1.2 GW with large technology companies.

Specifically, demand from data centers in the U.S. is expected to nearly double in the next three years as generative artificial intelligence use-cases expand. Our well-established relationships with these customers, combined with our proven track record of delivering our projects, positions us well to take advantage of this opportunity.

The Renewables SBU has generation facilities in ten countries — the United States, Brazil, Argentina, Colombia, Mexico, Panama, Bulgaria, the Dominican Republic, Jordan, and the Netherlands.

Generation — Total operating installed capacity of the Renewables SBU is 16,211 MW. The following table lists our Renewables SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
AES Brasil Operacoes (AES Tietê) [1]	Brazil	Hydro	2,658	47 %	1999	2032	Various
Alicura [9]	Argentina	Hydro	1,050	100 %	2000		
Chivor	Colombia	Hydro	1,000	99 %	2000	2024-2039	Various
OpCo A [2]	US-Various	Solar	967	26 %	2017-2019	2028-2046	Various
		Wind	140				
New York Wind (OpCo D) [3]	US-NY	Wind	612	75 %	2021		NYISO
AES Renewable Holdings [3]	US-Various	Solar	414	100 %	2015-2023	2029-2042	Utility, Municipality, Education, Non-Profit
		Energy Storage	90				
Spotsylvania Solar Energy Center (OpCo B) [2]	US-VA	Solar	485	26 %	2020-2021	2035	Apple, Akami, Etsy, Microsoft
Ventos do Araripe, Caetes & Cassino (Cubico II)	Brazil	Wind	456	47 %	2022	2034-2035	Various, CCEE
Alto Sertão II	Brazil	Wind	386	36 %	2017	2033-2035	Various, CCEE
Cajuina 1	Brazil	Wind	314	36%-47%	2023	2035-2043	Various
Mesa La Paz [2]	Mexico	Wind	306	50 %	2019	2045	Fuentes de Energia Peñoles
McFarland A [4]	US-AZ	Solar	200	75 %	2023	2038	BP
		Energy Storage	100				
Cajuina 2	Brazil	Wind	296	36%-47%	2023	2044	Various
OpCo B [2]	US-Various	Solar	260	26 %	2019	2039-2044	Various
Bayano	Panama	Hydro	260	49 %	1999	2030	ENSA, Edemet, Edechi, Other
Chevelon Butte (OpCo D) [3]	US-AZ	Wind	238	75 %	2023	2043	APS
Buffalo Gap II [3]	US-TX	Wind	233	100 %	2007		
Baldy Mesa [4]	US-CA	Solar	150	75 %	2023	2043	Amazon
		Energy Storage	75				
Changuinola	Panama	Hydro	223	90 %	2011	2030	AES Panama
Great Cove 1&2 [4]	US-PA	Solar	220	75 %	2023	2043	University of
Raceway 1	US-CA	Solar	125	50 %	2023	2043	Microsoft
		Energy Storage	80				
Prevailing Winds (OpCo B) [2]	US-SD	Wind	200	26 %	2020	2050	Prevailing Winds
Oak Ridge [4]	US-LA	Solar	200	75 %	2023	2043	Amazon
Ventus	Brazil	Wind	187	36 %	2020	2034	CCEE
Skipjack (OpCo D) [3][4]	US-VA	Solar	175	75 %	2022	2036	Exelon Generation Company
Buffalo Gap III [3]	US-TX	Wind	170	100 %	2008		
Tucano Phase 2	Brazil	Wind	161	47 %	2023	2036	Anglo American
Mandacaru and Salinas	Brazil	Wind	159	47 %	2021	2033-2034	CCEE
St. Nikola	Bulgaria	Wind	156	89 %	2010	2025	Electricity Security Fund
Tucano Phase 1	Brazil	Wind	155	24 %	2022-2023	2042	Unipar
Guaimbê	Brazil	Solar	150	36 %	2018	2037	CCEE

Lancaster Area Battery (LAB) (3)(4)	US-CA	Energy Storage	127	75 %	2022	2037	PG&E
Buffalo Gap I (3)	US-TX	Wind	121	100 %	2006		
Chiriqui-Esti	Panama	Hydro	120	49 %	2003	2030	ENSA, Edemet, Edechi, Other
Cavalier (4)	US-VA	Solar	116	75 %	2023	2043	Dominion Energy
Delta (4)	US-MS	Wind	104	75 %	2023	2043	Amazon
Cabra Corral	Argentina	Hydro	102	100 %	1995		Various
Southland Energy—Alamitos Energy Center (5)	US-CA	Energy Storage	100	50 %	2021	2041	Southern California Edison
East Line Solar (OpCo B) (2)	US-AZ	Solar	100	26 %	2020	2045	Salt River Project
Central Line (OpCo B) (2)	US-AZ	Solar	100	26 %	2022	2039	Salt River Project Agricultural Improvement & Power District
West Line (OpCo B) (2)	US-AZ	Solar	100	26 %	2022	2047	Salt River Project Agricultural Improvement & Power District
Luna (3)	US-CA	Energy Storage	100	75 %	2022	2037	Clean Power Alliance of Southern California
Vientos Bonaerenses	Argentina	Wind	100	100 %	2020	2024-2040	Various
Vientos Neuquinos	Argentina	Wind	100	100 %	2020	2024-2040	Various
Laurel Mountain Repowering (OpCo D) (4)	US-WV	Wind	99	75 %	2022	2037	AES Solutions Management, LLC
McFarland B (4)	US-AZ	Solar	60	75 %	2023	2043	Amazon
		Energy Storage	30				
Estrella	US-CA	Solar	56	50 %	2023	2038	Southern California Edison
		Energy Storage	28				
Platteview (4)	US-NE	Solar	81	75 %	2023	2043	Omaha Public Power District
Clover Creek (OpCo B) (2)	US-UT	Solar	80	50 %	2021	2046	UMPA
Westwing 1 (4)	US-AZ	Energy Storage	77	75 %	2023	2043	APS
AGV Solar	Brazil	Solar	76	36 %	2019	2040	Various, CCEE
OpCo C (3)	US-Various	Solar	73	50 %	2021-2022	2041-2042	Various
Boa Hora	Brazil	Solar	69	47 %	2019	2038	CCEE
Mountain View Repowering (OpCo D) (3)(4)	US-CA	Wind	67	75 %	2022	2042	Southern California Edison
San Fernando	Colombia	Solar	61	99 %	2021	2036	Ecopetrol
Big Island Waikoloa (OpCo E) (3)(6)	US-HI	Solar	30	100 %	2022-2023	2047	HECO
		Energy Storage	30				
Penonome I	Panama	Wind	55	49 %	2020	2030	ENSA, Edemet, Edechi
Chiriqui-Los Valles	Panama	Hydro	54	49 %	1999	2030	ENSA, Edemet, Edechi, Other
Bayasol	Dominican Republic	Solar	50	65 %	2021	2036	Ede Sur
Agua Clara	Dominican Republic	Wind	50	65 %	2022	2039	Ede Norte
Santanasol	Dominican Republic	Solar	50	65 %	2022	2038	Ede Sur
Mountain View IV (OpCo E) (6)	US-CA	Wind	49	100 %	2012	2032	Southern California
Chiriqui-La Estrella	Panama	Hydro	48	49 %	1999	2030	ENSA, Edemet, Edechi, Other
AM Solar (7)	Jordan	Solar	48	36 %	2019	2039	National Electric Power Company
Ullum	Argentina	Hydro	45	100 %	1996		Various
Lawa'i (3)(6)	US-HI	Solar	20	100 %	2018	2043	Kaua'i Island Utility Cooperative
		Energy Storage	20				
OpCo D (2)	US-Various	Solar	38	75 %	2022-2023	2042-2043	Various
		Energy Storage	2				

Kuihelni [4]	US-HI	Solar Energy Storage	14.5 14.5	100 %	2023	2048	HECO
Kekaha [3][6]	US-HI	Solar Energy Storage	14 14	100 %	2019	2045	Kaua'i Island Utility Cooperative
Brisas	Colombia	Solar	27	99 %	2022	2037	Ecopetrol
West Oahu Solar [6]	US-HI	Solar Energy Storage	12.5 12.5	100 %	2023	2048	HECO
Na Pua Makani [6]	US-HI	Wind	24	100 %	2020	2040	HECO
Ilumina	US-PR	Solar	24	100 %	2012	2037	LUMA Energy
Castilla	Colombia	Solar	21	99 %	2019	2034	Ecopetrol
Tunjita	Colombia	Hydro	20	99 %	2016	2024-2039	Various
Laurel Mountain ES	US-WV	Energy Storage	16	100 %	2011		
Community Energy [4]	US-Various	Solar	14	75 %	2022	2024-2043	Various
Southland Energy—AES Gilbert (Salt River [5] [8]	US-AZ	Energy Storage	10	50 %	2019	2039	Salt River Project Agricultural Improvement & Power District
El Tunal	Argentina	Hydro	10	100 %	1995		Various
Andres ES	Dominican Republic	Energy Storage	10	65 %	2017		
Los Mina DPP ES	Dominican Republic	Energy Storage	10	65 %	2017		
Pesé Solar	Panama	Solar	10	49 %	2021	2030	ENSA, Edemet, Edechi, Other
Mayorca Solar	Panama	Solar	10	49 %	2021	2030	ENSA, Edemet, Edechi, Other
Cedro	Panama	Solar	10	49 %	2021	2030	ENSA, Edemet, Edechi, Other
Caoba	Panama	Solar	10	49 %	2021	2030	ENSA, Edemet, Edechi, Other
Netherlands ES	Netherlands	Energy Storage	10	100 %	2015		
Warrior Run ES	US-MD	Energy Storage	5	100 %	2016		
5B Costa Norte	Panama	Solar	1	100 %	2021	2051	Costa Norte LNG Terminal
			16,211				

(1) AES Tietê hydro plants: Água Vermelha (1,396 MW), Bariri (143 MW), Barra Bonita (141 MW), Caconde (80 MW), Euclides da Cunha (109 MW), Ibitinga (132 MW), Limoeiro (32 MW), Mog-Guaçu (7 MW), Nova Avanhandava (347 MW), Promissão (264 MW), Sao Joaquim (3 MW) and Sao Jose (4 MW).

(2) Unconsolidated entity, accounted for as an equity affiliate.

(3) AES owns these assets together with third-party tax equity investors with variable ownership interests. The tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes, that vary over the life of the projects. The proceeds from the issuance of tax equity are recorded as *Noncontrolling interest* or *Redeemable stock of subsidiaries* in the Company's Consolidated Balance Sheets, depending on the partnership rights of the specific project.

(4) Owned by ACED.

(5) On December 1, 2022, Southland Energy sold an additional 14.9% ownership interest in the Southland Energy assets. Following the sale, AES holds 50.1% of Southland Energy's interest and this business continues to be consolidated by AES.

(6) Owned by AES Renewable Holdings.

(7) Announced the sale of 26% of our interest in this business in November 2020.

(8) Facility experienced a fire event in April 2022 which rendered the asset currently inoperable.

(9) Operated by AES under a concession contract granted for a term of 30 years, which was set to expire on August 11, 2023. In accordance with the contract, the concession could be extended with a transitional period up to a maximum of 12 months. The Energy Secretariat has enacted several resolutions since the contractual expiration date extending it until March 18, 2024. Once its term expires, the ownership and possession of the power plant equipment will be transferred by full right to the National State in its capacity as grantor.

Under construction — The majority of projects under construction have executed long-term PPAs or, as applicable, have been assigned tariffs through a regulatory process. The following table lists our plants under construction in the Renewables SBU:

Business	Location	Fuel	Gross MW	AES Equity Interest	Expected Date of Commercial Operations
High Mesa [1]	US-CO	Solar	10	75 %	1H 2024
		Energy Storage	10		
Westwing 1 [1]	US-AZ	Energy Storage	3	75 %	
Delta [1]	US-MS	Wind	81	75 %	1H 2024
Chevelon Butte Phase II [1]	US-AZ	Wind	216	75 %	1H 2024
Kuihelni [2]	US-HI	Solar	45	100 %	1H 2024
		Energy Storage	45		
Cajuína 2	Brazil	Wind	74	47 %	1H 2024
Tucano Phase 2	Brazil	Wind	6	47 %	1H 2024
Mirasol 1&2	Dominican Republic	Solar	100	65 %	1H 2024
AES Clean Energy Development	US-Various	Solar	69	75 %	1H-2H 2024
		Energy Storage	7		
McFarland B [1]	US-AZ	Solar	240	75 %	2H 2024
		Energy Storage	120		
Cavalier [1]	US-VA	Solar	40	75 %	2H 2024
Alamitos 2	US-CA	Energy Storage	82	100 %	2H 2024
Cavalier Solar A2 [1]	US-VA	Solar	84	75 %	2H 2024
Waiwa Phase 2 [1]	US-HI	Solar	30	75 %	2H 2024
		Energy Storage	30		
Peravia I	Dominican Republic	Solar	70	65 %	2H 2024
Calhoun	US-MI	Solar	125	75 %	2H 2024
Mamm Creek	US-CO	Solar	10	75 %	2H 2024
		Energy Storage	10		
AGV VII	Brazil	Solar	33	47 %	2H 2024
Los Santos Solar	Panama	Solar	8	49 %	2H 2024
Corotu Solar	Panama	Solar	10	49 %	2H 2024
Esti Solar II	Panama	Solar	18	49 %	2H 2024
Rexford	US-CA	Solar	300	100 %	2H 2024-1H 2025
		Energy Storage	240		
Morris Solar	US-MO	Solar	250		1H 2025
Bellefield Phase 1 [1]	US-CA	Solar	500	75 %	2H 2025
		Energy Storage	500		
			3,366		

(1) Owned by ACED.

(2) Owned by AES Renewable Holdings.

AES Clean Energy

Business Description — AES' U.S. renewables portfolio, referred to as AES Clean Energy, is the leading U.S. renewables growth platform in serving large corporations with its 51 GW development pipeline. AES Clean Energy aims to solve customers' energy challenges by offering an expanded portfolio of innovative solutions based on cutting-edge technologies that are designed to accelerate customers' transitions to carbon-free energy. The generation capacity of the systems owned and/or operated under AES Clean Energy is 6,964 MW across the U.S., with another 3,121 MW under construction, including 1,725 MW of solar, 297 MW of wind, and 1,099 MW of energy storage. AES Clean Energy has a 6.1 GW backlog of projects, the majority of which are expected to come online through 2025. The adoption of the Inflation Reduction Act ("IRA") in 2022 and the expansion of data center needs related to the growing use of generative artificial intelligence are expected to be a significant accelerant to the growth of the U.S. renewables market and AES seeks to capture a significant portion of this market expansion.

AES Clean Energy comprises AES Renewable Holdings, sPower, ACED, and other renewable assets, as part of its broader investments in the U.S. ACED was formed on February 1, 2021, as specifically identified projects in the sPower and AES Renewable Holdings development platforms were merged. ACED serves as the development vehicle for all future renewables projects in the U.S. Following the merger, ACED expanded through the acquisitions of the Valcour Intermediate Holdings wind platform and Community Energy, a U.S. solar developer, as well as the acquisition of a small wind team and multiple development projects, most notably Bellefield in 2023. AES Clean Energy has also grown organically at a rapid pace and now has more than 1,300 employees, in contrast to less than 500 employees at the time of its formation in 2021 as it has expanded its capabilities and geographic reach to better serve the needs of the growing U.S. market. During the same time period, the development pipeline has also more than doubled.

In line with AES' strategy of using partnerships to promote the effective deployment of capital, in February 2023, the Company sold 49% of its indirect interest in a 1.3 GW portfolio of sPower's operating assets ("OpCo B") that includes 17 solar projects and one wind project, located across six states, to Hannon Armstrong Sustainable Infrastructure Capital, Inc. ("HASI"). Further, in December 2023, AES Renewable Holdings issued preferred shares in a portfolio of approximately 605 MW across 200 solar and solar plus storage assets ("OpCo 1") operating across eleven states to HASI.

Key Financial Drivers — The financial results of AES Clean Energy are primarily driven by the efficient construction and operation of renewable energy facilities across the U.S. under long-term PPAs, through which the energy price on the entire production of these facilities is determined. Tax credits associated with the development of U.S. renewables projects can be substantial and have increased with the adoption of the IRA. In 2023, AES recognized $611 million of pre-tax contribution related to the monetization of tax attributes to tax equity investors and transferability tax credit buyers relating to U.S. renewables projects,$18 million of which relates to a solar project owned by our utility at AES Indiana. The financial results of U.S. renewable assets are primarily driven by the amount of wind or solar resource at the facilities, availability of facilities, growth in projects, and by tax credit recognition once placed in service.

A majority of solar projects under AES Clean Energy have been financed with tax equity structures. Under these tax equity structures, the tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes, that vary over the life of the projects. Based on certain liquidation provisions of the tax equity structures, this could result in variability to earnings attributable to AES compared to the earnings reported at the facilities. In 2023, AES Clean Energy largely generated investment tax credits ("ITCs") from its renewable assets. We expect that the extension of the current ITCs and production tax credits ("PTCs"), as well as higher credits available for projects that satisfy wage and apprenticeship requirements under the IRA, will increase demand for our renewable products. Also in 2023, AES Clean Energy monetized tax credits under the transferability provisions of the IRA for the first time. These tax credit sales reduce our tax rate under U.S. GAAP.

Buffalo Gap I, Buffalo Gap II, and Buffalo Gap III are exposed to the volatility of energy prices and their revenue may change materially as energy prices fluctuate in their respective markets of operations. For these projects, ERCOT power prices impact financial results. The Alamitos Energy Storage Facility is a 100 MW interconnected battery-based energy storage facility located in California that operates under 20-year tolling agreements with Southern California Edison.

Development Strategy — As states, communities, and organizations of all types make commitments and plan to reduce their carbon footprints, renewables are the fastest-growing source of electricity generation in the U.S. AES Clean Energy works with its customers to co-create and deliver the smarter, greener energy solutions that meet their needs, including 24/7 carbon-free energy. For example, AES has worked with several major technology companies to provide clean energy solutions to power their network of data centers and we see these relationships growing as utilization of generative artificial intelligence drives the expansion of data center use.

In 2023, AES Clean Energy signed or was awarded 4,770 MW of PPAs. As of December 31, 2023, AES Clean Energy's renewables project backlog includes 6.1 GW of projects for which long-term PPAs have been signed or, as applicable, tariffs have been assigned through a regulatory process. The budget for construction of the projects currently under construction and the contracted projects is over $5 billion. The IRA includes increases, extensions, and/or new tax credits for onshore wind, solar, storage, and hydrogen projects. These changes in tax policy are supportive of our strategy to grow the AES Clean Energy business through development of our 51 GW U.S. pipeline.

AES Brasil

Business Description — AES Brasil is a publicly traded company in Brazil. AES controls and consolidates AES Brasil through its 47% economic interest. With an exclusive focus on renewable energy, AES Brasil has strategically positioned plants across the country to supply energy to customers and the regulated market. Leveraging hydro, solar, and wind generation, AES Brasil has been a key player in the Brazilian energy sector for nearly 25 years.

As a 100% renewable energy generator, AES Brasil holds a diversified portfolio and has expanded from an installed capacity of 2.7 GW in 2016 to 5.2 GW in 2023, which is composed by hydroelectric plants (2,658 MW) operating under a 33-year concession expiring in 2032, wind complexes (2,194 MW) and solar complexes (328 MW), equivalent to 52%, 42% and 6%, respectively. Among these, 5.1 GW are already operational and 113 MW are under construction.

AES Brasil aims to contract most of its physical guarantee requirements and sell the remaining portion in the spot market. The commercial strategy is reassessed periodically according to changes in market conditions, hydrology, and other factors. AES Brasil generally sells available energy through medium-term bilateral contracts.

Key Financial Drivers — The electricity market in Brazil is highly dependent on hydroelectric generation, therefore electricity pricing is driven by hydrology. AES Brasil owns 12 hydroelectric power plants in the state of São Paulo, which represents approximately 2% of the hydropower physical guarantee of the hydrological risk sharing system (Energy Reallocation Mechanism or "MRE", as described below in the topic *International Energy Markets and Regulatory Environment)*. Plant availability is also a significant financial driver as in times of high hydrology, AES is more exposed to the spot market. AES Brasil's financial results are driven by many factors, including, but not limited to:

- hydrology, impacting quantity of energy generated in the MRE;
- expansion in the demand for energy, especially considering the market opening in the years ahead;
- market price risk when re-contracting;
- effective asset management;
- efficient cost management; and
- successful execution on its growth strategy.

Development Strategy — AES Brasil's strategy is to grow by adding renewable capacity to its generation platform through acquisition or greenfield projects, to focus on client satisfaction and innovation to offer new products and energy solutions, and to be recognized for excellence in asset management.

Under the current terms of the 2018 legal agreement in connection with AES Brasil's concession with the state government, AES Brasil is required to increase its capacity in the state of São Paulo by an additional 28 MW by October 2024. On November 30, 2021, AES Brasil acquired AGV VII Solar project with an under construction installable capacity of 33 MW of solar generation, that is expected to be concluded in 2024.

AES Argentina

Business Description — AES operates plants in Argentina within the Renewables SBU totaling 1,407 MW, representing 3% of the country's total installed capacity, and AES Argentina's plants are placed in strategic locations within the country in order to provide energy to the spot market and customers.

AES primarily sells its energy in the wholesale electricity market where prices are largely regulated. In 2023, approximately 76% of the energy sold in the wholesale electricity market was produced by the hydropower plants, and 24% generated by the wind power plants.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- forced outages;
- exposure to fluctuations of the Argentine peso;
- timely collection of FONINVEMEM installments and outstanding receivables (see *International Energy Markets and Regulatory Environment* below);
- changes in hydrology and wind resources; and
- domestic energy demand and exports.

Development Strategy — AES Argentina has a pipeline of 753 MW of wind and solar greenfield projects in different stages of development. These projects are adjacent or nearby to AES Argentina's current operating assets and will be used to participate in future private auctions for renewable PPAs.

AES Colombia

Business Description — We operate in Colombia through AES Colombia, a subsidiary of AES Andes, which owns Chivor, a hydroelectric plant with an installed capacity of 1,000 MW and Tunjita, a 20 MW run-of-river hydroelectric plant, both located approximately 100 miles east of Bogota, as well as the solar facilities of Castilla, Brisas, and San Fernando, 21 MW, 27 MW, and 61 MW respectively. AES Colombia’s installed capacity accounted for approximately 6% of system capacity at the end of 2023. AES Colombia is dependent on hydrological conditions, which influence generation and spot prices of non-contracted generation in Colombia.

AES Colombia's commercial strategy aims to execute contracts with commercial and industrial customers and bid in public tenders, mainly with distribution companies, in order to reduce margin volatility with proper portfolio risk management. The remaining energy generated by our portfolio is sold to the spot market, including ancillary services. Additionally, AES Colombia receives reliability payments for maintaining the plant's availability and generating firm energy during periods of power scarcity, such as adverse hydrological conditions, in order to prevent power shortages.

Key Financial Drivers — Hydrological conditions largely influence Chivor's power generation. Maintaining the appropriate contract level, while maximizing revenue through the sale of excess generation, is key to AES Colombia's results of operations. In addition to hydrology, financial results are driven by many factors, including, but not limited to:

- forced outages;
- fluctuations of the Colombian peso; and
- spot market prices.

Development Strategy — AES Colombia is committed to supporting its customers to diversify their energy supply and become more competitive. As part of this commitment, AES Colombia is developing a pipeline of 1.3 GW of solar and wind projects. Six wind projects totaling 1,149 MW are located in La Guajira, one of the windiest spots in the world. Of the 1,149 MW, 255 MW were awarded a 15-year PPAs in the renewable auction in 2019.

AES Panama

Business Description — AES owns and operates five hydroelectric plants totaling 705 MW of generation capacity, a wind farm of 55 MW and four solar plants of 10 MW each, which collectively represent 20% of the total installed capacity in Panama.

The majority of our hydroelectric plants in Panama are based on run-of-the-river technology, with the exception of 223 MW Changuinola plant with regulation reservoirs and the 260 MW Bayano plant. Hydrological conditions have an important influence on profitability. Variations in hydrology can result in an excess or a shortfall in energy production relative to our contractual obligations. Hydro generation is generally in a shortfall position during the dry season from January through May, which is offset by thermal and wind generation since its behavior is opposite and complementary to hydro generation.

Our hydro assets are mainly contracted through medium to long-term PPAs with distribution companies, while a small volume of our hydro plants are contracted with unregulated users. Our hydro assets in Panama have PPAs with distribution companies expiring up to December 2030 for a total contracted capacity of 350 MW.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- changes in hydrology, which impacts spot prices and exposes the business to variability in the cost of replacement power;
- fluctuations in commodity prices, mainly fuel oil and natural gas, which affect the cost of thermal generation and spot prices;
- constraints imposed by the capacity of transmission lines connecting the west side of the country with the load, keeping surplus power trapped during the rainy season; and
- country demand as GDP growth is expected to remain stable over the short and medium term.

Development Strategy — AES is investing in renewables projects within the region. This will increase complementary non-hydro renewable assets in the system and contribute to the reduction of hydrological risk in Panama.

AES Mexico

Business Description — Mesa La Paz is a 306 MW wind project developed under a joint venture with Grupo

Bal, located in Llera, Tamaulipas. Mesa La Paz sells 72% of its power under long-term PPAs expiring up to 2045.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- contracting levels, providing additional benefits from improved operational performance, including performance incentives and/or excess energy sales;
- changes in the methodology to calculate spot energy prices or Locational Marginal Prices, which impacts the excess energy sales;
- improved operational performance and plant availability; and
- changes in wind resources.

Development Strategy — AES has partnered with Grupo Bal in a joint venture to co-invest in power and related infrastructure projects in Mexico, focusing on renewable generation.

AES Bulgaria

Business Description — AES owns an 89% economic interest in the St. Nikola wind farm ("Kavarna") with 156 MW of installed capacity. The power output of St. Nikola is sold to customers operating on the liberalized electricity market and the plant may receive additional revenue per the terms of an October 2018 Contract for Premium with the state-owned Electricity System Security Fund.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- regulatory changes in the Bulgarian power market;
- availability and load factor of the operating units;
- the level of wind resources; and
- spot market price volatility beyond the level of compensation through the Contract for Premium.

In December 2022, Bulgaria implemented Regulation 2022/1854, approved by the European Council in October 2022 as an emergency intervention aiming at limiting energy prices in Europe. The main measure of interest to AES in Bulgaria is the limitation of revenues for "infra-marginal" producers, a category that includes renewables and other technologies which are providing electricity to the grid at a cost below the price level set by the more expensive “marginal” producers. For renewable plants such as Kavarna which are operating under a Contract for Premium, the regulation essentially captures 90% of the incremental margin of the wind farm when wholesale prices are above their original Feed in Tariff of €96.27/MWh. This regulation has been extended until the end of 2024 by the Bulgarian Parliament.

AES Dominicana

Business Description — AES Dominicana has three operating subsidiaries within the Renewables SBU, each of which are owned 65% by AES. Bayasol owns and operates a 50 MW solar farm, Santanasol operates a 50 MW solar farm, and Agua Clara operates a 50 MW wind farm.

AES has a strategic partnership with the Estrella and Linda Groups ("Estrella-Linda"), a consortium of two leading Dominican industrial groups that manage a diversified business portfolio. In December 2023, AES completed the sale of an additional 10% ownership interest in AES Dominicana to the existing partners and a 10% interest to Grupo Popular's subsidiary, AFI Popular, selling 20% ownership interest in total. After this transaction, AES' ownership interest in AES Dominicana is 65%.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- change in wind and solar resources due to heavy rains, hurricanes and other natural events that may affect the country;
- constraints imposed by the capacity of transmission lines and potential delays on the transmission expansion projects; and
- related to projects under construction, changes in execution cost and scope of work that may delay the operation of the new renewable plants.

AES Puerto Rico

Business Description — AES Puerto Rico owns and operates Ilumina, a 24 MW solar facility in Puerto Rico. The plant is fully contracted through a long-term PPA with PREPA expiring in 2037. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—*

Macroeconomic and Political—Puerto Rico for further discussion of the long-term PPAs with PREPA.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to, operational performance and plant availability.

Development Strategy — Puerto Rico has clear goals of supplying its system from renewable resources, with targets of 40% from renewables by 2025 and 100% by 2050. To achieve the established target of 40%, PREPA intends to launch six tender processes for renewable generation in the coming years. Clean Flexible Energy LLC, the legal entity that AES is utilizing to develop renewables in Puerto Rico, expects to have a portfolio of solar and energy storage projects participating. On November 30, 2023, for the first tender process, Clean Flexible Energy, LLC and PREPA closed solar plus storage agreements for a total of 400 MW, which must reach COD within 24 months.

AES Jordan

Business Description — In Jordan, AES has a 36% controlling interest in a 48 MW solar plant fully contracted with the national utility under a 20-year PPA expiring in 2039. We consolidate the results in our operations as we have a controlling interest in this business.

Utilities

Business Overview

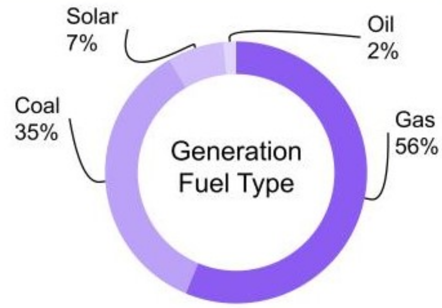
11 Generation Facilities

6 Utility Companies

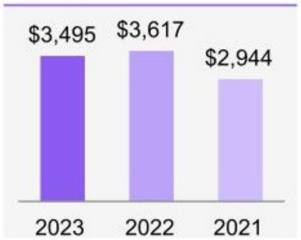
3,500 Gross MW

31,725 GWH

Key Utilities: **AES Indiana, AES Ohio, and AES El Salvador**



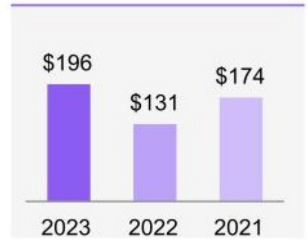
Revenue
(In millions)



Operating Margin
(in millions)

Adjusted EBITDA [(1)]
(in millions)

Adjusted PTC [(1)]
(in millions)



Key events in 2023

- AES Indiana reached a settlement agreement for its first rate case since 2018
- AES Ohio received approval from the PUCO for its Electric Security Plan (ESP4)
- Retired 415 MW of coal at Petersburg Unit 2 at AES Indiana

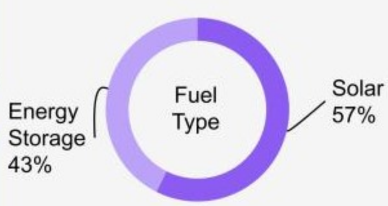
Strategic outlook

- AES Indiana expects to receive approval of its rate case from the IURC by the middle of 2024
- Total backlog of 0.7 GW of renewables under signed long-term PPAs
- Expect to convert remaining two coal units of Petersburg to natural gas

Under construction

3 Plants

575 MW



Contracted renewable backlog

106 MW

Signed PPAs not yet under construction

(1) Non-GAAP measure. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—SBU Performance Analysis—Non-GAAP Measures* for reconciliation and definition.

Utilities

Our Utilities SBU is the second largest contributor to our future growth, particularly in the U.S., where we are targeting a combined 10% annual growth in rate base at our two utilities: AES Indiana and AES Ohio. In this segment, we also have four utilities in El Salvador and a portfolio of generation facilities, including at our integrated utility in Indiana, with installed operating capacity of 3,500 MW. IPALCO (AES Indiana's parent), AES Ohio, and DPL Inc. (AES Ohio's parent) are all SEC registrants, and as such, follow the public filing requirements of the Securities Exchange Act of 1934.

Utilities — The following table lists our utilities and their generation facilities:

Business	Location	Type	AES Equity Interest	Approximate Number of Customers Served as of 12/31/2023	Approximate GWh Sold in 2023	Fuel	Gross MW	Year Acquired or Began Operation
CAESS	El Salvador	Distribution	75 %	659,000	2,214			2000
CLESA	El Salvador	Distribution	80 %	475,000	1,143			1998
DEUSEM	El Salvador	Distribution	74 %	95,000	174			2000
EEO	El Salvador	Distribution	89 %	357,000	762			2000
El Salvador Subtotal				**1,586,000**	**4,293**			
AES Ohio [1]	US-OH	Transmission & Distribution	100 %	539,000	13,305			2011
AES Indiana [2]	US-IN	Integrated	70 %	523,000	14,127	Coal/Gas/ Oil/Solar/ Energy Storage	3,357	2001
United States Subtotal				**1,062,000**	**27,432**		**3,357**	
				2,648,000	**31,725**			

(1) AES Ohio's GWh sold in 2023 represent total transmission and distribution sales. AES Ohio's wholesale sales and SSO utility sales, which are sales to utility customers who use AES Ohio to source their electricity through a competitive bid process, were 3,183 GWh in 2023. AES Ohio owns a 4.9% equity ownership in OVEC, an electric generating company. OVEC has two plants in Cheshire, Ohio and Madison, Indiana with a combined generation capacity of approximately 2,109 MW. AES Ohio's share of this generation is approximately 103 MW.

(2) CDPQ owns direct and indirect interests in IPALCO (AES Indiana's parent) which total approximately 30%. AES owns 85% of AES US Investments and AES US Investments owns 82.35% of IPALCO. AES Indiana plants: Georgetown, Harding Street, Petersburg and Eagle Valley. 20 MW of AES Indiana total is considered a transmission asset. In December 2023, the first stage of construction for the 195 MW Hardy Hills solar project was completed and initial operations for over half of the project commenced. The remaining MW are expected to be placed in service in 2024.

Generation — The following table lists our Utilities SBU generation facilities. The energy produced by these generation facilities is fully contracted by AES' utilities in El Salvador.

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Bosforo [1]	El Salvador	Solar	100	50 %	2018-2019	2043-2044	CAESS, EEO, CLESA, DEUSEM
Metapan	El Salvador	Solar	15	100 %	2043-2048	2033	CLESA, Cemento Holcim de El Salvador
Cuscatlan Solar [1]	El Salvador	Solar	10	50 %	2021	2046	CLESA
AES Nejapa	El Salvador	Landfill Gas	6	100 %	2011	2035	CAESS
Meangura del Gofo	El Salvador	Solar	1	100 %	2023	2048	EEO
		Energy Storage	4				
Opico	El Salvador	Solar	4	100 %	2020	2040	CLESA
Moncagua	El Salvador	Solar	3	100 %	2015	2035	EEO
			143				

(1) Unconsolidated entity, accounted for as an equity affiliate.

Under construction — The following table lists our plants under construction in the Utilities SBU:

Business	Location	Fuel	Gross MW	AES Equity Interest	Expected Date of Commercial Operations
Hardy Hills Solar (AES Indiana) [1]	US-IN	Solar	80	70 %	1H 2024
Pike County (AES Indiana)	US-IN	Energy Storage	200	70 %	2024
Petersburg Energy Center (AES Indiana)	US-IN	Solar	250	70 %	2H 2025
		Energy Storage	45		
			575		

(1) In December 2023, the first stage of construction of this project was completed and initial operations for over half of the project commenced. The final stage of construction is expected to be completed during the first half of 2024.

AES Indiana

Business Description — IPALCO is a holding company whose principal subsidiary is AES Indiana. AES Indiana is an integrated utility that is engaged primarily in generating, transmitting, distributing, and selling electric energy to retail customers in the city of Indianapolis and neighboring areas within the state of Indiana and is subject to regulatory authority—see *Regulatory Framework and Market Structure* below. AES Indiana has an exclusive right to provide electric service to the customers in its service area, covering about 528 square miles with an estimated population of approximately 969,000 people.

AES Indiana owns and operates four generating stations, all within the state of Indiana. The first station, Petersburg, is coal-fired, and consists of four units. AES Indiana retired 230 MW Petersburg Unit 1 in May 2021 and 415 MW Petersburg Unit 2 in June 2023, which resulted in 630 MW of total retired economic capacity at this station. AES Indiana plans to convert the remaining two coal units at Petersburg to natural gas (see *Integrated Resource Plan* below). The second station, Harding Street, consists of three natural gas-fired boilers and steam turbines and uses natural gas and fuel oil to power five combustion turbines. In addition, AES Indiana operates a 20 MW battery-based energy storage unit at this location, which provides frequency response. The third station, Eagle Valley, is a CCGT natural gas plant. The fourth station, Georgetown, is a small peaking station that uses natural gas to power combustion turbines. In addition, AES Indiana helps meet its customers' energy needs with long-term contracts for the purchase of 300 MW of wind-generated electricity and 94 MW of solar-generated electricity.

In December 2021, AES Indiana completed the acquisition of Hardy Hills Solar Energy LLC, including the development of a 195 MW solar project (the "Hardy Hills solar project"). In December 2023, the first stage of construction for the Hardy Hills solar project was completed and initial operations for over half of the project commenced. The final stage of construction of the project is expected to be completed during the first half of 2024.

In August 2023, AES Indiana completed the acquisition of Petersburg Energy Center, LLC, including the development of a 250 MW solar and 45 MW (180 MWh) energy storage facility (the "Petersburg Energy Center project"). The Petersburg Energy Center project is expected to be completed in 2025.

In June 2023, AES Indiana executed an agreement for the construction of the 200 MW (800 MWh) Pike County BESS project to be developed at the AES Indiana Petersburg Plant site in Pike County, Indiana, subject to IURC approval, which was received in January 2024. The Pike County BESS project is expected to be completed in 2024.

In July 2023, AES Indiana executed a purchase agreement for the acquisition of the Hoosier Wind Project, which is an existing 106 MW wind facility located in Benton County, Indiana, subject to IURC approval, which was received in January 2024. The acquisition of the Hoosier Wind Project is expected to be completed in the first quarter of 2024.

Key Financial Drivers — AES Indiana's financial results are driven primarily by retail demand, weather, and maintenance costs. In addition, AES Indiana's financial results are likely to be driven by many other factors including, but not limited to:

- regulatory outcomes and impacts;
- the passage of new legislation, implementation of regulations, or other changes in regulation; and
- timely recovery of capital expenditures and operation and maintenance costs.

Regulatory Framework and Market Structure — AES Indiana is subject to comprehensive regulation by the IURC with respect to its services and facilities, retail rates and charges, the issuance of long-term securities, and certain other matters. The regulatory authority of the IURC over AES Indiana's business is typical of regulation generally imposed by state public utility commissions. The IURC sets tariff rates for electric service provided by AES Indiana. The IURC considers all allowable costs for ratemaking purposes, including a fair return on assets used and useful to providing service to customers.

AES Indiana's tariff rates for electric service to retail customers consist of basic rates and approved charges. In addition, AES Indiana's rates include various adjustment mechanisms, including, but not limited to: (i) a rider to reflect changes in fuel and purchased power costs to meet AES Indiana's retail load requirements, referred to as the Fuel Adjustment Charge, (ii) a rider for the timely recovery of costs incurred to comply with environmental laws and regulations, including a return, (iii) a rider to reflect changes in ongoing RTO costs, (iv) riders for passing through to customers wholesale sales margins and capacity sales above and below established annual benchmarks, (v) a rider for a return on, and of, investments for eligible TDSIC improvements, and (vi) a rider for cost recovery, lost margin recoveries and performance incentives from AES Indiana's demand side management energy efficiency programs. Each of these tariff rate components function somewhat independently of one another, but the overall structure of AES Indiana's rates is subject to review at the time of any review of AES Indiana's basic rates and charges. Additionally, AES Indiana's rider recoveries are reviewed through recurring filings.

AES Indiana filed a petition with the IURC on June 28, 2023, for authority to increase its basic rates and charges to cover the rising operational costs and needs associated with continuing to serve its customers safely and reliably. The factors leading to AES Indiana's first base rate increase request in five years include inflationary impacts on operations and maintenance expenses, investments in the transmission and distribution systems, and modernization of its customer systems. AES Indiana is also seeking recovery of increased costs to support its vegetation management plan, which covers the removal of overhang and tree trimming in its service territory. AES Indiana also seeks to better align depreciation expense with the period in which the generation plants provide service to customers and remove operational costs of the retired Petersburg units from rates. On November 22, 2023, AES Indiana entered into a unanimous stipulation and settlement agreement (the "settlement") with the OUCC and the intervening parties which, if approved by the IURC, would increase its annual revenue requirement by $73 million. AES Indiana expects to receive an order from the IURC and place new rates into effect by the end of the second quarter of 2024.

On October 31, 2018, the IURC issued an order approving an uncontested settlement agreement to increase AES Indiana's annual revenues by $44 million, or 3% (the "2018 Base Rate Order"), which are the base rates under which AES Indiana is currently operating. This revenue increase primarily includes recovery through rates of costs associated with the CCGT at Eagle Valley, completed in the first half of 2018, and other construction projects. New base rates and charges became effective on December 5, 2018.

AES Indiana is one of many transmission system owner members in MISO, an RTO which maintains functional control over the combined transmission systems of its members and manages one of the largest energy and ancillary services markets in the U.S. MISO dispatches generation assets in economic order considering transmission constraints and other reliability issues to meet the total demand in the MISO region. AES Indiana offers electricity in the MISO day-ahead and real-time markets.

Development Strategy — AES Indiana's construction program is composed of capital expenditures necessary for prudent utility operations and compliance with environmental regulations, along with discretionary investments designed to replace aging equipment or improve overall performance.

Senate Enrolled Act 560, the Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") statute, provides for cost recovery outside of a base rate proceeding for new or replacement electric and gas transmission, distribution, and storage projects that a public utility undertakes for the purposes of safety, reliability, system modernization, or economic development. Provisions of the TDSIC statute require that requests for recovery include a plan of at least five years and not more than seven for eligible investments. Once a plan is approved by the IURC, eighty percent of eligible costs can be recovered using a periodic rate adjustment mechanism, referred to as a TDSIC mechanism. Recoverable costs include a return on, and of, the investment, including AFUDC, post-in-service carrying charges, operation and maintenance expenses, depreciation, and property taxes. The remaining twenty percent of recoverable costs are deferred for future recovery in the public utility’s next base rate case. The TDSIC mechanism is capped at an annual increase of two percent of total retail revenues.

On March 4, 2020, the IURC issued an order approving the projects in AES Indiana's seven-year TDSIC Plan for eligible transmission, distribution, and storage system improvements totaling $1.2 billion from 2020 through 2026. Beginning in June 2020, AES Indiana files an annual TDSIC rate adjustment for a return on, and of, investments through March 31 with rates requested to be effective each November. Annual TDSIC plan update filings are required to be staggered by six months as ordered by the IURC and are filed each December. The total amount of AES Indiana’s equipment net of depreciation, including carrying cost, approved for TDSIC recovery as of December 31, 2023 was $400 million.

Integrated Resource Plan — In December 2022, AES Indiana filed its Integrated Resource Plan ("IRP"), which describes AES Indiana's Preferred Resource Portfolio for meeting generation capacity needs for serving AES Indiana's retail customers over the next several years. The Preferred Resource Portfolio is AES Indiana's reasonable least cost option and provides a cleaner and more diverse generation mix for customers. The 2022 IRP short-term action plan includes converting the two remaining coal units at Petersburg to natural gas. AES Indiana has not yet filed for the regulatory approvals from the IURC to convert Petersburg units 3 and 4, however, AES Indiana expects to do so at the appropriate time. Additionally, AES Indiana plans to add up to 1,300 MW of wind, solar, and battery energy storage by 2027. As new technologies, such as green hydrogen, small modular reactors, and carbon capture are developed and cost effective, we will evaluate them in the future planning processes.

AES Indiana expects to spend an estimated $3.2 billion on capital projects from 2024 through 2026, which includes AES Indiana's power generation and renewable energy projects discussed above, spending under AES Indiana's TDSIC Plan, as well as other new transmission and distribution projects.

In December 2021 and 2022, AES Indiana received equity capital contributions of $275 million and $253 million, respectively, from AES and CDPQ on a proportional share basis to be used for funding needs related to AES Indiana’s TDSIC and replacement generation projects.

AES Ohio

Business Description — DPL is a holding company whose principal subsidiary is AES Ohio. AES Ohio is a utility company that transmits and distributes electricity to approximately 539,000 retail customers in a 6,000 square mile area of West Central Ohio and is subject to regulatory authority—see *Regulatory Framework and Market Structure* below. AES Ohio has the exclusive right to provide transmission and distribution services to its customers, and procures retail standard service offer ("SSO") electric service on behalf of residential, commercial, industrial, and governmental customers through a competitive bid auction process.

Key Financial Drivers — AES Ohio's financial results are driven primarily by retail demand and weather. AES Ohio's financial results are likely to be driven by other factors as well, including, but not limited to:

- regulatory outcomes and impacts;
- the passage of new legislation, implementation of regulations, or other changes in regulations; and
- timely recovery of transmission and distribution expenditures.

Regulatory Framework and Market Structure — AES Ohio is regulated by the PUCO for its distribution services and facilities, retail rates and charges, reliability of service, compliance with renewable energy portfolio requirements, energy efficiency program requirements, and certain other matters. The PUCO maintains jurisdiction over the delivery of electricity, SSO, and other retail electric services.

Electric customers within Ohio are permitted to purchase power under contract from a Competitive Retail Electric Service ("CRES") provider or from their local utility under SSO rates. The SSO generation supply is provided by third parties through a competitive bid process. Ohio utilities have the exclusive right to provide transmission and distribution services in their state-certified territories. While Ohio allows customers to choose retail generation providers, AES Ohio is required to provide retail generation service at SSO rates to any customer that has not signed a contract with a CRES provider or as a provider of last resort in the event of a CRES provider default. SSO rates are subject to rules and regulations of the PUCO and are established through a competitive bid process for the supply of power to SSO customers.

AES Ohio's distribution rates are regulated by the PUCO and are established through a traditional cost-based rate-setting process. AES Ohio is permitted to recover its costs of providing distribution service as well as earn a regulated rate of return on assets, determined by the regulator, based on the utility's allowed regulated asset base, capital structure, and cost of capital. AES Ohio's retail rates include various adjustment mechanisms including, but not limited to, the timely recovery of costs incurred related to power purchased through the competitive bid process, participation in the PJM RTO, severe storm damage, and energy efficiency.

The costs associated with providing high voltage transmission service and wholesale electric sales and ancillary services are subject to FERC jurisdiction. AES Ohio implemented a formula-based rate for its transmission service, effective May 3, 2020.

AES Ohio is a member of PJM, an RTO that operates the transmission systems owned by utilities operating in all or parts of a multi-state region, including Ohio. PJM also administers the day-ahead and real-time energy markets, ancillary services market and forward capacity market for its members.

Ohio law requires utilities to file either an Electric Security Plan ("ESP") or MRO plan to establish SSO rates. AES Ohio is currently operating pursuant to ESP 4, described in the paragraph below. From November 1, 2017 through December 18, 2019, AES Ohio operated pursuant to an approved ESP plan, which was initially approved in October, 2017 (ESP 3). On December 18, 2019, the PUCO approved AES Ohio's Notice of Withdrawal and reversion to its prior rate plan (ESP 1). Among other items, the PUCO Order approving the ESP 1 rate plan includes reinstating the non-bypassable RSC Rider, which provides annual revenues of approximately $79 million. The Office of the Ohio Consumers' Council ("OCC") has appealed to the Ohio Supreme Court, the Commission's decision approving the reversion to ESP 1 as well as argued for a refund of the Rate Stabilization Charge ("RSC") revenues dating back to August 2021. A decision is pending regarding this appeal, which has been consolidated with the appeal regarding the Smart Grid Comprehensive Settlement described in the paragraph below. We are unable to predict the outcome of this appeal, but if this results in terms that are more adverse than AES Ohio's current ESP rate plan, it could have a material adverse effect on our results of operations, financial condition and cash flows.

Smart Grid Comprehensive Settlement — In October 2020, AES Ohio entered into a Stipulation and Recommendation (settlement) with the staff of the PUCO and various customers, and organizations representing customers of AES Ohio and certain other parties with respect to, among other matters, AES Ohio's applications pending at the PUCO for (i) approval of AES Ohio's plan to modernize its distribution grid ("Smart Grid Phase 1"), (ii) findings that AES Ohio passed the Significantly Excessive Earnings Test ("SEET") for 2018 and 2019, and (iii) findings that AES Ohio's current ESP 1 satisfies the SEET and the more favorable in the aggregate ("MFA") regulatory test. In June 2021, the PUCO issued their opinion and order accepting the stipulation as filed. With the PUCO's issuance of their opinion and order, AES made cash contributions of $150 million in 2021 to improve AES Ohio's infrastructure and modernize its grid while maintaining liquidity. The OCC appealed this final PUCO Order to the Ohio Supreme Court in December 2021; this appeal remains pending.

In February 2024, AES Ohio filed a Smart Grid Phase 2 with the PUCO proposing to invest approximately $683 million in capital projects over a 10-year period following the Smart Grid Phase 1, which ends June 2025. There are three principal components of AES Ohio's Smart Grid Phase 2: 1) Distribution Operations, 2) Advanced Intelligence 3) Telecommunications and Cybersecurity. These initiatives will also allow AES Ohio to be ready to leverage and integrate Distributed Energy Resources into its grid. If approved, AES Ohio will implement a comprehensive grid modernization project that will deliver benefits to customers, society as a whole and to AES Ohio. A procedural schedule is expected that will provide for an Order by the second quarter of 2025 prior to the end of Smart Grid Phase 1.

On September 26, 2022, AES Ohio filed its latest ESP ("ESP 4") with the PUCO. ESP 4 is a comprehensive plan to enhance and upgrade its network and improve service reliability, provide greater safeguards for price stability and continue investments in local economic development. In April 2023, AES Ohio entered into a Stipulation and Recommendation with the PUCO Staff and seventeen parties (the "Settlement") with respect to AES Ohio's ESP 4 application, and, in August, 2023, the PUCO approved the Settlement without modification. The Settlement provides for a three-year ESP without a rate stability charge, and, in addition to other items, provides for (i) a Distribution Investment Rider for the term of the ESP allowing for the timely recovery of distribution investments by AES Ohio based on a 9.999% return on equity, subject to revenue caps, (ii) recovery of approximately $66 million related to past expenditures by AES Ohio plus future carrying costs and the recovery of incremental vegetation management expenses up to certain annual limits during the term of ESP 4; and (iii) funding of programs for assistance to low-income customers and for economic development. With approval of this Settlement, the distribution rates that were approved by the PUCO in December 2022, and are described in the paragraph below, became effective on September 1, 2023.

In November, 2020, AES Ohio filed a new distribution rate case application with the PUCO to increase AES Ohio's base rates for electric distribution service to address, in part, increased costs of materials and labor and substantial investments to improve distribution structures. In December, 2022, the PUCO issued an order on the application. Among other matters, the order (i) establishes a revenue increase of $76 million for AES Ohio's base rates for electric distribution service and (ii) provides for a return on equity of 9.999% and a cost of long-term debt of

4.4% on a rate base of $783 million and based on a capital structure of 53.87% equity and 46.13% long-term debt. These rates went into effect on September 1, 2023 with the approval of AES Ohio’s ESP 4.

Development Strategy — Planned construction projects primarily relate to new investments in and upgrades to AES Ohio's transmission and distribution system. Capital projects are subject to continuing review and are revised in light of changes in financial and economic conditions, load forecasts, legislative and regulatory developments, and changing environmental standards, among other factors.

AES Ohio is projecting to spend an estimated $1.2 billion on capital projects from 2024 through 2026, which includes expected spending under AES Ohio's Smart Grid Phase 1 included in the Stipulation and Recommendation entered into in October 2020 (see *Regulatory Framework and Market Structure* above) as well as other new transmission and distribution projects.

AES El Salvador

Business Description — AES El Salvador is the majority owner of four of the five distribution companies operating in El Salvador (CAESS, CLESA, EEO and DEUSEM). AES El Salvador's territory covers 77% of the country and accounted for 4,293 GWh of the market energy sales during 2023. AES El Salvador owns and operates four solar farms, Opico Power, Moncagua, and Metapan with 4 MW, 3 MW and 15 MW of capacity, respectively; Meanguera del Golfo, a solar and battery storage facility with 0.6 MW capacity; AES Nejapa, a biomass power plant with 6 MW capacity; and 50% of Bosforo and Cuscatlan Solar, solar farms with 100 MW and 10 MW capacity, respectively. The energy produced by these solar farms is fully contracted by AES' utilities in El Salvador.

In addition, AES El Salvador offers customers non-regulated services such as energy trading, electromechanical construction, O&M of electrical assets, EPC, pole rental, and tax collection for municipalities.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- operational performance;
- regulatory outcomes and impacts;
- variability in energy demand driven by weather; and
- the impact of fuel oil prices on energy tariff prices, which affect cash flow due to a three-month delay in the pass-through of energy costs to the tariffs charged to customers.

Development Strategy — In order to explore new business opportunities, AES El Salvador created AES Soluciones, an LED public lighting service provider and the main commercial and industrial solar photovoltaic EPC provider in the country. Electromobilty is also being promoted by AES Soluciones through a partnership with Blink Charger in order to design and deploy a private network of electric chargers throughout the country. AES Next, Ltda de. C.V. is the O&M services provider for the Bosforo project, as well as a developer of solar MW in El Salvador. Furthermore, the four distribution companies operated by AES El Salvador started a digitization and modernization initiative as part of the development, sustainability, and growth strategy of the business.

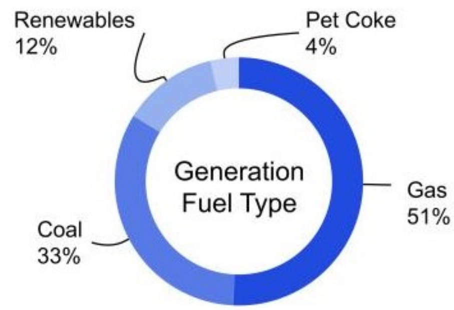
Energy Infrastructure

Business Overview

46 Generation Facilities

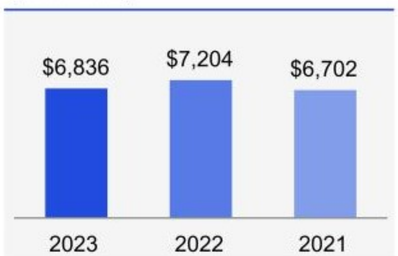
14,885 Gross MW

Key Generation Businesses: **AES Andes, Southland, AES Argentina, Mong Duong**, **Maritza, and Andres-Los Mina**

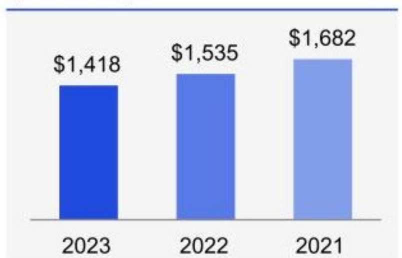


Note: All renewables in the Energy Infrastructure SBU are located in Chile.

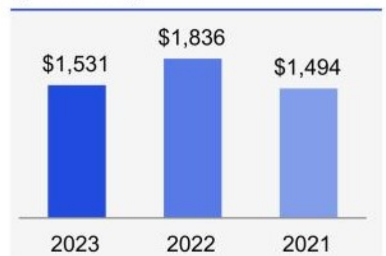
Revenue
(In millions)



Operating Margin
(in millions)



Adjusted EBITDA [(1)]
(in millions)



Key events in 2023

- Exited or announced the sale or closure of 1.7 GW of coal generation
- Signed agreements for three-year extensions of 1.4 GW of gas generation at the Southland legacy units in Southern California

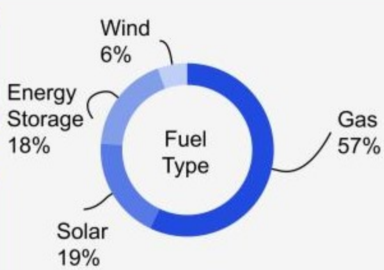
Strategic outlook

- Total backlog of 3.6 GW of renewables and gas under signed long-term PPAs, including 3 GW of renewables in Chile
- Intend to exit majority of coal businesses by year-end 2025[2]

Under construction

4 Plants

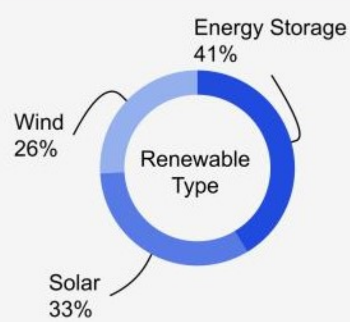
1,175 MW



Contracted renewable backlog

2,458 MW

Signed PPAs not yet under construction



(1) Non-GAAP measure. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—SBU Performance Analysis—Non-GAAP Measures* for reconciliation and definition.

(2) Through asset sales, fuel conversions and retirements, while maintaining reliability and affordability, and subject to necessary approvals. AES may delay the exit of a few select plants through 2027 to support continued electricity reliability.

Energy Infrastructure

Our Energy Infrastructure SBU aims to provide energy security to enable the integration of new renewables, maximize the value of our gas generation and LNG business through flexible operations that support the energy transition, and exit coal generation to achieve our decarbonization targets. This segment comprises generation facilities, using natural gas, LNG, coal, pet coke, diesel, and/or oil, in nine countries — Vietnam, the United States, Argentina, Chile, Bulgaria, Mexico, Jordan, Panama and the Dominican Republic. Although our businesses in Chile have a mix of generation sources, including renewables, the generation from all sources is pooled to service our existing PPAs. Consequently all of Chile's generation is included within the Energy Infrastructure SBU.

Generation — Operating installed capacity of our Energy Infrastructure segment totals 14,885 MW. The following table lists our Energy Infrastructure segment generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Mong Duong 2 (1)	Vietnam	Coal	1,242	51 %	2015	2040	EVN
Southland—Alamitos	US-CA	Gas	1,200	100 %	1998	2026	California Department of Water Resources
Paraná-GT	Argentina	Gas/Diesel	870	100 %	2001		
Southland Energy—Huntington Beach (3)	US-CA	Gas	694	50 %	2020	2040	Southern California Edison
Southland Energy—Alamitos (3)	US-CA	Gas	693	50 %	2020	2040	Southern California Edison
San Nicolás	Argentina	Coal/Gas/Oil/Energy Storage	691	100 %	1993		
Maritza	Bulgaria	Coal	690	100 %	2011	2026	National Electric Company (NEK)
TermoAndes (4)	Argentina	Gas/Diesel	643	99 %	2000	2024-2025	Various
Guillermo Brown (5)	Argentina	Gas/Diesel	576	— %	2016		
Angamos	Chile	Coal	558	99 %	2011		Various
Cochrane	Chile	Coal	550	57 %	2016	2030-2037	SQM, Sierra Gorda, Quebrada Blanca
Ventanas	Chile	Coal	537	99 %	2010, 2013		
Alto Maipo (2)	Chile	Hydro	531	99 %	2021	2040	Minera Los Pelambres
AES Puerto Rico	US-PR	Coal	524	100 %	2002	2027	LUMA Energy
Merida III	Mexico	Gas/Diesel	505	75 %	2000	2025	Comision Federal de Electricidad
Amman East (6)	Jordan	Gas	472	37 %	2009	2033	National Electric Power Company
Colon (7)	Panama	Gas	381	65 %	2018	2028	ENSA, Edemet, Edechi
DPP (Los Mina)	Dominican Republic	Gas	358	65 %	1996	2025	Ede Este, Ede Norte, Ede Sur, Non-Regulated Users
Andres (8)	Dominican Republic	Gas/Diesel	319	65 %	2003	2025	Ede Este, Ede Norte, Ede Sur, Non-Regulated Users
Andes 2b	Chile	Solar	180	99 %	2023		Various
		Energy Storage	112				
Norgener	Chile	Coal	276	99 %	2000	2028	Codelco
Termoelectrica del Golfo (TEG)	Mexico	Pet Coke	275	99 %	2007	2027	CEMEX
Termoelectrica del Penoles (TEP)	Mexico	Pet Coke	275	99 %	2007	2027	Peñoles
IPP4 (6)	Jordan	Gas	250	36 %	2014	2039	National Electric Power Company
Cordillera Hydro Complex (9)	Chile	Hydro	240	99 %	2000	2042	Various
Southland—Huntington Beach	US-CA	Gas	236	100 %	1998	2026	California Department of Water Resources
Warrior Run (10)	US-MD	Coal	205	100 %	2000	2024	Potomac Edison
Bolero	Chile	Solar	146	99 %	2023	2030	Various
Los Olmos	Chile	Wind	110	51 %	2022	2032	Google, Various
Los Cururos	Chile	Wind	109	51 %	2019		Various
Andes Solar 2a	Chile	Solar	81	51 %	2021		Google, Various

Mesamávida	Chile	Wind	68	51 %	2022	2038	Google, Various
Campo Lindo	Chile	Wind	65	51 %	2023		Various
Virtual Reservoir 2	Chile	Energy Storage	50	99 %	2023		
Sarmiento	Argentina	Gas/Diesel	33	100 %	1996		
Andes Solar 4	Chile	Solar	13	99 %	2023		Google, Various
		Energy Storage	13				
Andes Solar 1	Chile	Solar	22	99 %	2016	2036	Quebrada Blanca
Cochrane ES	Chile	Energy Storage	20	57 %	2016		
Angamos ES	Chile	Energy Storage	20	99 %	2011		
San Matias	Chile	Wind	17	99 %	2023	2038	Microsoft
Laja	Chile	Biomass	13	99 %	2000	2023	CMPC
Andes	Chile	Energy Storage	12	99 %	2009		
Alfalfal Virtual Reservoir	Chile	Energy Storage	10	99 %	2020		
PFV Kaufmann	Chile	Solar	1	99 %	2021	2040	Kaufmann
			14,885				

(1) In November 2023, agreed to sell this business to Sev.en Global Investments Pty Ltd. Following approvals by the Government of Vietnam and the Ministry of Industry and Trade, the anticipated close for this transaction is in line with AES' intent to exit the majority of its coal assets by the end of 2025.

(2) In November 2021, Alto Maipo SpA filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code. After Chapter 11 filing, the Company no longer has control over Alto Maipo and therefore deconsolidated the business. In May 2022, Alto Maipo emerged from bankruptcy. The restructured business is considered a VIE and the Company continues to account for the business as a deconsolidated entity.

(3) On December 1, 2022, Southland Energy sold an additional 14.9% ownership interest in the Southland Energy assets. Following the sale, AES holds 50.1% of Southland Energy's interest and this business continues to be consolidated by AES.

(4) TermoAndes is located in Argentina, but is connected to both the SING in Chile and the SADI in Argentina.

(5) AES operates this facility through management or O&M agreements and to date owns no equity interest in the business.

(6) Entered into an agreement to sell 26% interest in these businesses in November 2020.

(7) Plant also includes an adjacent regasification facility, as well as an 80 TBTU LNG storage tank, or an operating capacity of 180,000 m^3.

(8) Plant also includes an adjacent regasification facility, as well as two LNG storage tanks: Andres with 70 TBTU, or an operating capacity of 160,000 m^3 and Enadom with 50 TBTU, or an operating capacity of 120,000 m^3.

(9) Includes: Alfalfal, Queltehues and Volcan.

(10) On June 29, 2023, Warrior Run terminated its PPA with Potomac Edison. As part of the agreement, Warrior Run stopped selling its electricity to Potomac Edison, but will continue to provide capacity to Potomac Edison through May 31, 2024. The previous expiration for the PPA was 2030.

Under construction — The majority of projects under construction have executed mid- to long-term PPAs. The following table lists our plants under construction in the Energy Infrastructure SBU[1]:

Business	Location	Fuel	Gross MW	AES Equity Interest	Expected Date of Commercial Operations
San Matias	Chile	Wind	65	99 %	1H 2024
Andes Solar 4	Chile	Solar	225	99 %	2H 2024
		Energy Storage	135		
Gatun	Panama	Gas	670	24 %	2H 2024
Andes Solar 2a	Chile	Energy Storage	80	51 %	1H 2025
			1,175		

AES Chile

Business Description — In Chile, through AES Andes, we are engaged in the generation and supply of electricity (energy and capacity) in the SEN—see *International Energy Markets and Regulatory Environment* below. AES Andes is a publicly traded company in Chile and has applied to be de-listed. AES Andes owns all of our assets in Chile. AES has a 99.5% ownership interest in AES Andes, the third largest generation operator in Chile in terms of installed capacity with 3,516 MW, excluding energy storage, and has a market share of approximately 11% as of December 31, 2023. In addition, AES Andes has 237 MW of energy storage systems in operation.

AES Andes owns a diversified generation portfolio in Chile in terms of geography, technology, customers, and energy resources. AES Andes' generation plants are located near the principal electricity consumption centers, including Santiago, Valparaiso, and Antofagasta. AES Andes' diverse generation portfolio provides flexibility for the management of contractual obligations with regulated and unregulated customers, provides backup energy to the spot market and facilitates operations under a variety of market and hydrological conditions.

AES Andes' Green Blend strategy aims to reduce carbon intensity and incorporate renewable energy to extend our existing conventional PPAs. This strategy de-links company's PPAs from legacy fossil resources, grows its renewable energy portfolio, and delivers a competitive, reliable energy solution. In line with the Green Blend strategy, AES Andes has committed to not build additional coal-based power plants and to advance the development of new renewables projects, including the implementation of BESS and other technological innovations that will provide greater flexibility and reliability to the system.

AES Andes currently has long-term contracts with an average remaining term of approximately 12 years with unregulated customers, such as mining and industrial companies, mainly with pricing indexed to CPI. AES Andes also has contracts with regulated companies with a maximum remaining term of one year, which include pass-through mechanisms for fuel costs along with pricing indexed to CPI.

In addition to energy payments, AES Andes also receives capacity payments to compensate for availability during periods of peak demand. The grid operator, Coordinador Electrico Nacional ("CEN"), annually determines the capacity requirements for each power plant. The capacity price is fixed semiannually by the National Energy Commission and indexed to CPI and other relevant indices.

Key Financial Drivers — Hedging strategies at AES Andes limit volatility to the underlying financial drivers. In addition, financial results are likely to be driven by many factors, including, but not limited to:

- spot market prices (largely impacted by dry hydrology scenarios, forced outages and international fuel prices);
- changes in current regulatory rulings altering the ability to pass through or recover certain costs;
- fluctuations of the Chilean peso;
- tax policy changes; and
- legislation promoting renewable energy and/or more restrictive regulations on thermal generation assets.

Decarbonization Strategy — The Chilean government's decarbonization plan includes the complete retirement of the SEN coal fleet by the end of 2040 and carbon neutrality by 2050. Following the issuance of Supreme Decree Number 42 on December 26, 2020 by the Ministry of Energy and per the disconnection and termination agreement signed with the Chilean government in June 2019, AES Andes accelerated the retirement plans of its Ventanas 1 and Ventanas 2 coal-fired units, disconnecting them from the SEN as of June 30, 2022 and December 31, 2023, respectively.

In July 2021, AES Andes committed to allow the shutdown of coal-fired operations at its Ventanas 3, Ventanas 4, Angamos 1, and Angamos 2 units as early as January 1, 2025, once the safety, sufficiency, and competitiveness of the system allows it. These four units together have an installed capacity of 1,097 MW and each unit has publicly announced phase-out plans in line with the Company's decarbonization strategy. In July 2021, the Company also sold its entire ownership interest in Guacolda, a 764 MW coal-fired plant located in Chile.

On February 8, 2024, AES Andes was authorized by the CEN to definitively disconnect the coal-fired generation units Norgener 1 and Norgener 2, with an installed capacity of 276 MW, from the SEN on March 31, 2024.

Ventanas, Angamos, Guacolda, and Norgener represent an aggregate of 2.5 GW of coal-fired capacity, or 82% of AES Andes' legacy coal fleet. AES Andes continues to work under the Green Blend strategy to accelerate the phase-out of the remaining coal-fired units.

Development Strategy — AES Andes is committed to reducing the carbon intensity of the Chilean power grid and plans to increase the renewable energy capacity in its portfolio. As part of this commitment, AES Andes is building wind, solar, and battery projects to supply agreements with its main mining customers.

In total, the pipeline in Chile currently includes 5.4 GW under development at different stages and geographical locations. Within this portfolio, the Company has made significant progress in the development of non-conventional renewable energy ("NCRE") projects that are already contracted. The Rinconada wind project (258 MW) is being developed in the Biobío region. Several projects are being developed in the Antofagasta region: a new expansion of the Andes Solar power plant which will include a battery system to optimize solar generation (186 MW + 266 MW-3hr), the Cristales solar power plant (187 MW + 267 MW-3hr), the Bolero battery system (136 MW-3hr), and the Pampas hybrid project (120 MW wind, 160 MW solar + 229 MW-3hr).

In addition, Empresa Eléctrica Angamos, a subsidiary of AES Andes, received environmental approval for an innovative initiative on November 29,2023 to revolutionize the conversion of thermoelectric plants using molten salts. This project explores the possibility of replacing the current coal-fired generation of units 1 and 2 of the Angamos thermoelectric power plant, located in Mejillones, Antofagasta region, with a molten salt system. With this technology, renewable energy is stored as heat to later be used to provide energy and emission-free capacity to the electrical system.

Empresa Eléctrica Angamos is also promoting the advancement of green hydrogen technology for mass production through the Adelaida project, which contemplates the installation of a small-scale green hydrogen production plant with a capacity of 1,000 kg/day of green hydrogen, equivalent to 2.5 MW of power.

U.S. Conventional Generation

Business Description — In the U.S., we own a conventional generation portfolio. The principal markets and locations where we are engaged in the generation and supply of electricity (energy and capacity) are the California Independent System Operator ("CAISO"), PJM, and Puerto Rico. AES Southland, operating in the CAISO, is our most significant generation business. In June 2023, the Company closed on an agreement to terminate the PPA for the Warrior Run coal-fired power plant and to continue providing capacity through May 2024.

Many of our non-renewable U.S. generation plants provide baseload operations and are required to maintain a guaranteed level of availability. Any change in availability has a direct impact on financial performance. Some plants are eligible for availability bonuses if they meet certain requirements. Coal and natural gas are used as the primary fuels. Coal prices are set by market factors internationally, while natural gas prices are generally set domestically. Price variations for these fuels can change the composition of generation costs and energy prices in our generation businesses.

Before the termination of its PPA in June 2023, Warrior Run operated as a QF, as defined under the PURPA, under a long-term contract with an electric utility that had a mandatory obligation to purchase power from QFs at the utility's avoided cost (i.e. the likely costs for both energy and capital investment that would have been incurred by the purchasing utility if that utility had to provide its own generating capacity or purchase it from another source). Warrior Run no longer operates as a QF.

Our non-QF generation businesses in the U.S. currently operate as Exempt Wholesale Generators as defined under the Energy Policy Act of 1992, amending the Public Utility Holding Company Act (“PUHCA”). These businesses, subject to approval of FERC, have the right to sell power at market-based rates, either directly to the wholesale market or to a third-party offtaker such as a power marketer or utility/industrial customer. Under the Energy Policy Act and FERC's regulations, approval from FERC to sell wholesale power at market-based rates is generally dependent upon a showing to FERC that the seller lacks market power in generation and transmission, that the seller and its affiliates cannot erect other barriers to market entry, and that there is no opportunity for abusive transactions involving regulated affiliates of the seller.

The U.S. wholesale electricity market consists of multiple distinct regional markets that are subject to both federal regulation, as implemented by FERC, and regional regulation as defined by rules designed and implemented by the RTOs, non-profit corporations that operate the regional transmission grid and maintain organized markets for electricity. These rules, for the most part, govern such items as the determination of the market mechanism for setting the system marginal price for energy and the establishment of guidelines and incentives for the addition of new capacity. See Item 1A.—*Risk Factors* for additional discussion on U.S. regulatory matters.

AES Southland

Business Description — AES Southland is one of the largest generation operators in California by aggregate installed capacity, with an installed gross capacity of 3,699 MW at the end of 2023. The five coastal power plants comprising AES Southland are in areas that are critical for local reliability and play an important role in integrating the increasing amounts of renewable generation resources in California. The AES Southland Energy Infrastructure assets are composed of three once-through cooling ("OTC") power plants and two combined cycle gas-fired generation facilities.

Southland — Southland comprises AES Huntington Beach, LLC, AES Alamitos, LLC, and AES Redondo Beach ("Southland OTC units"). Until December 31, 2023, the Southland OTC units were contracted through Resource Adequacy Purchase Agreements (“RAPAs”). Under the RAPAs, as approved by the California Public Utilities Commission, these generating stations provided resource adequacy capacity, and had no obligation to produce or sell any energy to the RAPA counterparty. However, the generating stations were required to bid energy into the California ISO markets. Southland OTC units entered into commodity swap contracts to economically hedge price variability inherent in electricity sales arrangements. Compensation under these RAPAs was dependent on the availability of the Southland OTC units in the California ISO market. Failure to achieve the minimum availability target would result in an assessed penalty.

Commencing on January 1, 2024, AES Huntington Beach, LLC and AES Alamitos, LLC, are contracted through Standby Capacity Purchase Agreements with the California Department of Water Resources (“California DWR”), an agency of the State of California, as part of the Electricity Supply Strategic Reliability Reserve Program (‘Strategic Reserve”) established under California Assembly Bill 205. Under these agreements, California DWR is purchasing each facility’s available capacity for a three-year term.

The Southland OTC units are subject to a variety of rules governing water use and discharge. The units are required to comply with the more stringent of state or federal requirements. AES Southland's current plan is to comply with the SWRCB OTC Policy by shutting down and permanently retiring all remaining generating units that utilize OTC by the compliance dates included in the OTC Policy. See *United States Environmental and Land-Use Legislation and Regulations—Cooling Water Intake* for further discussion of AES Southland’s plans regarding the OTC Policy.

Southland Energy — AES Huntington Beach Energy, LLC and AES Alamitos Energy, LLC, (collectively "Southland Energy") each operate under 20-year tolling agreements with Southern California Edison ("SCE") to provide 1,387 MW of combined cycle gas-fired generation (through 2040),

The contracts are RAPAs with annual energy tolling put options. If Southland Energy exercises the annual put option, all capacity, energy and ancillary services will be sold to SCE in exchange for a monthly energy and fixed capacity payment that covers fixed operating cost, debt service, and return on capital. In addition, SCE will reimburse variable costs and provide the natural gas. Southland Energy may exercise the annual put option for any contract year by delivering notice of such exercise to SCE at least one year before the start of such contract year, and no more than two years before the start of any contract year. If the annual put options are not exercised, Southland Energy is required to sell the physical output of the combined cycle gas-fired generation units to AES Integrated Energy. AES Integrated Energy is required to bid energy into the California ISO market. AES Integrated Energy enters into commodity swap contracts to economically hedge price variability inherent in electricity sales arrangements. Southland Energy continues to receive the monthly fixed capacity payments for periods when the put option is not exercised.

Key Financial Drivers — AES Southland's availability is one of the most important drivers of operations, along with market demand and prices for gas and electricity.

AES Puerto Rico

Business Description — AES Puerto Rico owns and operates a 524 MW coal-fired cogeneration plant representing approximately 10% of the installed capacity in Puerto Rico. This plant is fully contracted through a long-term PPA with PREPA expiring in 2027. AES Puerto Rico receives a capacity payment based on the plants' twelve month rolling average availability, receiving the full payment when the availability is 90% or higher. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Macroeconomic and Political—Puerto Rico* for further discussion of the long-term PPAs with PREPA.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to, improved operational performance and plant availability.

AES Argentina and TermoAndes

Business Description — AES operates plants in Argentina within the Energy Infrastructure SBU totaling 2,814 MW, representing 6% of the country's total installed capacity. AES owns a diversified generation portfolio in Argentina in terms of geography, technology, and fuel source, and AES Argentina's plants are placed in strategic locations within the country in order to provide energy to the spot market and contracted customers.

AES primarily sells its energy in the wholesale electricity market where prices are largely regulated. In 2023, approximately 79% of the energy was sold in the wholesale electricity market and 21% was sold under contract by TermoAndes power plant.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- forced outages;
- exposure to fluctuations of the Argentine peso;
- timely collection of FONINVEMEM installments and outstanding receivables (see *International Energy Markets and Regulatory Environment* below);
- natural gas prices and availability for contracted generation at TermoAndes; and
- domestic energy demand and exports.

AES Vietnam

Business Description — Mong Duong 2 is a 1,242 MW gross coal-fired plant located in the Quang Ninh Province of Vietnam and was constructed under a BOT service concession agreement expiring in 2040. This is the first coal-fired BOT plant using pulverized coal-fired boiler technology in Vietnam. The BOT company has a PPA with EVN and a Coal Supply Agreement with Vinacomin, both expiring in 2040.

On November 29, 2023, AES executed an agreement to sell its entire 51% interest in the Mong Duong 2 plant. The sale is expected to close by the end of 2025, subject to customary approvals, including from the Government of Vietnam and the minority partners in Mong Duong 2.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to, the operating performance and availability of the facility.

Development Strategy — In Vietnam, we continue to advance the development of our Son My LNG terminal project, which has a design capacity of up to 9.6 million metric tonnes per annum, and the Son My 2 CCGT project, which has a capacity of about 2,250 MW.

In September 2019 we received a formal approval as the government-mandated investor with 100% equity ownership in the Son My 2 CCGT project and executed a statutory memorandum of understanding with Vietnam's Ministry of Industry and Trade to continue developing the Son My 2 CCGT project under Vietnam's Build-Operate-Transfer legal framework. In October 2019, we received formal approval as a government-mandated investor in the Son My LNG terminal project in partnership with PetroVietnam Gas. In September 2021, we signed the joint venture agreement with PetroVietnam Gas and established Son My LNG Terminal LLC in April 2022. In July 2023, Son My LNG Terminal LLC received approval of investment policy and as the government-approved investor from the Binh Thuan Provincial People's Committee. The Son My 2 CCGT project will utilize the Son My LNG terminal project and will be its anchor customer.

AES Mexico

Business Description — The TEG and TEP pet coke-fired plants, located in Tamuin, San Luis Potosi, supply power to their offtakers under long-term PPAs expiring in 2027 with a 90% availability guarantee. TEG and TEP secure their fuel under a long-term contract. TEG and TEP are in the migration process from the Legacy market to the New Electric Industry law. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Macroeconomic and Political—Mexico Migration and Wheeling Tariffs* for further discussion of the migration process.

Merida is a CCGT located on Mexico's Yucatan Peninsula. Merida sells power to the CFE under a capacity and energy based long-term PPA through 2025. Additionally, the plant purchases natural gas and diesel fuel under a long-term contract with one of the CFE's subsidiaries, the cost of which is then passed through to the CFE under the terms of the PPA.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- contracting levels, providing additional benefits from improved operational performance, including performance incentives and/or excess energy sales;
- changes in the methodology to calculate spot energy prices or Locational Marginal Prices, which impacts the excess energy sales to the CFE (see *International Energy Markets and Regulatory Environment* below) in TEG and TEP under self-supply scheme; and
- improved operational performance and plant availability.

AES Dominicana

Business Description — AES Dominicana has two operating subsidiaries within the Energy Infrastructure SBU, Andres and Los Mina, both of which are owned 65% by AES. With a total of 697 MW of installed capacity, AES provides 12% of the country's capacity and supplies approximately 16% of the country's energy demand via these generation facilities. 668 MW was predominantly contracted until 2022 with government-owned distribution companies and large customers, and have been contracted back with the distribution companies in January 2023.

Andres owns and operates a combined cycle natural gas turbine and an energy storage facility with combined generation capacity of 329 MW, as well as the only LNG import terminal in the country, with 160,000 cubic meters of storage capacity. Los Mina owns and operates a combined cycle facility with two natural gas turbines and an energy storage facility with combined generation capacity of 368 MW.

AES has a strategic partnership with the Estrella and Linda Groups ("Estrella-Linda"), two leading Dominican industrial groups that manage a diversified business portfolio. In December 2023, AES completed the sale of an additional 10% ownership interest in AES Dominicana to the existing partners and a 10% interest to Grupo Popular's subsidiary, AFI Popular, selling 20% ownership interest in total. After this transaction, AES' ownership interest in AES Dominicana is 65%.

AES Dominicana has entered into a new long-term LNG purchase contract through the second half of 2034 to cover the expected dispatch for Andres and Los Mina. Andres has long-term contracts to sell regasified LNG to industrial users and third party power plants within the Dominican Republic, thereby capturing demand from industrial and commercial customers and for other power generation companies that had switched their operations to natural gas.

AES partnered with Energas in a joint venture to operate the 50 km Eastern Pipeline from February 2020. The joint venture also developed an expanded LNG facility of 120,000 cubic meters, including additional storage, regasification, and truck loading capacity, which reached COD in the fourth quarter of 2023.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- changes in spot prices due to fluctuations in commodity prices (since fuel is a pass-through cost under the PPAs, any variation in oil prices will impact spot sales for Andres and Los Mina);
- expiring PPAs, lower contracting levels and the extent of capacity awarded; and
- growth in domestic natural gas demand, supported by new infrastructure such as the Eastern Pipeline and second LNG tank.

Development Strategy — AES will continue to develop the commercialization of natural gas and incorporate partners directly in gas infrastructure projects.

AES Bulgaria

Business Description — Our AES Maritza plant is a 690 MW lignite fuel thermal power plant. AES Maritza's entire power output is contracted with NEK, the state-owned public electricity supplier, independent energy producer, and trading company. Maritza is contracted under a 15-year PPA that expires in May 2026. AES Maritza is collecting receivables from NEK in a timely manner. However, NEK's liquidity position is subject to political conditions and regulatory changes in Bulgaria.

The DG Comp is reviewing NEK’s PPA with AES Maritza pursuant to the European Union’s state aid rules. AES Maritza believes that its PPA is legal and in compliance with all applicable laws. For additional details see Item 7.—*Management’s Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Regulatory* of this Form 10-K.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- regulatory changes in the Bulgarian power market;
- results of the DG Comp review;
- availability and load factor of the operating units; and
- NEK's ability to meet the payment terms of the PPA contract with Maritza.

AES Panama

Business Description — AES owns and operates a natural gas-fired power plant with 381 MW of generation capacity. Furthermore, AES operates an LNG regasification facility, a 180,000 cubic meter storage tank, and a truck loading facility. In December 2023, AES completed the sale of 35% ownership interest in Colon to Grupo Linda and Grupo Estrella, our current minority partners in AES Dominicana. After this transaction, AES' ownership interest is 65% in both assets.

Our thermal asset in Panama has PPAs with distribution companies for a total contracted capacity of 350 MW expiring in August 2028, which matches the term of the LNG supply agreement of such thermal assets. The LNG supply contract has enough flexibility to divert volumes to the Dominican Republic, which increases the connectivity of our two onshore terminals and allows to optimize the LNG position of the portfolio. Colon LNG Marketing continues developing the LNG market in Latin America, with clients already established in Panama and Colombia. Additional efforts are being undertaken in Costa Rica, other Central America regions, and Caribbean islands, mainly focusing on small scale LNG logistics.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- changes in hydrology, which impacts the spot prices and exposes the business to variability in the cost of replacement power;
- fluctuations in commodity prices, mainly fuel oil and natural gas, which affect the cost of thermal generation and spot prices;
- constraints imposed by the capacity of transmission lines connecting the west side of the country with the load, keeping surplus power trapped during the rainy season; and
- country demand as GDP growth is expected to remain strong over the short and medium term.

Development Strategy — Given our LNG facility's excess capacity in Panama, the company is developing natural gas supply solutions for third parties such as power generators and industrial and commercial customers. This strategy will support a growing demand for natural gas in the region and will contribute to AES' mission by reducing CO_2 emissions as a result of using LNG.

AES Jordan

Business Description — In Jordan, AES has a 37% controlling interest in Amman East, a 472 MW oil/gas-fired plant fully contracted with the national utility under a 25-year PPA expiring in 2033, and a 36% controlling interest in the IPP4 plant, a 250 MW oil/gas-fired peaker plant fully contracted with the national utility until 2039. We consolidate the results in our operations as we have a controlling interest in these businesses.

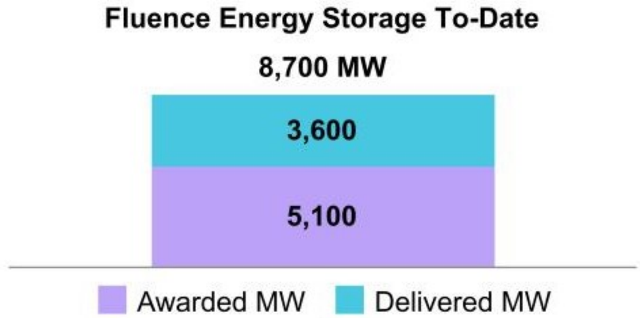
On November 10, 2020, AES executed a sale and purchase agreement to sell approximately 26% effective ownership interest in both the Amman East and IPP4 plants. The sale is expected to close in the first half of 2024 subject to customary closing conditions, including lender consents and regulatory approvals.

New Energy Technologies

Investing in innovative technologies

Key investments:

FLUENCE
A Siemens and AES Company
uplight
5B



Key events in 2023

- Fluence hit milestone of 20 GWh deployed and contracted globally
- Achieved first monetization of the innovation portfolio, netting $156 million in proceeds from 4% Fluence equity stake sale in December 2023

Strategic outlook

- Fluence total contracted backlog of 14.3 GW (5.1 GW in energy storage, 3.5 GW in service contracts, and 5.7 GW in digital contracts)
- Uplight positioned for expansion in partners & programs, along with an enhanced ability to create/ manage energy grids after AutoGrid acquisition

New Energy Technologies

Our New Energy Technologies SBU includes investments in new and innovative technologies, designed to both strengthen the competitive advantage of AES' core businesses and enable the growth of new green businesses. This segment includes ownership stakes in third-party platforms, as well as new initiatives developed internally. It includes investments in Fluence, Uplight, and 5B, as well as our green hydrogen initiatives. We are a leader in developing green hydrogen and we are pursuing multiple projects across our geographies with total potential installed electrolyzer capacity of up to 1,200 metric tons/day by 2030.

Fluence and Uplight are unconsolidated entities and their results are reported in *Net equity in losses of affiliates* on our Consolidated Statements of Operations. 5B is accounted for using the measurement alternative and AES will record income or loss only when it receives dividends from 5B or when there is a change in the observable price or an impairment of the investment.

Fluence

Business Description — Fluence, created in 2018 as a joint venture by AES and Siemens AG, is a global energy storage technology and services company aligned with the AES strategy to drive decarbonization of the electric sector. Fluence is a leading global provider of energy storage products and services and artificial intelligence (AI)-enabled digital applications for renewables and storage.

On November 1, 2021, Fluence Energy, Inc. completed its IPO, generating primary proceeds of approximately $936 million, after expenses, and is listed on Nasdaq under the symbol "FLNC". AES owns Class B-1 common stock, entitling AES to five votes per share held, and continues to hold its economic interest in the operating subsidiary of Fluence Energy, Inc. AES' economic interest in Fluence is currently 29%. The Company continues to account for Fluence as an equity method investment.

Key Financial Drivers — Fluence's financial results are driven by the growth in its product revenue, an efficient cost structure that is expected to benefit from increased scale, and profit margins on customer contracts. Fluence's pipeline of potential projects is global.

Development Strategy — The grid-connected energy storage sector is expanding rapidly. By incorporating energy storage across the electric power network, utilities and communities around the world will optimize their infrastructure investments, increase network flexibility and resiliency, and accelerate cost-effective integration of renewable electricity generation. According to the 2H 2023 Energy Storage Market Outlook published by BloombergNEF in October 2023, the global energy storage market is growing at a 27% compound annual growth rate to 2030, with annual additions reaching 110 GW/372 GWh, or 2.6x expected 2023 gigawatt installations. Additional growth opportunities exist in the provision of operational and maintenance services associated with energy storage products, as well as the provision of digital applications and solutions to improve performance and economic output. Fluence is positioned to be a leading participant in this growth, with 3.6 GW of energy storage assets deployed and 5.1 GW of contracted backlog, with a gross global pipeline of 13.2 GW as of December 31, 2023.

Uplight

Business Description — The Company holds an equity interest in Uplight as part of its digitization and growth strategy. Uplight offers a comprehensive digital platform for utility customer engagement. Uplight provides software and services to approximately 70 of the leading electric and gas utilities, principally in the U.S., with the mission of motivating and enabling energy users and providers to transition to a clean energy ecosystem. Uplight's solutions form a unified, end-to-end customer energy experience system that delivers innovative energy efficiency, demand response, and clean energy solutions quickly. Utility and energy company leaders rely on Uplight and its customer-focused digital energy experiences to improve customer satisfaction, reduce service costs, increase revenue, and reduce carbon emissions.

At December 31, 2023 the Company held a 29.4% ownership interest in Uplight. On February 9, 2024, another shareholder was issued additional shares in Uplight as a result of contributing a business and $40 million in cash to Uplight. The business contributed is AutoGrid, a market leader in the fast-growing Virtual Power Plant ("VPP") space. As a result of the additional shares issued to the other shareholder, AES' interest was diluted to approximately 25%. Uplight continues to be accounted for as an equity method investment.

Key Financial Drivers — Uplight's financial results are driven by the rate of growth of new customers and the extension of additional services to existing customers. Revenue growth primarily drives its financial results, given the relative significance of fixed operating costs.

Development Strategy — AES' collaboration with Uplight is designed to create value for Uplight, AES, and their respective customers. AES Indiana and AES Ohio have implemented Uplight's consumer engagement solutions in support of energy efficiency and demand response programs, as well as piloted new solutions with Uplight.

5B

Business Description — The Company has a strategic investment in 5B, a solar technology innovator with the mission to accelerate the transformation of the world to a clean energy future. 5B's technology design enables solar projects to be installed up to three times faster, while allowing for up to two times more energy within the same footprint and can sustain higher wind speeds than traditional solar plants.

Key Financial Drivers — 5B is accounted for under the measurement alternative and AES will record income or loss only when it receives dividends from 5B or when there is a change in the observable price or an impairment of the investment.

Development Strategy — In addition to a large global market for third party projects, we believe there is an addressable market of nearly 5 GW across our development pipeline. As of December 31, 2023, 5B has achieved sales orders of over 250 MW. AES expects to utilize this technology in conjunction with ongoing automation and digital initiatives to speed up delivery time and lower costs. 5B technology has been deployed at multiple locations in AES for a total of 23 MW across five projects in Panama, Chile, El Salvador, and the U.S., with future deployments expected across markets in the AES portfolio.

International Energy Markets and Regulatory Environment

Chile

The Chilean electricity industry is divided into three business segments: generation, transmission, and distribution. Private companies operate in all three segments, and generators can enter into PPAs to sell energy to regulated and unregulated customers, as well as to other generators in the spot market.

Chile operates in a single power market, referred to as the SEN, which is managed by the grid operator CEN. The SEN has an installed capacity of 31,466 MW, and represents 99% of the installed generation capacity of the country.

CEN coordinates all generation and transmission companies in the SEN. CEN minimizes the operating costs of the electricity system, while maximizing service quality and reliability requirements. CEN dispatches plants in merit order based on their variable cost of production, allowing for electricity to be supplied at the lowest available cost. In the south-central region of the SEN, thermoelectric generation is required to fulfill demand not satisfied by hydroelectric, solar, and wind output and is critical to provide reliable and dependable electricity supply under dry hydrological conditions in the highest demand area of the SEN. In the northern region of the SEN, which includes the Atacama Desert, thermoelectric capacity represents the majority of installed capacity. The fuels used for thermoelectric generation, mainly coal, diesel, and LNG, are indexed to international prices. In 2023, the installed generation capacity in the Chilean market was composed of 42% thermoelectric, 23% hydroelectric, 21% solar, 13% wind, and 1% other fuel sources.

Hydroelectric plants represent a significant portion of the system's installed capacity. Precipitation and snow melt impact hydrological conditions in Chile. Rain occurs principally from June to August and snow melt occurs from September to December. These factors affect dispatch of the system's hydroelectric and thermoelectric generation plants, thereby influencing spot market prices.

The Ministry of Energy has primary responsibility for the Chilean electricity system directly or through the National Energy Commission and the Superintendency of Electricity and Fuels.

All generators can sell energy through contracts with regulated distribution companies or directly to unregulated customers. Customers whose connected demand capacity is higher than 5 MW are excluded from the regulated market and are referred to as unregulated customers. Customers with connected capacity between 0.5 MW and 5 MW can opt for regulated or unregulated contracts for a minimum period of four years. By law, both regulated and unregulated customers are required to purchase all electricity under contracts. Generators may also sell energy to other power generation companies on a short-term basis at negotiated prices outside the spot market. Electricity prices in Chile are denominated in USD, although payments are made in Chilean pesos.

Dominican Republic

The Dominican Republic energy market is a decentralized industry consisting of generation, transmission, and distribution businesses. Generation companies can earn revenue through short- and long-term PPAs, ancillary services, and a competitive wholesale generation market. All generation, transmission, and distribution companies are subject to and regulated by the General Electricity Law.

Two main agencies are responsible for monitoring compliance with the General Electricity Law:

- The National Energy Commission drafts and coordinates the legal framework and regulatory legislation. They propose and adopt policies and procedures to implement best practices, support the proper functioning and development of the energy sector, and promote investment.
- The Superintendence of Electricity's main responsibilities include monitoring compliance with legal provisions, rules, and technical procedures governing generation, transmission, distribution, and commercialization of electricity. They monitor behavior in the electricity market in order to prevent monopolistic practices.

In addition to the two agencies responsible for monitoring compliance with the General Electricity Law, the Ministry of Industry and Commerce supervises commercial and industrial activities in the Dominican Republic as well as the fuels and natural gas commercialization to end users.

The Dominican Republic has one main interconnected system with 5,640 MW of installed capacity, composed of thermal (70%), hydroelectric (11%), wind (7%), and solar (12%).

El Salvador

El Salvador's national electric market is composed of generation, distribution, transmission, and marketing businesses, a market and system operator, and regulatory agencies. The operation of the transmission system and the wholesale market is based on production costs with a marginal economic model that rewards efficiency and allows investors to have guaranteed profits, while end users receive affordable rates. The energy sector is governed by the General Electricity Law, which establishes two regulatory entities responsible for monitoring its compliance:

- The National Energy and Hydrocarbons Direction is the highest authority on energy policy and strategy, and the coordinating body for the different energy sectors. One of its main objectives is to promote investment in non-conventional renewable sources to diversify the energy matrix.
- The General Superintendence of Electricity and Telecommunications regulates the market and sets consumer prices, and, jointly with the distribution companies in El Salvador, developed the tariff calculation applicable from 2023 until 2027.

AES El Salvador distribution rates are regulated by SIGET and are established through a traditional cost-based rate-setting process. AES El Salvador is permitted to recover its costs of providing distribution service as well as earn a regulated rate of return on assets, determined by the regulator, based on the utility's allowed regulated asset base, capital structure, and cost of capital. El Salvador has a national electric grid that interconnects directly with Guatemala and Honduras, allowing transactions with all Central American countries. The sector has approximately 2,459 MW of installed capacity, composed of thermal (55%), hydroelectric (22%), solar (9%), biomass (12%), and wind (2%) generation plants.

Bulgaria

The electricity sector in Bulgaria is regulated by the Bulgarian Energy Act, which has been amended in November 2023 in order to fulfill a commitment by Bulgaria to the European Commission to fully liberalize its electricity market by the end of 2025. The Bulgarian electricity market allows both regulated and competitive segments until the end of 2025. From 2026 onwards, the regulated segment is expected to cease to exist. NEK will retain its capacity as the public provider of electricity until the end of June 2024, under which NEK acts as a single buyer and seller for all regulated transactions on the market. From July 2024 onwards, Bulgarian distribution companies serving the regulated market will source their electricity needs exclusively from the competitive segment of the market. Electricity outside the regulated market trades on one of the platforms of the Independent Bulgarian Electricity Exchange day-ahead market, intra-day market, or bilateral contracts market.

Bulgaria’s power sector is supported by a diverse generation mix, universal access to the grid, and numerous cross-border connections with neighboring countries. In addition, it plays an important role in the energy balance in the southeast European region.

Bulgaria has 13 GW of installed capacity enabling the country to meet and exceed domestic demand and export energy. Installed capacity is primarily thermal (45%), hydro (25%), and nuclear (16%).

Panama

The Panamanian power sector is composed of three distinct operating business units: generation, distribution, and transmission. Generators can enter into short-term and long-term PPAs with distributors or unregulated consumers. In addition, generators can enter into backup supply contracts with each other. Outside of PPAs, generators may buy and sell energy in the short-term market. Generators can only contract up to their firm capacity.

Three main agencies are responsible for monitoring compliance with the General Electricity Law:

- The National Secretary of Energy in Panama ("SNE") has the responsibilities of planning, supervising, and controlling policies of the energy sector within Panama. The SNE proposes laws and regulations to the executive agencies that regulate the procurement of energy and hydrocarbons for the country.
- The National Authority of Public Services ("ASEP") is an autonomous agency of the government. ASEP is responsible for the regulations, control and oversight of public services in Panama, including electricity, the transmission and distribution of natural gas utilities, and the companies that provide such services.
- The National Dispatch Center ("CND") is in charge of the operation of the system and the management of the electricity market. They are responsible for implementing the economic dispatch of electricity in the wholesale market. The National Dispatch Center's objectives are to minimize the total cost of generation and maintain the reliability and security of the electric power system. Short-term power prices are determined on an hourly basis by the last dispatched generating unit. Physical generation of energy is determined as a result of the optimization of the economic dispatch regardless of contractual arrangements.

Panama's current total installed capacity is 4,134 MW, composed of hydroelectric (45%), thermal (32%), solar (15%), and wind (8%) generation.

Mexico

Mexico's main electrical system is called the National Interconnected System ("SIN"), which geographically covers an area from Puerto Peñasco, Sonora to Cozumel, Quintana Roo. Mexico also has three isolated electrical systems: (1) the Baja California Interconnected System, which is interconnected with the western interconnection; (2) the Baja California Sur Interconnected System; and (3) the Mulegé Interconnected System, a very small electrical system. All three are isolated from the SIN and from each other. The Mexican power industry comprises the activities of generation, transmission, distribution, and commercialization segments, considering transmission and distribution to be exclusive state services.

In addition to the Ministry of Energy, three main agencies are responsible for regulating the market agents and their activities, monitoring compliance with the laws and regulations, and the surveillance of operational compliance and management of the wholesale electricity market:

- The Energy Regulatory Commission is responsible for the establishment of directives, orders, methodologies, and standards to regulate the electric and fuel markets, as well as granting permits.
- The National Center for Energy Control, as an ISO, is responsible for managing the wholesale electricity market, transmission and distribution infrastructure, planning network developments, guaranteeing open access to network infrastructure, executing competitive mechanisms to cover regulated demand, and setting transmission charges.
- The Electricity Federal Commission ("CFE") owns the transmission and distribution grids and is also the country's basic supplier. CFE is the offtaker for IPP generators, and together with its own power units has more than 50% of the current generation market share.

Mexico has an installed capacity totaling 87 GW with a generation mix composed of thermal (65%), hydroelectric (14%), wind (8%), solar (8%), and other fuel sources (5%).

Brazil

In Brazil, electricity production is predominantly renewable, with emphasis on hydroelectric plants, although there has been a significant advancement in intermittent renewable sources. The National Interconnected System (SIN) consists of four subsystems: South, Southeast/Midwest, Northeast and North regions. The interconnection of the systems through the transmission grid provides for the transfer of energy between subsystems, gaining synergies from the diversity of hydrological regimes of the basins, and allowing the market to be served safely and economically.

In Brazil, the Ministry of Mines and Energy determines the maximum amount of energy a generation plant can sell, called physical guarantee, representing the long-term average expected energy production of the plant. Under current rules, physical guarantee energy can be sold to distribution companies through long-term regulated auctions or under unregulated bilateral contracts with large consumers or energy trading companies.

Brazil has installed capacity of 201 GW, composed of hydroelectric (55%), thermoelectric (23%), renewable (21%), other sources (1%). Operation is centralized and controlled by the national operator, ONS, and regulated by the Brazilian National Electric Energy Agency ("ANEEL"). The ONS dispatches generators based on their marginal cost of production and on the risk of system rationing. Key variables for the dispatch decision are forecasted hydrological conditions, reservoir levels, electricity demand, fuel prices, and thermal generation availability.

In case of unfavorable hydrology, the ONS will reduce hydroelectric dispatch to preserve reservoir levels and increase dispatch of thermal plants to meet demand. The consequences of unfavorable hydrology are (i) higher energy spot prices due to higher energy production costs at thermal plants and (ii) the need for hydro plants to purchase energy in the spot market to fulfill their contractual obligations.

A mechanism known as the MRE (Energy Reallocation Mechanism) was created under ONS to share hydrological risk across MRE hydro generators by using a generation scaling factor ("GSF") to adjust generators' physical guarantee during periods of hydrological scarcity. If the hydro plants generate less than the total MRE physical guarantee, the hydro generators may need to purchase energy in the short-term market. When total hydro generation is higher than the total MRE physical guarantee, the surplus is proportionally shared among its participants and they may sell the excess energy on the spot market.

Brazil Indirect Tax Reform — On December 20, 2023, Constitutional Amendment 132 was enacted and overhauls the federal, state, and local indirect taxes on consumption and transactions in Brazil. This amendment is the fundamental pillar of the broad Tax Reform which also requires a Complementary Law to the Constitution (LC), to be proposed in 2024.

Based on the amendment, the new tax model will eliminate all indirect taxes and create a dual VAT (federal and state/municipal), plus a federal excise tax (no impact is expected in AES Brasil businesses). The combined rate of the dual VAT is expected to be between 25% and 27% and aligns VAT input credits to amounts charged by suppliers and the tax-on-tax cascading effect for the collection at the location of the final consumer. Additionally, the indirect taxes incentive regime for infrastructure development ("REIDI") will be extinguished in 2027, but a new form of exemption for capital goods will be addressed in a Complementary Law.

The transition period to the new tax model will last 7 years (starting in 2026 and ending in 2032), during which two tax systems will coexist, with old and new taxes collected in parallel. Furthermore, the proposal requires the Executive Branch to send to the National Congress the Income Tax Reform bill of law within 90 days after the constitutional amendment takes effect. If this second phase of the tax reform is approved in 2024, it will take effect in 2025.

Argentina

Argentina has one main power system, the SADI, which serves 91% of the country. As of December 31, 2023, the installed capacity of the SADI totaled 43,774 MW. The SADI's installed capacity is composed primarily of thermoelectric generation (59%) and hydroelectric generation (26%), as well as wind (8%), nuclear (4%), and solar (3%).

Thermoelectric generation in the SADI is fueled primarily by natural gas. However, scarcity of natural gas during winter periods (June to August) due to transport constraints results in the use of alternative fuels, such as oil and coal. The SADI is also highly reliant on hydroelectric plants. Hydrological conditions impact reservoir water levels and largely influence the dispatch of the system's hydroelectric and thermoelectric generation plants and, therefore, influence market costs. Precipitation in Argentina occurs principally from May to October.

The Argentine regulatory framework divides the electricity sector into generation, transmission, and distribution. The wholesale electric market is comprised of generation companies, transmission companies, distribution companies, and large customers who are permitted to trade electricity. Generation companies can sell their output in the spot market or under PPAs. CAMMESA manages the electricity market and is responsible for dispatch coordination. The Electricity National Regulatory Agency is in charge of regulating public service activities and the Secretariat of Energy regulates system framework and grants concessions or authorizations for sector activities. In Argentina, there is a tolling scheme in which the regulator establishes prices for electricity and defines fuel reference prices. For the energy sold in the spot market, generators are compensated for fixed costs and non-fuel variable costs, under prices mainly denominated in Argentine pesos and CAMMESA is in charge of providing the natural gas and liquid fuels required by the generation companies, except for coal. For the energy sold under PPAs (as Energía PLUS from TermoAndes) the generators buy their required fuel at a reference price established by the regulator. As a result, our businesses are particularly sensitive to changes in regulation.

The expansion of renewable capacity in the system is promoted by allowing the new power plants to sign contracts either with CAMMESA through the RenovAr program or directly by trading energy in the private market.

During 2023, although the government increased prices to the end user, subsidies and the system deficit also increased. By December 2023, distribution companies recovered an average 47% of the total cost of the system.

In past years, AES Argentina contributed certain accounts receivable to fund the construction of three power plants under FONINVEMEM agreements. These receivables accrue interest and are collected in monthly installments over 10 years after commercial operation date of the related plant takes place. In 2020, FONINVEMEM I and II installments were fully repaid and in 2021 the ownership interests in Termoeléctrica San Martín and Termoeléctrica Manuel Belgrano were defined after the incorporation of the National Government as majority shareholder. The transfer of the power plants to these companies has not yet occurred. FONINVEMEM III is related to Termoeléctrica Guillermo Brown, which began operations in April 2016, and the installments are still being collected. AES Argentina will receive a pro rata ownership interest in this plant, which shall not be greater than 30%, once the accounts receivables have been fully repaid. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Long-Term Receivables* and Note 7.—*Financing Receivables* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further discussion of receivables in Argentina.

In 2022 and 2023, the Argentine peso devalued against the USD by approximately 42% and 78%, respectively, and Argentina's economy continued to be highly inflationary. Since September 2019, currency controls have been established to govern the devaluation of the Argentine peso and keep Argentine central bank reserves at acceptable levels.

Colombia

Electricity supply in Colombia is concentrated in one main system, the SIN, which encompasses one-third of Colombia's territory, providing electricity to 97% of the country's population. The SIN's installed capacity, primarily hydroelectric (66%), thermal (30%) and other renewables (4%), totaled 19,942 MW as of December 31, 2023. The marked seasonal variations in Colombia's hydrology result in price volatility in the short-term market. In 2023, 74% of total energy demand was supplied by hydroelectric plants.

The electricity sector in Colombia operates under a competitive market framework for the generation and sale of electricity, and a regulated framework for transmission and distribution of electricity. The distinct activities of the electricity sector are governed by Colombian laws and CREG, the Colombian regulating entity for energy and gas. Other government entities have a role in the electricity industry, including the Ministry of Mines and Energy, which defines the government's policy for the energy sector; the Public Utility Superintendency of Colombia, which is in charge of overseeing utility companies; and the Mining and Energy Planning Unit, which is in charge of expansion planning of the generation and transmission network.

The generation sector is organized on a competitive basis with companies selling their generation in the wholesale market at the short-term price or under bilateral contracts with other participants, including distribution companies, generators and traders, and unregulated customers at freely negotiated prices. The National Dispatch Center dispatches generators in merit order based on bid offers in order to ensure that demand will be satisfied by the lowest cost combination of available generating units.

The expansion of the system is supported by two schemes: i) reliability charge auctions where firm energy commitments are focused on conventional technology power plants, and ii) auctions of long-term energy contracts assigned for periods of 15 years aimed at non-conventional renewable resources.

Vietnam

The Ministry of Industry and Trade in Vietnam is primarily responsible for formulating a program to restructure the power industry, developing the electricity market, and promulgating electricity market regulations. The fuel supply is owned by the government through Vinacomin, a state-owned entity, and PetroVietnam.

The Vietnam power market is divided into three regions (North, Central, and South), with total installed capacity of approximately 80 GW. The fuel mix in Vietnam is composed primarily of coal (33%), hydropower (28%) and renewables, including solar, wind, and biomass (27%). EVN, the national utility, owns 37% of installed generation capacity.

The government is in the process of realigning EVN-owned companies into three different independent operations in order to create a competitive power market. The first stage of this realignment was the implementation of the Competitive Electricity Market, which has been in operation since 2012. The second stage was the introduction of the Electricity Wholesale Market, which has been in operation since the beginning of 2019. The third and final stage impacts the Electricity Retail Market. The reforms are currently in development. BOT power plants will not directly participate in the power market; alternatively, a single buyer will bid the tariff on the power pool on their behalf.

Puerto Rico

Puerto Rico has a single electric grid managed by PREPA, a state-owned entity that provides virtually all of the electric power consumed in Puerto Rico and generates, transmits, and distributes electricity to 1.5 million customers. Since June 2021, PREPA has contracted LUMA Energy to manage the transmission, distribution and commercialization activities. The Puerto Rico Energy Bureau is the main regulatory body. The bureau approves wholesale and retail rates, sets efficiency and interconnection standards, and oversees PREPA's compliance with Puerto Rico's renewable portfolio standard.

Puerto Rico's electricity is 93% produced by thermal plants (51% from petroleum, 33% from natural gas, and 9% from coal), while the remaining 7% is supplied by renewable resources (wind and solar).

Jordan

The Jordan electricity transmission market is a single-buyer model with the state-owned National Electric Power Company ("NEPCO") responsible for transmission. NEPCO generally enters into long-term PPAs with IPPs to fulfill energy procurement requests from distribution utilities.

Environmental and Land-Use Regulations

The Company faces certain risks and uncertainties related to numerous environmental laws and regulations, including existing and potential GHG legislation or regulations, and actual or potential laws and regulations pertaining to water discharges, waste management (including disposal of coal combustion residuals), and certain air emissions, such as SO_2, NO_X, particulate matter, mercury, and other hazardous air pollutants. Such risks and uncertainties could result in increased capital expenditures or other compliance costs which could have a material adverse effect on certain of our U.S. or international subsidiaries, and our consolidated results of operations. For further information about these risks, see Item 1A.—*Risk Factors—Our operations are subject to significant government regulation and could be adversely affected by changes in the law or regulatory schemes; Several of our businesses are subject to potentially significant remediation expenses, enforcement initiatives, private party lawsuits and reputational risk associated with CCR; Our businesses are subject to stringent environmental laws, rules and regulations;* and *Concerns about GHG emissions and the potential risks associated with climate change have led to increased regulation and other actions that could impact our businesses* in this Form 10-K. For a discussion of the laws and regulations of individual countries within each SBU where our subsidiaries operate, see discussion within Item 1.—*Business* of this Form 10-K under the applicable SBUs.

Many of the countries in which the Company does business have laws and regulations relating to the siting, construction, permitting, ownership, operation, modification, repair and decommissioning of, and power sales from electric power generation or distribution assets. In addition, international projects funded by the International Finance Corporation, the private sector lending arm of the World Bank, or many other international lenders are subject to World Bank environmental standards or similar standards, which tend to be more stringent than local country standards. The Company often has used advanced generation technologies in order to minimize environmental impacts, such as combined fluidized bed boilers and advanced gas turbines, and environmental control devices such as flue gas desulphurization for SO_2 emissions and selective catalytic reduction for NO_x emissions.

Environmental laws and regulations affecting electric power generation and distribution facilities are complex, change frequently, and have become more stringent over time. The Company has incurred and will continue to incur capital costs and other expenditures to comply with these environmental laws and regulations. The Company may be required to make significant capital or other expenditures to comply with these regulations. There can be no assurance that the businesses operated by the subsidiaries of the Company will be able to recover any of these compliance costs from their counterparties or customers such that the Company's consolidated results of operations, financial condition, and cash flows would not be materially affected.

Various licenses, permits, and approvals are required for our operations. Failure to comply with permits or approvals, or with environmental laws, can result in fines, penalties, capital expenditures, interruptions, or changes to our operations. Certain subsidiaries of the Company are subject to litigation or regulatory action relating to environmental permits or approvals. See Item 3.—*Legal Proceedings* in this Form 10-K for more detail with respect to environmental litigation and regulatory action.

United States Environmental and Land-Use Legislation and Regulations

In the United States, the CAA and various state laws and regulations regulate emissions of SO_2, NO_X, particulate matter, GHGs, mercury, and other hazardous air pollutants. Certain applicable rules are discussed in further detail below.

CSAPR — CSAPR addresses the "good neighbor" provision of the CAA, which prohibits sources within each state from emitting any air pollutant in an amount which will contribute significantly to any other state's nonattainment of, or interference with maintenance of, any NAAQS. The CSAPR required significant reductions in SO_2 and NO_X emissions from power plants in many states in which subsidiaries of the Company operate. The Company is currently required to comply with the CSAPR in certain states, including in Indiana and Maryland. The CSAPR is implemented in part through a market-based program under which compliance may be achievable through the acquisition and use of emissions allowances created by the EPA. The Company complies with CSAPR through operation of existing controls and purchases of allowances on the open market, as needed.

In October 2016, the EPA published a final rule to update the CSAPR to address the 2008 ozone NAAQS ("CSAPR Update Rule"). Following legal challenges related to the CSAPR Update Rule, on April 30, 2021, the EPA issued the Revised CSAPR Update Rule. The Revised CSAPR Update Rule required affected electric generating units ("EGUs") within certain states (including Indiana and Maryland) to participate in a new trading program, the

CSAPR NO_x Ozone Season Group 3 trading program. These affected EGUs received fewer NO_x Ozone Season allowances beginning in 2021.

On June 5, 2023, the EPA published a final Federal Implementation Plan ("FIP") to address air quality impacts with respect to the 2015 Ozone NAAQS. The rule establishes a revised CSAPR NO_x Ozone Season Group 3 trading program for 22 states, including Indiana and Maryland and became effective during 2023. The FIP also includes enhancements to the revised Group 3 trading program, which include a dynamic budget setting process beginning in 2026, annual recalibration of the allowance bank to reflect changes to affected sources, a daily backstop emissions rate limit for certain coal-fired electric generating units beginning in 2024, and a secondary emissions limit prohibiting certain emissions associated with state assurance levels. It is too early to determine the impact of this final rule, but it may result in the need to purchase additional allowances or make operational adjustments.

While the Company's additional CSAPR compliance costs to date have been immaterial, the future availability of and cost to purchase allowances to meet the emission reduction requirements is uncertain at this time, but it could be material.

New Source Review ("NSR") — The NSR requirements under the CAA impose certain requirements on major emission sources, such as electric generating stations, if changes are made to the sources that result in a significant increase in air emissions. Certain projects, including power plant modifications, are excluded from these NSR requirements if they meet the routine maintenance, repair, and replacement ("RMRR") exclusion of the CAA. There is ongoing uncertainty and significant litigation regarding which projects fall within the RMRR exclusion. Over the past several years, the EPA has filed suits against coal-fired power plant owners and issued NOVs to a number of power plant owners alleging NSR violations. See Item 3.—*Legal Proceedings* in this Form 10-K for more detail with respect to environmental litigation and regulatory action, including an NOV issued by the EPA against AES Indiana concerning NSR and prevention of significant deterioration issues under the CAA. If NSR requirements are imposed on any of the power plants owned by the Company's subsidiaries, the results could have a material adverse impact on the Company's business, financial condition, and results of operations.

Regional Haze Rule — The EPA's "Regional Haze Rule" established timelines for states to improve visibility in national parks and wilderness areas throughout the United States by establishing reasonable progress goals toward meeting a national goal of natural visibility conditions in Class I areas by the year 2064 through a series of state implementation plans (SIPs), which may result in additional emissions control requirements for electric generating units. SIPs for the first planning period (through 2018) did not result in material impact to AES facilities. For all future SIP planning periods, states must evaluate whether additional emissions reduction measures may be needed to continue making reasonable progress toward natural visibility conditions. The deadline for submittal of the SIP covering the second planning period was July 31, 2021. To date, none of the states in which we operate have submitted plans identifying potential impacts to Company facilities. However, we cannot predict the possible outcome or potential impacts of this matter at this time.

NAAQS — Under the CAA, the EPA sets NAAQS for six principal pollutants considered harmful to public health and the environment, including ozone, particulate matter, NO_X, and SO_2, which result from fossil-fuel combustion. Areas meeting the NAAQS are designated "attainment areas" while those that do not meet the NAAQS are considered "nonattainment areas." Each state must develop a plan to bring nonattainment areas into compliance with the NAAQS, which may include imposing operating limits on individual plants. The EPA is required to review NAAQS at five-year intervals.

Based on the current and potential future ambient air standards, certain of the states in which the Company's subsidiaries operate have determined or will be required to determine whether certain areas within such states meet the NAAQS. Some of these states may be required to modify their SIPs to detail how the states will attain or maintain their attainment status. As part of this process, it is possible that the applicable state environmental regulatory agency or the EPA may require reductions of emissions from our generating stations to reach attainment status for ozone, fine particulate matter, NO_X, or SO_2. The compliance costs of the Company's U.S. subsidiaries could be material.

Mercury and Air Toxics Standard — In April 2012, the EPA’s rule to establish maximum achievable control technology standards for hazardous air pollutants regulated under the CAA emitted from coal and oil-fired electric utilities, known as “MATS”, became effective and AES facilities implemented measures to comply, as applicable.

In June 2015, the U.S. Supreme Court remanded MATS to the D.C. Circuit due to the EPA’s failure to consider costs before deciding to regulate power plants under Section 112 of the CAA and subsequently remanded MATS to the EPA without vacatur. On March 6, 2023, the EPA published a final rule reaffirming its 2016 finding that it is appropriate and necessary to regulate emissions under MATS. On April 24, 2023, the EPA published the proposed MATS Residual Risk and Technology Review rule which would lower certain emissions limits and revise certain other aspects of MATS. It is too early to determine the potential impacts of this proposal rule.

Further rulemakings and/or proceedings are possible; however, in the meantime, MATS remains in effect. We currently cannot predict the outcome of the regulatory or judicial process, or its impact, if any, on our MATS compliance planning or ultimate costs.

Greenhouse Gas Emissions — In January 2011, the EPA began regulating GHG emissions from certain stationary sources, including a pre-construction permitting program for certain new construction or major modifications, known as the Prevention of Significant Deterioration ("PSD"). If future modifications to our U.S.-based businesses' sources become subject to PSD for other pollutants, it may trigger GHG BACT requirements and the cost of compliance with such requirements may be material.

On October 23, 2015, the EPA's rule establishing NSPS for new electric generating units ("EGUs") became effective, establishing CO_2 emissions standards for newly constructed coal-fueled electric generating plants, which reflects the partial capture and storage of CO_2 emissions from the plants. The EPA also promulgated NSPS applicable to modified and reconstructed electric generating units, which will serve as a floor for future BACT determinations for such units. The NSPS could have an impact on the Company's plans to construct and/or modify or reconstruct electric generating units in some locations. On December 20, 2018, the EPA published proposed revisions to the final NSPS for new, modified, and reconstructed coal-fired electric utility steam generating units proposing that the best system of emissions reduction for these units is highly efficient generation that would be equivalent to supercritical steam conditions for larger units and sub-critical steam conditions for smaller units, and not partial carbon capture and sequestration, as was finalized in the 2015 final NSPS. The EPA did not include revisions for natural-gas combined cycle or simple cycle units in the December 20, 2018 proposal. Legal challenges to the GHG NSPS are being held in abeyance at this time. On May 23, 2023, the EPA published a proposed rule that would establish CO_2 emissions limits for certain new fossil-fuel fired stationary combustion turbines that commence construction or are modified after May 23, 2023.

On July 8, 2019, the EPA published the final Affordable Clean Energy ("ACE") Rule which would have established CO_2 emission rules for existing power plants under CAA Section 111(d) and would have replaced the EPA's 2015 Clean Power Plan Rule ("CPP"). However, on January 19, 2021, the D.C. Circuit vacated and remanded the ACE Rule. Subsequently, on June 30, 2022, the Supreme Court reversed the judgment of the D.C. Circuit Court and remanded for further proceedings consistent with its opinion, holding that the “generation shifting” approach in the CPP exceeded the authority granted to the EPA by Congress under Section 111(d) of the CAA. As a result of the June 30, 2022 Supreme Court decision, on October 27, 2022, the D.C. Circuit issued a partial mandate, holding pending challenges to the ACE Rule in abeyance. On May 23, 2023, the EPA published a proposed rule that would vacate the ACE Rule, establish emissions guidelines in the form of CO_2 emissions limitations for certain existing EGUs and would require states to develop State Plans that establish standards of performance for such EGUs that are at least as stringent as the EPA’s emissions guidelines. Depending on various EGU-specific factors, the bases of proposed emissions guidelines range from routine methods of operation to carbon capture and sequestration or co-firing low-GHG hydrogen starting in the 2030s. It is too early to determine the potential impact of the proposed rule and the results of further proceedings and potential future greenhouse gas emissions regulations remain uncertain, but could be material.

On January 20, 2021, President Biden signed and submitted an instrument for the U.S. to rejoin the Paris Agreement effective February 19, 2021. In addition, in November 2023, the international community gathered at the 28th Conference to the Parties on the UN Framework Convention on Climate Change ("COP28"). The Parties agreed to non-binding language calling on countries to transition away from fossil fuels in energy systems to achieve net zero emissions by 2050.

As such, there is some uncertainty with respect to the impact of GHG rules. The GHG BACT requirements will not apply at least until we construct a new major source or make a major modification of an existing major source, and the NSPS for new EGUs will not require us to comply with an emissions standard until we construct a new electric generating unit. We do not have any planned major modifications of an existing source or plans to construct a new major source at this time which are expected to be subject to these regulations. Furthermore, the EPA, states, and other utilities are still evaluating potential impacts of the GHG regulations in our industry. In light of these uncertainties, we cannot predict the impact of the EPA’s current and future GHG regulations on our consolidated results of operations, cash flows, and financial condition.

Due to the future uncertainty of these regulations and associated litigation, we cannot at this time determine the impact on our operations or consolidated financial results, but we believe the cost to comply with a new Section 111(d) Rule, should it be implemented in a prior or a substantially similar form, could be material. The GHG NSPS for new EGUs remains in effect at this time, and, absent further action from the EPA that rescinds or substantively revises the NSPS, it could impact any Company plans to construct and/or modify or reconstruct electric generating units in some locations, which may have a material impact on our business, financial condition, or results of operations.

Cooling Water Intake — The Company's facilities are subject to a variety of rules governing water use and discharge. In particular, the Company's U.S. facilities are subject to the CWA Section 316(b) rule issued by the EPA effective in 2014 that seeks to protect fish and other aquatic organisms drawn into cooling water systems at power plants and other facilities. These standards require affected facilities to choose among seven best technology available ("BTA") options to reduce fish impingement. In addition, certain facilities must conduct studies to assist permitting authorities to determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms. It is possible that this process, which includes permitting and public input, could result in the need to install closed-cycle cooling systems (closed-cycle cooling towers), or other technology. Finally, the standards require that new units added to an existing facility to increase generation capacity are required to reduce both impingement and entrainment. It is not yet possible to predict the total impacts of this final rule at this time, including any challenges to such final rule and the outcome of any such challenges. However, if additional capital expenditures are necessary, they could be material.

Power plants are required to comply with the more stringent of state or federal requirements. At present, the California state requirements are more stringent and have earlier compliance dates than the federal EPA requirements, and are therefore applicable to the Company's California assets. Certain OTC units were required to be retired in 2019 to provide interconnection capacity and/or emissions credits prior to startup of the new generating units at AES Alamitos and AES Huntington Beach. AES Southland's current plan is to comply with the SWRCB OTC Policy by shutting down and permanently retiring all remaining generating units that utilize OTC by the compliance dates included in the OTC Policy. Following earlier extensions, in 2021, the AES Redondo Beach compliance date was extended to December 31, 2023 and there is currently no plan to replace the OTC generating units at AES Redondo Beach following their retirement effective January 1, 2024. Following earlier extensions, on August 15, 2023, the State Water Board considered the SACCWIS recommendation and adopted an amendment to the OTC Policy that established a final compliance date of December 31, 2026 for AES Alamitos and AES Huntington Beach. These extensions are contingent upon the facilities participating in the Strategic Reserve established by California Assembly Bill, AB 205, which addresses grid reliability risks from extreme events.

Water Discharges — In June 2015, the EPA and the U.S. Army Corps of Engineers ("the Agencies") published a rule defining federal jurisdiction over waters of the U.S., known as the "Waters of the U.S." (“WOTUS”) rule. WOTUS defines the geographic reach and authority of the Agencies to regulate streams, wetlands, and other water bodies under the CWA. There have been multiple Supreme Court decisions and dueling regulatory definitions over the past several years concerning the appropriate standard for how to properly determine whether a wetland or stream that is not navigable is considered a WOTUS. On May 25, 2023, the U.S. Supreme Court rendered a decision (“Decision”) in the case of *Sackett v. Environmental Protection Agency*, addressing the definition of WOTUS with regards to the CWA. This decision provides a standard that substantially restricts the Agencies' ability to regulate certain types of wetlands and streams. Specifically, under this decision, wetlands that do not have a continuous surface connection with traditional interstate navigable water are not federally jurisdictional.

On September 8, 2023, the Agencies published final rule amendments in the Federal Register to amend the final “Revised Definition of ‘Waters of the United States’” rule. This final rule amendment conforms the definition to the definition adopted in the Decision. The Agencies have amended key aspects of the regulatory text to conform the rule to the Decision. It is too early to determine whether the outcome of litigation or current or future revisions to rules interpreting federal jurisdiction over WOTUS may have a material impact on our business, financial condition, or results of operations.

In November 2015, the EPA published its final ELG rule to reduce toxic pollutants discharged into waters of the U.S. by steam-electric power plants through technology applications. These effluent limitations for existing and new sources include dry handling of fly ash, closed-loop or dry handling of bottom ash, and more stringent effluent limitations for flue gas desulfurization wastewater. Operational practices and/or wastewater treatment technologies already installed and operated at U.S. businesses met the requirements of these rules. Following the 2019 U.S. Court of Appeals vacatur and remand of portions of the 2015 ELG rule related to leachate and legacy water, on

March 29, 2023, the EPA published a proposed rule revising the 2020 Reconsideration Rule. The proposed rule would establish new best available technology economically achievable effluent limits for flue gas desulfurization wastewater, bottom ash treatment water, and combustion residual leachate. It is too early to determine whether any outcome of litigation or current or future revisions to the ELG rule might have a material impact on our business, financial condition, and results of operations.

On April 23, 2020, the U.S. Supreme Court issued a decision in the *Hawaii Wildlife Fund v. County of Maui* case related to whether a CWA permit is required when pollutants originate from a point source but are conveyed to navigable waters through a nonpoint source, such as groundwater. The Court held that discharges to groundwater require a permit if the addition of the pollutants through groundwater is the functional equivalent of a direct discharge from the point source into navigable waters. A number of legal cases relevant to determination of "functional equivalent" are ongoing in various jurisdictions. On November 27, 2023, the EPA issued a draft guidance addressing how the Supreme Court decision would be applied to the NPDES permit program as it relates to functional equivalent discharge. It is too early to determine whether the Supreme Court decision or the result of litigation to "functional equivalent" may have a material impact on our business, financial condition, or results of operations.

Waste Management — On October 19, 2015, an EPA rule regulating CCR under the Resource Conservation and Recovery Act as nonhazardous solid waste became effective. The rule established nationally applicable minimum criteria for the disposal of CCR in new and currently operating CCR landfills and CCR surface impoundments, including location restrictions, design and operating criteria, groundwater monitoring, corrective action and closure requirements, and post-closure care. On December 16, 2016, the Water Infrastructure Improvements for the Nation Act ("WIN Act") was signed into law. This includes provisions to implement the CCR rule through a state permitting program, or if the state chooses not to participate, a possible federal permit program. On February 20, 2020, the EPA published a proposed rule to establish a federal CCR permit program that would operate in states without approved CCR permit programs. If this rule is finalized before Indiana or Puerto Rico establishes a state-level CCR permit program, AES CCR units in those locations could eventually be required to apply for a federal CCR permit from the EPA. The EPA has indicated that it will implement a phased approach to amending the CCR Rule, which is ongoing. On January 11, 2022, the EPA released the first in a series of proposed and final determinations regarding CCR Part A Rule demonstrations and compliance-related letters notifying certain facilities of their compliance obligations under the federal CCR regulations. The determinations and letters include interpretations regarding implementation of the CCR Rule. On April 8, 2022, petitions for review were filed challenging these EPA actions. The petitions are consolidated in *Electric Energy, Inc. v. EPA.* It is too early to determine the direct or indirect impact of these letters or any determinations that may be made.

On May 18, 2023, the EPA published a proposed rule that would expand the scope of CCR units regulated by the CCR Rule to include inactive surface impoundments at inactive generating facilities as well as additional inactive and closed landfills and certain other accumulations of CCR. It is too early to determine the outcome of this proposed rule and any potential impact.

The CCR rule, current or proposed amendments to the federal CCR rule or state/territory CCR regulations, the results of groundwater monitoring data, or the outcome of CCR-related litigation could have a material impact on our business, financial condition, and results of operations. AES Indiana would seek recovery of any resulting expenditures; however, there is no guarantee we would be successful in this regard.

International Environmental Regulations

Chile

Chilean law requires all electricity generators to supply a certain portion of their total contractual obligations with NCRE. Generation companies are able to meet this requirement by building NCRE generation capacity (wind, solar, biomass, geothermal, and small hydroelectric technology) or purchasing NCREs from qualified generators. Non-compliance with the NCRE requirements will result in fines. AES Andes currently fulfills the NCRE requirements by utilizing AES Andes' solar, wind, and biomass power plants.

Since 2017, emissions of particulate matter, SO_2, NO_X, and CO_2 are monitored for plants with an installed capacity over 50 MW; these emissions are taxed. In the case of CO_2, the tax is equivalent to $5 per ton emitted. Certain PPAs have clauses allowing the Company to pass the green tax costs to unregulated customers, while some distribution PPAs do not allow for the pass through of these costs. During 2021, the Chilean General Water Direction, as part of the Ministry of Public Works, established the obligation to install and maintain effective monitoring systems for water withdrawal. The Company is currently implementing these systems in the power plants for which they are required.

During 2022, new regulations associated with enviromental monitoring requirements were published, including Law 21,455, which is the framework on climate change; the Ventanas power plant new Operational Plan; emission standards for back up generators; and recently enacted Law 21,505, which promotes electric energy storage and electromobility.

During 2023, increasingly demanding environmental regulations have been issued, which will require adjustments in controls throughout the life cycle of any investment project, that is, in the development, construction and operation phase. Environmental prevention and management models must be adjusted to prevent behaviors that could be considered environmental crimes, as well as investments performed to comply with new regulatory standards.

In this context, the following regulations were enacted:

- Law No 21.595: Economic and Environmental Crimes Law, which includes the regulation of crimes of attacks against the environment, establishing effective prison sentences in addition to the financial responsibility of companies.
- Law No. 21,600 creates the Biodiversity and Protected Areas Service; and
- Decree No. 1/2022 Establishes the Emission Standard for Artificial Lighting generated by outdoor lighting, which changes the level of applicability of its requirements, expanding its scope of application at the national level and contemplating some stricter limits for protected areas.

In the coming months the following regulations are expected to be published:

- New emission standards for thermoelectric power plants (standard under review since 2020);
- New noise emission standard for fixed sources (under review since 2019); and
- A modification to the System Regulations.

AES Andes and its subsidiaries are undergoing administrative environmental sanctions processes. The compliance program associated with the Ventanas power plant is being executed. The Angamos power plant is currently undergoing an environmental review process of its Environmental permit (RCA in Chile). See Item 3.—*Legal Proceedings* in this Form 10-K for further discussion.

Bulgaria

In July 2020, the EU approved the Next Generation EU ("NGEU") recovery instrument, which aims at mitigating the economic and social impact of the COVID-19 pandemic and making European economies and societies more sustainable. The main funding component of NGEU is the EU's Recovery and Resilience Facility ("RRF"). In November 2023, the European Commission approved an amended version of Bulgaria's Recovery and Resilience Plan ("RRP") that describes the reforms and investments which Bulgaria wishes to make with the support of the RRF. In its RRP, Bulgaria commits to designing a coal phase-out plan aiming at retiring coal-fired power plants by 2038.

The plan includes a 40% reduction in carbon emissions by the end of 2025 and a ceiling on carbon emissions from 2026 onwards. The mechanism to achieve the target is undefined and the potential impact to Maritza's revenues is expected to be limited.

Brazil

In Brazil, the National Environmental Council ("CONAMA") is responsible for environmental licensing procedures. Inspections are performed by authorities at federal, state and municipal levels. The programs developed by AES Brasil are designed to restore and preserve biodiversity and are in compliance with local procedures and the obligations assumed in AES Brasil's concession with the state government. AES Brasil's main environmental projects include a flora management program which guarantees the production of 1 million seedlings of native tree species, a reservoir repopulation program that aims to maintain the ichthyofauna biodiversity and guarantee continuity of fishing activity by riverside communities, a land fauna monitoring and conservation program, and a water quality monitoring program designed to further understand the structure and functioning of aquatic ecosystems.

In addition, the monitoring and control of reservoir edges is carried out through continuous inspections by the technical team of the Center of Monitoring of Reservoirs ("CMR") through a system of detection of changes, satellite images, aerophotogrammetric surveys, and field inspections.

Argentina

Argentina has agreed to commitments made by the international community ratified in the Paris Agreement and in Law 27,270 passed in September 2016.

In October 2015, Law 27,191 was passed, seeking to create a successful framework for the development of renewable energy. This law set an objective of 8% renewable energy by 2017 and 20% by 2025 and also introduced tax exemptions for importing equipment used in the construction of renewable energy projects in addition to other tax benefits. This framework fostered AES Argentina's construction of Vientos Bonaerenses and Vientos Neuquinos power plants, which are fully contracted with public and private customers in the long term.

In December 2019, Law 27,520 established a minimum budget to grant adequate actions, instruments, and strategies to mitigate and adapt to global climate change effects in all national territories and created the National Office of Climate Change to designate private and public actors to design policies aiming to reduce greenhouse gases and to provide coordinated responses in sectors that are vulnerable to climate change impacts.

All AES Argentina plants are certified under international standards of Quality (ISO 9001), Safety and Health (ISO 45.001) and Environment (ISO 14001).

Colombia

Decree 1076 of 2015 established the current Environmental Licensing Scheme that defines the scope of the National Environmental Licensing Authority ("ANLA") for granting environmental licenses. In recent years, the Ministry of the Environment has generated regulations in connection with licenses, such as the biotic compensation methodology and guidance for presentation of environmental studies in 2018, and the regulation of minor changes to environmental licenses in 2022.

In 2023, the ANLA begun the review of the reference terms for environmental impact studies and is working on a reform to the procedure for licensing process for non-conventional renewable energy projects. The following is highlighted in the regulatory proposal, which is expected to be processed during the first half of 2024:

- All renewable energy projects would be licensed by ANLA.
- The implementation of a new instrument called the Environmental Baseline, which would be used for decision-making regarding the development of Renewable Energy Projects.
- Photovoltaic electricity generation projects that are developed on land classified as suburban, according to municipal planning plans, would not request an environmental license.

At the end of 2023, AES Colombia obtained the environmental license, issued by the ANLA, for the 500 kV line to connect the Guajira pipeline projects. Currently, AES Colombia has obtained environmental licenses for 406 MW of wind projects in Guajira.

Customers

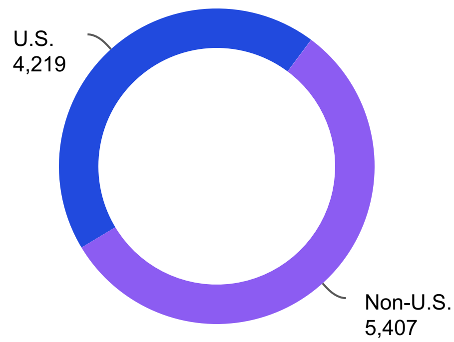
We sell to a wide variety of customers. No individual customer accounted for 10% or more of our 2023 total revenue. In our generation business, we own and/or operate power plants to generate and sell power to wholesale customers such as utilities and other intermediaries. Our utilities sell to end-user customers in the residential, commercial, industrial, and governmental sectors in a defined service area.

Human Capital Management

At AES, our people are instrumental to helping us meet the world's energy needs. Supporting our people is a foundational value for AES. Our actions are grounded in the shared values that shape AES' culture: Safety First, Highest Standards, and All Together. The AES Corporation is led and managed by our Chief Executive Officer and the Executive Leadership Team with the guidance and oversight of our Board of Directors.

As of December 31, 2023, the Company and its subsidiaries had approximately 9,600 full time/permanent employees.

Full Time/Permanent Employees



As of December 31, 2023, approximately 30% of our U.S. employees were subject to collective bargaining agreements. Collective bargaining agreements between us and these labor unions expire at various dates ranging from 2024 to 2026. In addition, certain employees in non-U.S. locations were subject to collective bargaining agreements, representing approximately 50% of the non-U.S. workforce. Management believes that the Company's employee relations are favorable.

Safety

At AES, safety is one of our core values. Conducting safe operations at our facilities around the world, so that each person can return home safely, is the cornerstone of our daily activities and decisions. Safety efforts are led by our Chief Operating Officer and supported by safety committees that operate at the local site level. Hazards in the workplace are actively identified and management tracks incidents so remedial actions can be taken to improve workplace safety.

AES has established a Safety Management System ("SMS") Global Safety Standard that applies to all AES employees, as well as contractors working in AES facilities and construction projects. The SMS requires continuous safety performance monitoring, risk assessment, and performance of periodic integrated environmental, health, and safety audits. The SMS provides a consistent framework for all AES operational businesses and construction projects to set expectations for risk identification and reduction, measure performance, and drive continuous improvements. The SMS standard is consistent with the OHSAS 18001/ISO 45001 standard, and during 2023 approximately 58% of our locations have elected to formally certify their SMS to the OHSAS 18001/ISO 45001 international standard. AES calculates lost time incident ("LTI") rates for our employees and contractors based on OSHA standards, based on 200,000 labor hours, which equates to 100 workers who work 40 hours per week and 50 weeks per year. In 2023, there was an 82% increase in LTI cases. In 2023, AES' LTI Rate was 0.120 for AES People, 0.118 for operational contractors, and 0.076 for construction contractors. In 2023, the Company had one contractor work-related fatality.

Talent

We believe AES' success depends on its ability to attract, develop, and retain key personnel. The skills, experience, and industry knowledge of key employees significantly benefit our operations and performance. We have a comprehensive approach to managing our talent and developing our leaders in order to ensure our people have the right skills for today and tomorrow, whether that requires us to build new business models or leverage leading technologies.

We emphasize employee development and training. To empower employees, we provide a range of development programs and opportunities, skills, and resources they need to be successful by focusing on experience and exposure, as well as formal programs including our Trainee Program.

At AES, we believe that our individual differences make us stronger. Our Diversity and Inclusion Program is led by our Diversity and Inclusion Officer. Governance and standards are guided by the Chief Human Resources Officer, with input from members of the Executive Leadership Team.

Compensation

AES' executive compensation philosophy emphasizes pay-for-performance. Our incentive plans are designed to reward strong performance, with greater compensation paid when performance exceeds expectations and less compensation paid when performance falls below expectations. We invest significant time and resources to ensure our compensation programs are competitive and reward the performance of our people. Every year, AES people who are not part of a collective bargaining agreement are eligible for an annual merit-based salary increase. In addition, individuals are eligible for a salary increase if they receive a significant promotion. For non-collectively bargained employees at certain levels in the organization, we offer annual incentives (bonus) and long-term compensation to reinforce the alignment between AES' employees and AES.

Executive Officers

The following individuals are our executive officers:

Stephen Coughlin, 52 years old, has served as Executive Vice President and Chief Financial Officer since October 2021. Prior to assuming his current position, he led AES' Corporate Strategy and Financial Planning teams, and served as the Chair of the Company's Investment Committee. Prior to that role, he served as the Chief Executive Officer of Fluence. Mr. Coughlin joined AES in 2007 and spent his early years with the company leading Financial Planning & Analysis for AES's renewables portfolio. Mr. Coughlin is a member of the boards of AES Clean Energy Development Holdings, LLC, AES U.S. Investments, Inc., AES U.S. Generation, LLC, and IPALCO. Mr. Coughlin received a bachelor's degree in commerce and finance from the University of Virginia and a Master of Business Administration degree from the University of California at Berkeley.

Bernerd Da Santos*,* 60 years old, has served as Executive Vice President and President of the Renewables SBU since June 2023. Previously, Mr. Da Santos held several positions at AES, including Chief Operating Officer and Executive Vice President from December 2017 to July 2023, Chief Operating Officer and Senior Vice President from 2014 to 2017, Chief Financial Officer, Global Finance Operations from 2012 to 2014, Chief Financial Officer of Global Utilities from 2011 to 2012, Chief Financial Officer of Latin America and Africa from 2009 to 2011, Chief Financial Officer of Latin America from 2007 to 2009, Managing Director of Finance for Latin America from 2005 to 2007, and VP and Controller of La Electricidad de Caracas ("EDC") (Venezuela). Prior to joining AES in 2000, Mr. Da Santos held a number of financial leadership positions at EDC. Mr. Da Santos is a member of the boards of AES Brasil Energia S.A., AES Mong Duong Power Co. Ltd., IPALCO, and Son My LNG Terminal LLC. Mr. Da Santos holds a bachelor's degree with Cum Laude distinction in Business Administration and Public Administration from Universidad José Maria Vargas, a bachelor's degree with Cum Laude distinction in Business Management and Finance, and an MBA with Cum Laude distinction from Universidad José Maria Vargas.

Ricardo Manuel Falú, 44 years old, has served as Executive Vice President and Chief Operating Officer since February 2024. Prior to assuming his current position, Mr. Falú was Senior Vice President and Chief Operating Officer since July 2023 and Senior Vice President and Chief Strategy and Commercial Officer since August 2022. Since March 2023, Mr. Falú has also served as President of the New Energy Technologies SBU. Mr. Falú joined AES in 2003 and, prior to his current roles, served as President of the Andes region from January 2022 to August 2022 and Chief Executive Officer of AES Andes from April 2018 to August 2022, which includes AES Chile, AES Colombia, and AES Argentina. Before that, Mr. Falú served as the Chief Financial Officer for the Company's businesses in the Andes region from 2014 to April 2018 and as Chief Financial Officer for the Company's businesses in the Mexico, Central American, and Caribbean region from 2012 to 2014. He is a member of the boards of Fluence Energy, Inc., AES Andes, IPALCO, AES Ohio, and AES Colombia. Prior to joining AES, Mr. Falú worked as an external auditor, accounting analyst, and financial consultant in Argentina. He holds a Certified Public Accountant degree from the Universidad Nacional de Salta in Argentina and an Executive MBA, graduating Summa Cum Laude from the IAE Business School. He also holds a diploma from the Wharton Advanced Management Program, a Certificate in Management from Darden, and has completed other executive financial and management studies at Darden, Wharton, and Harvard.

Paul L. Freedman, 53 years old, has served as Executive Vice President, General Counsel, and Corporate Secretary since February 2021. Prior to assuming his current position, Mr. Freedman was Senior Vice President and General Counsel from February 2018, Corporate Secretary from October 2018, Chief of Staff to the Chief Executive Officer from April 2016 to February 2018, Assistant General Counsel from 2014 to 2016, and from 2007 to 2014 he held a variety of other positions in the AES legal group. Mr. Freedman is a member of the Boards of, AES U.S. Investments, Inc., IPALCO, AES Ohio, and AES Southland Energy Holdings, LLC. Additionally, Mr Freedman is a member of the Boards of the Business Council for International Understanding and the Coalition for Integrity. Prior to joining AES, Mr. Freedman was Chief Counsel for credit programs at the U.S. Agency for International

Development and he previously worked as an associate at the law firms of White & Case and Freshfields. Mr. Freedman received a B.A. from Columbia University and a J.D. from the Georgetown University Law Center.

***Andrés R. Gluski**,* 66 years old, has been President, Chief Executive Officer and a member of our Board of Directors since September 2011 and is a member of the Innovation and Technology Committee. Under his leadership, AES has become a world leader in implementing clean technologies, including energy storage and renewable power. Prior to assuming his current position, Mr. Gluski served as Executive Vice President and Chief Operating Officer of the Company from 2007 to 2011. Prior to that role, he served in a number of senior roles at AES, including as Regional President of Latin America and was Senior Vice President for the Caribbean and Central America. He is a member of the Board of Waste Management and serves as Chairman of the Americas Society/Council of the Americas. Mr. Gluski is a magna cum laude graduate of Wake Forest University and holds an M.A. and a Ph.D. in Economics from the University of Virginia.

Tish Mendoza, 48 years old, has served as Executive Vice President and Chief Human Resources Officer since February 2021. Prior to assuming her current position, Ms. Mendoza was Senior Vice President, Global Human Resources and Internal Communications and Chief Human Resources Officer from 2012, Vice President of Human Resources, Global Utilities from 2011 to 2012, Vice President of Global Compensation, Benefits and HRIS, including Executive Compensation, from 2008 to 2011, and acted in the same capacity as the Director of the function from 2006 to 2008. Ms. Mendoza is a member of the boards of IPALCO, Fluence Energy, Inc. and AES Ohio, and sits on AES' compensation and benefits committees. Prior to joining AES, Ms. Mendoza was Vice President of Human Resources for a product company in the Treasury Services division of JP Morgan Chase and Vice President of Human Resources and Compensation and Benefits at Vastera, Inc, a former technology and managed services company. Ms. Mendoza earned certificates in Leadership and Human Resource Management, and a bachelor's degree in Business Administration and Human Resources.

***Juan Ignacio Rubiolo**,* 47 years old, has served as Executive Vice President and President of the Energy Infrastructure SBU since March 2023. Prior to assuming his current position, Mr. Rubiolo served as Executive Vice President and President of International Businesses from January 2022 to March 2023, Senior Vice President and President of the MCAC SBU from March 2018 to January 2022, as the Chief Executive Officer of AES Mexico from 2014 to March 2018, and as a Vice President of the Commercial team of the MCAC SBU from 2013 to 2014. Mr. Rubiolo joined AES in 2001 and has worked in AES businesses in the Philippines, Argentina, Mexico, Panama, and the Dominican Republic. Mr. Rubiolo serves on the boards of AES Andes, AES Brasil Energia, and AES Colombia & Cia S.C.A. E.S.P. Mr. Rubiolo has a Science Degree in Business from the Universidad Austral of Argentina, a Master of Project Management from the Quebec University in Canada and has completed the executive business and leadership program at the University of Virginia.

How to Contact AES and Sources of Other Information

Our principal offices are located at 4300 Wilson Boulevard, Arlington, Virginia 22203. Our telephone number is (703) 522-1315. Our website address is *http://www.aes.com*. Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and any amendments to such reports filed pursuant to Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act") are posted on our website. After the reports are filed with, or furnished to the SEC, they are available from us free of charge. Material contained on our website is not part of and is not incorporated by reference in this Form 10-K. The SEC maintains an internet website that contains the reports, proxy and information statements and other information that we file electronically with the SEC at *www.sec.gov*.

Our CEO and our CFO have provided certifications to the SEC as required by Section 302 of the Sarbanes-Oxley Act of 2002. These certifications are included as exhibits to this Annual Report on Form 10-K.

Our CEO provided a certification pursuant to Section 303A of the New York Stock Exchange Listed Company Manual on April 27, 2023.

Our Code of Business Conduct ("Code of Conduct") and Corporate Governance Guidelines have been adopted by our Board of Directors. The Code of Conduct is intended to govern, as a requirement of employment, the actions of everyone who works at AES, including employees of our subsidiaries and affiliates. Our Ethics and Compliance Department provides training, information, and certification programs for AES employees related to the Code of Conduct. The Ethics and Compliance Department also has programs in place to prevent and detect criminal conduct, promote an organizational culture that encourages ethical behavior and a commitment to compliance with the law, and to monitor and enforce AES policies on corruption, bribery, money laundering and associations with terrorists groups. The Code of Conduct and the Corporate Governance Guidelines are located in their entirety on our website. Any person may obtain a copy of the Code of Conduct or the Corporate Governance Guidelines without charge by making a written request to: Corporate Secretary, The AES Corporation, 4300 Wilson Boulevard, Arlington, VA 22203. If any amendments to, or waivers from, the Code of Conduct or the Corporate Governance Guidelines are made, we will disclose such amendments or waivers on our website.

ITEM 1A. RISK FACTORS

You should consider carefully the following risks, along with the other information contained in or incorporated by reference in this Form 10-K. Additional risks and uncertainties also may adversely affect our business and operations. We routinely encounter and address risks, some of which may cause our future results to be materially different than we presently anticipate. The categories of risk we have identified in Item 1A.—*Risk Factors* include risks associated with our operations, governmental regulation and laws, our indebtedness and financial condition. These risk factors should be read in conjunction with Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations* in this Form 10-K and the Consolidated Financial Statements and related notes included elsewhere in this Form 10-K. If any of the following events actually occur, our business, financial results and financial condition could be materially adversely affected.

Risks Associated with our Operations

The operation of power generation, distribution and transmission facilities involves significant risks.

We are in the business of generating and distributing electricity, which involves certain risks that can adversely affect financial and operating performance, including:

- changes in the availability of our generation facilities or distribution systems due to increases in scheduled and unscheduled plant outages, equipment failure, failure of transmission systems, labor disputes, disruptions in fuel supply, poor hydrologic and wind conditions, inability to comply with regulatory or permit requirements, or catastrophic events such as fires, floods, storms, hurricanes, earthquakes, dam failures, tsunamis, explosions, terrorist acts, vandalism, cyber-attacks or other similar occurrences; and
- changes in our operating cost structure, including, but not limited to, increases in costs relating to gas, coal, oil and other fuel; fuel transportation; purchased electricity; operations, maintenance and repair; environmental compliance, including the cost of purchasing emissions offsets and capital expenditures to install environmental emission equipment; transmission access; and insurance.

Our businesses require reliable transportation sources (including related infrastructure such as roads, ports and rail), power sources and water sources to access and conduct operations. The availability and cost of this infrastructure affects capital and operating costs and levels of production and sales. Limitations or interruptions in this infrastructure or at the facilities of our subsidiaries, including as a result of third parties intentionally or unintentionally disrupting this infrastructure or the facilities of our subsidiaries, could impede their ability to produce electricity.

In addition, a portion of our generation facilities were constructed many years ago and may require significant capital expenditures for maintenance. The equipment at our plants requires periodic upgrading, improvement or repair and replacement equipment or parts may be difficult to obtain in circumstances where we rely on a single supplier or a small number of suppliers. The inability to obtain replacement equipment or parts, due to disruption of the supply chain or other factors, may impact the ability of our plants to perform. Breakdown or failure of one of our operating facilities may prevent the facility from performing under applicable power sales agreements which, in certain situations, could result in termination of a power purchase or other agreement or incurrence of a liability for liquidated damages and/or other penalties.

Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of rotating equipment and delivering electricity to transmission and distribution systems. In addition to natural risks, such as earthquakes, floods, lightning, hurricanes and wind, hazards, such as fire, explosion, collapse and machinery failure, are inherent risks in our operations which may occur as a result of inadequate internal processes, technological flaws, human error or actions of third parties or other external events. The control and management of these risks depend upon adequate development and training of personnel and on operational procedures, preventative maintenance plans, and specific programs supported by quality control systems, which may not prevent the occurrence and impact of these risks.

In addition, our battery storage operations also involve risks associated with lithium-ion batteries. On rare occasions, lithium-ion batteries can rapidly release the energy they contain by venting smoke and flames in a manner that can ignite nearby materials as well as other lithium-ion batteries. While more recent design developments for our storage projects seek to minimize the impact of such events, these events are inherent risks of our battery storage operations.

The hazards described above, along with other safety hazards associated with our operations, can 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. The occurrence of any one of these events may result in our being named as a defendant in lawsuits asserting claims for substantial damages, environmental cleanup costs, personal injury and fines and/or penalties.

Furthermore, we and our affiliates are parties to material litigation and regulatory proceedings. See Item 3.—*Legal Proceedings* below. There can be no assurance that the outcomes of such matters will not have a material adverse effect on our consolidated financial position.

We do a significant amount of business outside the U.S., including in developing countries.

A significant amount of our revenue is generated in developing countries and we intend to expand our business in certain developing countries in which AES or its customers have an existing presence. International operations, particularly in developing countries, entail significant risks and uncertainties, including:

- economic, social and political instability in any particular country or region;
- adverse changes in currency exchange rates;
- government restrictions on converting currencies or repatriating funds;
- unexpected changes in foreign laws and regulations or in trade, monetary, fiscal or environmental policies;
- high inflation and monetary fluctuations;
- restrictions on imports of solar panels, wind turbines, coal, oil, gas or other raw materials;
- threatened or consummated expropriation or nationalization of our assets by foreign governments;
- unexpected delays in permitting and governmental approvals;
- unexpected changes or instability affecting our strategic partners in developing countries;
- failure to comply with the U.S. Foreign Corrupt Practices Act, or other applicable anti-bribery regulations;
- unwillingness of governments, agencies, similar organizations or other counterparties to honor contracts;
- unwillingness of governments, government agencies, courts or similar bodies to enforce contracts that are economically advantageous to AES and less beneficial to government or private party counterparties, against those counterparties;
- inability to obtain access to fair and equitable political, regulatory, administrative and legal systems;
- adverse changes in government tax policy and tax consequences of operating in multiple jurisdictions;
- difficulties in enforcing our contractual rights or enforcing judgments or obtaining a favorable result in local jurisdictions; and
- inability to attract and retain qualified personnel.

Developing projects in less developed economies also entails greater financing risks and such financing may only be available from multilateral or bilateral international financial institutions or agencies that require governmental guarantees for certain project and sovereign-related risks. There can be no assurance that project financing will be available or that, once secured, will provide similar terms or flexibility as would be expected from a commercial lender.

Further, our operations may experience volatility in revenues and operating margin caused by regulatory and economic difficulties, political instability and currency devaluations, which may increase the uncertainty of cash flows from these businesses.

Any of these factors could have a material, adverse effect on our business, results of operations and financial condition.

Our businesses may incur substantial costs and liabilities and be exposed to price volatility as a result of risks associated with the wholesale electricity markets.

Some of our businesses sell or buy electricity in the spot markets when they operate at levels that differ from their power sales agreements or retail load obligations or when they do not have any powers sales agreements. Our businesses may also buy electricity in the wholesale spot markets. As a result, we are exposed to the risks of rising and falling prices in those markets. The open market wholesale prices for electricity can be volatile and generally reflect the variable cost of the source generation which could include renewable sources at near zero pricing or thermal sources subject to fluctuating cost of fuels such as coal, natural gas or oil derivative fuels in addition to other factors described below. Consequently, any changes in the generation supply stack and cost of coal, natural gas, or oil derivative fuels may impact the open market wholesale price of electricity.

Volatility in market prices for fuel and electricity may result from, among other things:

- plant availability in the markets generally;
- availability and effectiveness of transmission facilities owned and operated by third parties;
- competition and new entrants;
- seasonality, hydrology and other weather conditions;
- illiquid markets;
- transmission, transportation constraints, inefficiencies and/or availability;
- renewables source contribution to the supply stack;
- increased adoption of distributed generation;
- energy efficiency and demand side resources;
- available supplies of coal, natural gas, and crude oil and refined products;
- generating unit performance;
- natural disasters, terrorism, wars, embargoes, pandemics and other catastrophic events;
- energy, market and environmental regulation, legislation and policies;
- general economic conditions that impact demand and energy consumption; and
- bidding behavior and market bidding rules.

Wholesale power prices may experience significant volatility in our markets which could impact our operations and opportunities for future growth.

The wholesale prices offered for electricity have been volatile in the markets in which we operate due to a variety of factors, including the increased penetration of renewable generation and energy storage resources, low-priced natural gas, demand side management, new regulations and market rules. The levelized cost of electricity from new solar and wind generation sources has decreased substantially over the past decade as solar panel costs and wind turbine costs have declined, while wind and solar capacity factors have increased. These renewable resources have no fuel costs and very low operational costs, while only operating during certain periods of time (daylight) or weather conditions (higher winds). This, combined with changes in oil, gas, and coal pricing, has led to increasingly volatile electricity markets across our markets. Changing weather conditions can also directly impact electricity supply, demand, and generations sources, leading to price volatility.

This trend of volatility in wholesale prices could continue and could have a material adverse impact on the financial performance of our existing generation assets to the extent they currently sell or buy power into the spot market to serve our contracts or will seek to sell power into the spot market once our contracts expire.

Adverse economic developments in China could have a negative impact on demand for electricity in many of our markets.

The Chinese market has been driving global materials demand and pricing for commodities over the past decade. Many of these commodities are produced in our key electricity markets. After experiencing rapid growth for more than a decade, China's economy has experienced decreasing foreign and domestic demand, weak investment, factory overcapacity and oversupply in the property market, and has experienced a significant slowdown in recent years. U.S. tariffs have also had a negative impact on China's economic growth. Further, China's Zero COVID strategy contributed to a significant decrease in GDP growth in 2022 and its GDP growth in 2023 was below growth rates in the years preceding the pandemic. Continued slowing in China's economic growth, demand for commodities and/or material changes in policy could result in lower economic growth and lower demand for electricity in our key markets, which could have a material adverse effect on our results of operations, financial condition and prospects.

We may not have adequate risk mitigation or insurance coverage for liabilities.

Power generation, distribution and transmission involves hazardous activities. We may become exposed to significant liabilities for which we may not have adequate risk mitigation and/or insurance coverage. Furthermore, through AGIC, AES' captive insurance company, we take certain insurance risk on our businesses. We maintain an amount of insurance protection that we believe is customary, but there can be no assurance it will be sufficient or effective in light of all circumstances, hazards or liabilities to which we may be subject. Our insurance does not cover every potential risk associated with our operations. Adequate coverage at reasonable rates is not always obtainable. In particular, the availability of insurance for coal-fired generation assets has decreased as certain insurers have opted to discontinue or limit offering insurance for such assets. Certain insurers have also withdrawn from insuring hydroelectric assets. We cannot provide assurance that insurance coverage will continue to be available in the amounts or on terms similar to our current policies. In addition, insurance may not fully cover the liability or the consequences of any business interruptions such as natural catastrophes, equipment failure or labor dispute. The occurrence of a significant adverse event not adequately covered by insurance could have a material adverse effect on our business, results or operations, financial condition, and prospects.

We may not be able to enter into long-term contracts that reduce volatility in our results.

Many of our generation plants conduct business under long-term sales and supply contracts, which helps these businesses to manage risks by reducing the volatility associated with power and input costs and providing a stable revenue and cost structure. In these instances, we rely on power sales contracts with one or a limited number of customers for the majority of, and in some cases all of, the relevant plant's output and revenues over the term of the power sales contract. The remaining terms of the power sales contracts of our generation plants range from one to more than 20 years. In many cases, we also limit our exposure to fluctuations in fuel prices by entering into long-term contracts for fuel with a limited number of suppliers. In these instances, the cash flows and results of operations are dependent on the continued ability of customers and suppliers to meet their obligations under the relevant power sales contract or fuel supply contract, respectively. Some of our long-term power sales agreements are at prices above current spot market prices and some of our long-term fuel supply contracts are at prices below current market prices. The loss of significant power sales contracts or fuel supply contracts, or the failure by any of the parties to such contracts that prevents us from fulfilling our obligations thereunder, could adversely impact our strategy by resulting in costs that exceed revenue, which could have a material adverse impact on our business, results of operations and financial condition. In addition, depending on market conditions and regulatory regimes, it may be difficult for us to secure long-term contracts, either where our current contracts are expiring or for new development projects. The inability to enter into long-term contracts could require many of our businesses to purchase inputs at market prices and sell electricity into spot markets, which may not be favorable.

We have sought to reduce counterparty credit risk under our long-term contracts by entering into power sales contracts with utilities or other customers of strong credit quality and by obtaining guarantees from certain sovereign governments of the customer's obligations; however, many of our customers do not have or have not maintained, investment-grade credit ratings. Our generation businesses cannot always obtain government guarantees and if they do, the government may not have an investment grade credit rating. We have also located our plants in different geographic areas in order to mitigate the effects of regional economic downturns; however, there can be no assurance that our efforts will be effective.

Our renewable energy projects and other initiatives face considerable uncertainties.

Wind, solar, hydrogen, and energy storage projects are subject to substantial risks. Some of these business lines are dependent upon favorable regulatory incentives to support continued investment, and there is significant uncertainty about the extent to which such favorable regulatory incentives will be available in the future. In particular, in the U.S., AES' renewable energy generation growth strategy depends in part on federal, state and local government policies and incentives that support the development, financing, ownership and operation of renewable energy generation projects, including investment tax credits, production tax credits, accelerated depreciation, renewable portfolio standards, feed-in-tariffs and similar programs, renewable energy credit mechanisms, and tax exemptions. If these policies and incentives are changed or eliminated, or AES is unable to use them, there could be a material adverse impact on AES' U.S. renewable growth opportunities, including fewer future PPAs or lower prices in future PPAs, decreased revenues, reduced economic returns on certain project company investments, increased financing costs, and/or difficulty obtaining financing.

In addition,new tariffs, duties or other assessments could be imposed on the imports of solar cells, modules, batteries or other equipment utilized in our renewable energy projects.

Any such developments could impede the realization of our U.S. renewables strategy by resulting in, among other items, lack of a satisfactory market for the development and/or financing of our U.S. renewable energy projects, abandoning the development of certain U.S. renewable energy projects, a loss of our investments in the projects, and/or reduced project returns.

Furthermore, production levels for our wind and solar projects may be dependent upon adequate wind or sunlight resulting in volatility in production levels and profitability. For our wind projects, wind resource estimates are based on historical experience when available and on wind resource studies conducted by an independent engineer. These wind resource estimates are not expected to reflect actual wind energy production in any given year, but long-term averages of a resource.

As a result, these types of projects face considerable risk, including that favorable regulatory regimes expire or are adversely modified. At the development or acquisition stage, our ability to predict actual performance results may be hindered and the projects may not perform as predicted. There are also risks associated with the fact that some of these projects exist in markets where long-term fixed-price contracts for the major cost and revenue components may be unavailable, which in turn may result in these projects having relatively high levels of volatility. These projects can be capital-intensive and generally are designed with a view to obtaining third-party financing, which may be difficult to obtain. As a result, these capital constraints may reduce our ability to develop or obtain third-party financing for these projects.

Further, in the U.S., the tax credits associated with certain renewables projects are earned when the project is placed in service. Delays in executing our renewables projects can result in delays in recognizing those tax credits and adversely impact our short-term financial results.

Any of the above factors could have a material adverse effect on our business, financial condition, results of operations and prospects.

Our development projects are subject to substantial uncertainties.

We are in various stages of developing and constructing renewables projects and power plants. Certain of these projects have signed long-term contracts or made similar arrangements for the sale of electricity. Successful completion of the development of these projects depends upon overcoming substantial risks, including risks relating to siting, financing, engineering and construction, permitting, interconnection and transmission, governmental approvals, commissioning delays, supply chain related disruptions to our access to materials, or the potential for termination of the power sales contract as a result of a failure to meet certain milestones. Objections of or challenges by local communities or interest groups may delay or impede permitting for our development projects.

Additionally, in the U.S., there is a significant backlog of interconnection requests for renewables projects and the average time for receiving interconnection approvals is over four years, with significant variations across projects. There are also severe bottlenecks in the transmission system and the build-out of renewables to meet policy goals for renewable deployment will require substantial upgrades to the transmission network.

In certain cases, our subsidiaries may enter into obligations in the development process even though they have not yet secured financing, PPAs, or other important elements for a successful project. For example, our subsidiaries may instruct contractors to begin the construction process or seek to procure equipment without having financing, a PPA or critical permits in place (or enter into a PPA, procurement agreement or other agreement without agreed financing).

If the project does not proceed, our subsidiaries may retain certain liabilities. Furthermore, we may undertake significant development costs and subsequently 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 reach commercial operation. If development efforts are not successful, we may abandon certain projects, resulting in, writing off the costs incurred, expensing related capitalized development costs incurred and incurring additional losses associated with any related contingent liabilities.

Our acquisitions may not perform as expected.

Acquisitions have been a significant part of our growth strategy historically and more recently as we grow our renewables business. Although acquired businesses may have significant operating histories, we may have limited or no history of owning and operating certain of these businesses, and possibly limited or no experience operating in the country or region where these businesses are located. We also may encounter challenges in integrating and realizing the expected benefits of these acquisitions as well as integration or other one-time costs that are greater than expected. Such businesses may not generate sufficient cash flow to support the indebtedness incurred to acquire them or the capital expenditures needed to develop them; and the rate of return from such businesses may not justify our investment of capital to acquire them. In addition, some of these businesses may have been government owned and some may be operated as part of a larger integrated utility prior to their acquisition. If we were to acquire any of these types of businesses, there can be no assurance that we will be successful in transitioning them to private ownership or that we will not incur unforeseen obligations or liabilities.

The COVID-19 pandemic, or the future outbreak of any other highly infectious or contagious diseases, could impact our business and operations.

The COVID-19 pandemic has severely impacted global economic activity in recent years, including electricity and energy consumption. COVID-19 or another pandemic could have material and adverse effects on our results of operations, financial condition and cash flows due to, among other factors:

- further decline in customer demand as a result of general decline in business activity;
- further destabilization of the markets and decline in business activity negatively impacting customers' ability to pay for our services when due or at all, including downstream impacts, whereby the utilities' customers are unable to pay monthly bills or receiving a moratorium from payment obligations, resulting in inability on the part of utilities to make payments for power supplied by our generation companies;
- decline in business activity causing our commercial and industrial customers to experience declining revenues and liquidity difficulties that impede their ability to pay for power that we supply;
- government moratoriums or other regulatory or legislative actions that limit changes in pricing, delay or suspend customers' payment obligations or permit extended payment terms applicable to customers of our utilities or to our offtakers under power purchase agreements, in particular, to the extent that such measures are not mitigated by associated government subsidies or other support to address any shortfall or deficiencies in payments;
- claims by our PPA counterparties for delay or relief from payment obligations or other adjustments, including claims based on force majeure or other legal grounds;
- further decline in spot electricity prices;
- the destabilization of the markets and decline in business activity negatively impacting our customer growth in our service territories at our utilities;
- negative impacts on the health of our essential personnel and on our operations as a result of implementing stay-at-home, quarantine, curfew and other social distancing measures;
- delays or inability to access, transport and deliver fuel to our generation facilities due to restrictions on business operations or other factors affecting us and our third-party suppliers;
- delays or inability to access equipment or the availability of personnel to perform planned and unplanned maintenance or disruptions in supply chain, which can, in turn, lead to disruption in operations;
- a deterioration in our ability to ensure business continuity, including increased cybersecurity attacks related to the work-from-home environment;

- further delays to our construction projects, including at our renewables projects, and the timing of the completion of renewables projects;
- delay or inability to receive the necessary permits for our development projects due to delays or shutdowns of government operations;
- delays in achieving our financial goals, strategy and digital transformation;
- deterioration of the credit profile of The AES Corporation and/or its subsidiaries and difficulty accessing the capital and credit markets on favorable terms, or at all, and a severe disruption and instability in the global financial markets, or deterioration in credit and financing conditions, which could affect our access to capital necessary to fund business operations or address maturing liabilities on a timely basis;
- delays or inability to complete asset sales on anticipated terms or to redeploy capital as set forth in our capital allocation plans;
- increased volatility in foreign exchange and commodity markets;
- deterioration of economic conditions, demand and other related factors resulting in impairments to long-lived assets; and
- delay or inability in obtaining regulatory actions and outcomes that could be material to our business, including for recovery of COVID-19 related losses and the review and approval of our rates at our U.S. regulated utilities.

The impact of the COVID-19 pandemic also depends on factors, including the effectiveness and timing of updated vaccines to address new variants, the development of more virulent COVID-19 variants as well as third-party actions taken to contain its spread and mitigate its public health effects. A resurgence or material worsening of the COVID-19 pandemic could present material uncertainty that could adversely affect our generation facilities, transmission and distribution systems, development projects, energy storage sales by Fluence, and results of operations, financial condition and cash flows. The COVID-19 pandemic may also heighten many of the other risks described in this section.

Competition is increasing and could adversely affect us.

The power production markets in which we operate are characterized by numerous strong and capable competitors, many of whom may have extensive and diversified developmental or operating experience (including both domestic and international) and financial resources similar to, or greater than, ours. Further, in recent years, the power production industry has been characterized by strong and increasing competition with respect to both obtaining power sales agreements and acquiring existing power generation assets. In certain markets, these factors have caused reductions in prices contained in new power sales agreements and, in many cases, have caused higher acquisition prices for existing assets through competitive bidding practices. The evolution of competitive electricity markets and the development of highly efficient gas-fired power plants and renewables such as wind and solar have also caused, and could continue to cause, price pressure in certain power markets where we sell or intend to sell power. In addition, the introduction of low-cost disruptive technologies or the entry of non-traditional competitors into our sector and markets could adversely affect our ability to compete, which could have a material adverse effect on our businesses, operating results and financial condition.

Supplier and/or customer concentration may expose us to significant financial credit or performance risks.

We often rely on a single contracted supplier or a small number of suppliers for the provision of fuel, transportation of fuel and other services required for the operation of some of our facilities. If these suppliers cannot perform, we would seek to meet our fuel requirements by purchasing fuel at market prices, exposing us to market price volatility and the risk that fuel and transportation may not be available during certain periods at any price, which could adversely impact the profitability of the affected business and our results of operations, and could result in a breach of agreements with other counterparties, including, without limitation, offtakers or lenders. Further, our suppliers may source certain materials from areas impacted by the COVID-19 pandemic, which may cause delays and/or disruptions to our development projects or operations.

The financial performance of our facilities is dependent on the credit quality of, and continued performance by, suppliers and customers. At times, we rely on a single customer or a few customers to purchase all or a significant portion of a facility's output, in some cases under long-term agreements that account for a substantial percentage of the anticipated revenue from a given facility. Counterparties to these agreements may breach or may be unable to perform their obligations, due to bankruptcy, insolvency, financial distress or other factors. Furthermore, in the event of a bankruptcy or similar insolvency-type proceeding, our counterparty can seek to reject our existing PPA under the U.S. Bankruptcy Code or similar bankruptcy laws, including those in Puerto Rico. We may not be able to enter into replacement agreements on terms as favorable as our existing agreements, and may have to sell power at market prices. A counterparty's breach by of a PPA or other agreement could also result in the breach of other agreements, including the affected businesses debt agreements. Any failure of a supplier or customer to fulfill its contractual obligations could have a material adverse effect on our financial results.

We may incur significant expenditures to adapt our businesses to technological changes.

Emerging technologies 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, or may result in the obsolescence of certain of our operating assets. 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. Technological changes that could impact our businesses include:

- technologies that change the utilization of electric generation, transmission and distribution assets, including the expanded cost-effective utilization of distributed generation (e.g., rooftop solar and community solar projects), and energy storage technology;
- advances in distributed and local power generation and energy storage that reduce demand for large-scale renewable electricity generation or impact our customers' performance of long-term agreements; and
- more cost-effective batteries for energy storage, advances in solar or wind technology, and advances in alternative fuels and other alternative energy sources.

Emerging technologies may also allow new competitors to more effectively compete in our markets or disintermediate the services we provide our customers, including traditional utility and centralized generation services. If we incur significant expenditures in adapting to technological changes, fail to adapt to significant technological changes, fail to obtain access to important new technologies, fail to recover a significant portion of any remaining investment in obsolete assets, or if implemented technology fails to operate as intended, our businesses, operating results and financial condition could be materially adversely affected.

Cyber-attacks and data security breaches could harm our business.

Our business relies on electronic systems and network technologies to operate our generation, transmission and distribution infrastructure. We also use various financial, accounting and other infrastructure systems. Our infrastructure may be targeted by nation states, hacktivists, criminals, insiders or terrorist groups. In particular, there has been an increased focus on the U.S. energy grid believed to be related to the Russia/Ukraine conflict. Such an attack, by hacking, malware or other means, may interrupt our operations, cause property damage, affect our ability to control our infrastructure assets, cause the release of sensitive customer information or limit communications with third parties. Any loss or corruption of confidential or proprietary data through a breach may:

- impact our operations, revenue, strategic objectives, customer and vendor relationships;
- expose us to legal claims and/or regulatory investigations and proceedings;
- require extensive repair and restoration costs for additional security measures to avert future attacks;
- impair our reputation and limit our competitiveness for future opportunities; and
- impact our financial and accounting systems and, subsequently, our ability to correctly record, process and report financial information.

We have implemented measures to help prevent unauthorized access to our systems and facilities, including certain measures to comply with mandatory regulatory reliability standards. To date, cyber-attacks have not had a material impact on our operations or financial results. We continue to assess potential threats and vulnerabilities and make investments to address them, including global monitoring of networks and systems, identifying and implementing new technology, improving user awareness through employee security training, and updating our security policies as well as those for third-party providers. We cannot guarantee the extent to which our security measures will prevent future cyber-attacks and security breaches or that our insurance coverage will adequately cover any losses we may experience. Further, we do not control certain of joint ventures or our equity method investments and cannot guarantee that their efforts will be effective.

Certain of our businesses are sensitive to variations in weather and hydrology.

Our businesses are affected by variations in general weather patterns and unusually severe weather. Our businesses forecast electric sales based on best available information and expectations for weather, which represents a long-term historical average. While we also consider possible variations in normal weather patterns and potential impacts on our facilities and our businesses, there can be no assurance that such planning can prevent these impacts, which can adversely affect our business. Generally, demand for electricity peaks in winter and summer. Typically, when winters are warmer than expected and summers are cooler than expected, demand for energy is lower, resulting in less demand for electricity than forecasted. Significant variations from normal weather where our businesses are located could have a material impact on our results of operations.

Changes in weather can also affect the production of electricity at power generation facilities, including, but not limited to, our wind and solar facilities. For example, the level of wind resource affects the revenue produced by wind generation facilities. Because the levels of wind and solar resources are variable and difficult to predict, our results of operations for individual wind and solar facilities specifically, and our results of operations generally, may vary significantly from period to period, depending on the level of available resources. To the extent that resources are not available at planned levels, the financial results from these facilities may be less than expected. In addition, we are dependent upon hydrological conditions prevailing from time to time in the broad geographic regions in which our hydroelectric generation facilities are located. Changes in temperature, precipitation and snow pack conditions also could affect the amount and timing of hydroelectric generation.

To the extent that hydrological conditions result in droughts or other conditions negatively affect our hydroelectric generation business, such as has happened in Panama in 2019 and Brazil in 2021, our results of operations can be materially adversely affected. Additionally, our contracts in certain markets where hydroelectric facilities are prevalent may require us to purchase power in the spot markets when our facilities are unable to operate at anticipated levels and the price of such spot power may increase substantially in times of low hydrology.

Severe weather and natural disasters may present significant risks to our business.

Weather conditions directly influence the demand for electricity and natural gas and other fuels and affect the price of energy and energy-related commodities. In addition, severe weather and natural disasters, such as hurricanes, floods, tornadoes, icing events, earthquakes, dam failures and tsunamis can be destructive and could prevent us from operating our business in the normal course by causing power outages and property damage, reducing revenue, affecting the availability of fuel and water, causing injuries and loss of life, and requiring us to incur additional costs, for example, to restore service and repair damaged facilities, to obtain replacement power and to access available financing sources. Our power plants could be placed at greater risk of damage should changes in the global climate produce unusual variations in temperature and weather patterns, resulting in more intense, frequent and extreme weather events, including heatwaves, fewer cold temperature extremes, abnormal levels of precipitation resulting in river and coastal urban floods in North America or reduced water availability and increased flooding across Central and South America, and changes in coast lines due to sea level change.

Depending on the nature and location of the facilities and infrastructure affected, any such incident also could cause catastrophic fires; releases of natural gas, natural gas odorant, or other greenhouse gases; explosions, spills or other significant damage to natural resources or property belonging to third parties; personal injuries, health impacts or fatalities; or present a nuisance to impacted communities. Such incidents may also impact our business partners, supply chains and transportation, which could negatively impact construction projects and our ability to provide electricity and natural gas to our customers.

A disruption or failure of electric generation, transmission or distribution systems or natural gas production, transmission, storage or distribution systems in the event of a hurricane, tornado or other severe weather event, or otherwise, could prevent us from operating our business in the normal course and could result in any of the adverse consequences described above. At our businesses where cost recovery is available, recovery of costs to restore service and repair damaged facilities is or may be subject to regulatory approval, and any determination by the regulator not to permit timely and full recovery of the costs incurred. Any of the foregoing could have a material adverse effect on our business, financial condition, results of operations, reputation and prospects.

We do not control certain aspects of our joint ventures or our equity method investments.

We have invested in some joint ventures in which our subsidiaries share operational, management, investment and/or other control rights with our joint venture partners. In many cases, we may exert influence over the joint venture pursuant to a management contract, by holding positions on the board of the joint venture company or on management committees and/or through certain limited governance rights, such as rights to veto significant actions. However, we do not always have this type of influence over the project or business and we may be dependent on our joint venture partners or the management team of the joint venture to operate, manage, invest or otherwise control such projects or businesses. Our joint venture partners or the management team of our joint ventures may not have the level of experience, technical expertise, human resources, management and other attributes necessary to operate these projects or businesses optimally, and they may not share our business priorities. In some joint venture agreements in which we do have majority control of the voting securities, we have entered into shareholder agreements granting minority rights to the other shareholders.

The approval of joint venture partners also may be required for us to receive distributions of funds from jointly owned entities or to transfer our interest in projects or businesses. The control or influence exerted by our joint venture partners may result in operational management and/or investment decisions that are different from the decisions we would make and could impact the profitability and value of these joint ventures. In addition, if a joint venture partner becomes insolvent or bankrupt or is otherwise unable to meet its obligations to or share of liabilities for the joint venture, we may be responsible for meeting certain obligations of the joint ventures to the extent provided for in our governing documents or applicable law.

Further, we have a significant equity method investment in Fluence. As a publicly listed company, Fluence is governed by its own Board of Directors, whose members have fiduciary duties to the Fluence shareholders. While we have certain rights to appoint representatives to the Fluence Board of Directors, the interests of the Fluence shareholders, as represented by the Fluence Board of Directors, may not align with our interests or the interests of our securityholders. As of December 31, 2023, Fluence continues to report that a material weakness in its internal control over revenue recognition and related inventory has not yet been remediated. Such material weakness can impact the reliability of the Fluence financial information that we may include as part of our financial information.

In addition, we are generally dependent on the management team of our equity method investments to operate and control such projects or businesses. While we may exert influence pursuant to having positions on the boards of such investments and/or through certain limited governance rights, such as rights to veto significant actions, we do not always have this type of influence and the scope and impact of such influence may be limited. The management teams of our equity method investments may not have the level of experience, technical expertise, human resources, management and other attributes necessary to operate these projects or businesses optimally, and they may not share our business priorities, which could have a material adverse effect on value of such investments as well as our growth, business, financial condition, results of operations and prospects.

Fluctuations in currency exchange rates may impact our financial results and position.

Our exposure to currency exchange rate fluctuations results primarily from the translation exposure associated with the preparation of the Consolidated Financial Statements, as well as from transaction exposure associated with transactions in currencies other than an entity's functional currency. While the Consolidated Financial Statements are reported in U.S. dollars, the financial statements of several of our subsidiaries outside the U.S. are prepared using the local currency as the functional currency and translated into U.S. dollars by applying appropriate exchange rates. As a result, fluctuations in the exchange rate of the U.S. dollar relative to the local currencies where our foreign subsidiaries report could cause significant fluctuations in our results. In addition, while our foreign operations expenses are generally denominated in the same currency as corresponding sales, we have transaction exposure to the extent receipts and expenditures are not denominated in the subsidiary's functional currency. Moreover, the costs of doing business abroad may increase as a result of adverse exchange rate fluctuations.

We may not be adequately hedged against our exposure to changes in commodity prices or interest rates.

We routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity, fuel requirements and other commodities to lower our financial exposure related to commodity price fluctuations. As part of this strategy, we routinely utilize fixed price or indexed forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges. We also enter into contracts which help us manage our interest rate exposure. However, we may not cover the entire exposure of our assets or positions to market price or interest rate volatility, and the coverage will vary over time. Furthermore, the risk management practices we have in place may not always perform as planned. In particular, if prices of commodities or interest rates significantly deviate from historical prices or interest rates or if the price or interest rate volatility or distribution of these changes deviates from historical norms, our risk management practices may not protect us from significant losses. As a result, fluctuating commodity prices or interest rates may negatively impact our financial results to the extent we have unhedged or inadequately hedged positions. In addition, certain types of economic hedging activities may not qualify for hedge accounting under U.S. GAAP, resulting in increased volatility in our net income. The Company may also suffer losses associated with "basis risk," which is the difference in performance between the hedge instrument and the underlying exposure (usually the pricing node of the generation facility). Furthermore, there is a risk that the current counterparties to these arrangements may fail or are unable to perform part or all of their obligations under these arrangements, while we seek to protect against that by utilizing strong credit requirements and exchange trades, these protections may not fully cover the exposure in the event of a counterparty default. For our businesses with PPA pricing that does not completely pass through our fuel costs, the businesses attempt to manage the exposure through flexible fuel purchasing and timing of entry and terms of our fuel supply agreements; however, these risk management efforts may not be successful and the resulting commodity exposure could have a material impact on these businesses and/or our results of operations.

Our utilities businesses may experience slower growth in customers or in customer usage.

Customer growth and customer usage in our utilities businesses are affected by external factors, including mandated energy efficiency measures, demand side management requirements, and economic and demographic conditions, such as population changes, job and income growth, housing starts, new business formation and the overall level of economic activity. A lack of growth, or a decline, in the number of customers or in customer demand for electricity may cause us to not realize the anticipated benefits from significant investments and expenditures and have a material adverse effect on our business, financial condition, results of operations and prospects.

Some of our subsidiaries participate in defined benefit pension plans and their net pension plan obligations may require additional significant contributions.

We have 28 defined benefit plans, five at U.S. subsidiaries and the remaining plans at foreign subsidiaries, which cover substantially all of the employees at these subsidiaries. Pension costs are based upon a number of actuarial assumptions, including an expected long-term rate of return on pension plan assets, the expected life span of pension plan beneficiaries and the discount rate used to determine the present value of future pension obligations. Any of these assumptions could prove to be incorrect, resulting in a shortfall of pension plan assets compared to pension obligations under the pension plan. We periodically evaluate the value of the pension plan assets to ensure that they will be sufficient to fund the respective pension obligations. Downturns in the debt and/or equity markets, or the inaccuracy of any of our significant assumptions underlying the estimates of our subsidiaries' pension plan obligations, could result in a material increase in pension expense and future funding requirements. Our subsidiaries that participate in these plans are responsible for satisfying the funding requirements required by law in their respective jurisdictions for any shortfall of pension plan assets as compared to pension obligations under the pension plan, which may necessitate additional cash contributions to the pension plans that could adversely affect our and our subsidiaries' liquidity. See Item 7.—*Management's Discussion and Analysis—Critical Accounting Policies and Estimates—Pension and Other Postretirement Plans* and Note 15—*Benefit Plans* included in Item 8.—*Financial Statements and Supplementary Data*.

Impairment of long-lived assets would negatively impact our consolidated results of operations and net worth.

Long-lived assets are initially recorded at cost or fair value, are depreciated over their estimated useful lives, and are evaluated for impairment only when impairment indicators are present, such as deterioration in general economic conditions or our operating or regulatory environment; increased competitive environment; lower forecasted revenue; increase in fuel costs, particularly costs that we are unable to pass through to customers; increase in environmental compliance costs; negative or declining cash flows; loss of a key contract or customer, particularly when we are unable to replace it on equally favorable terms; developments in our strategy; divestiture of a significant component of our business; or adverse actions or assessments by a regulator. Any impairment of long-lived assets could have a material adverse effect on our business, financial condition, results of operations, and prospects.

Risks associated with Governmental Regulation and Laws

Our operations are subject to significant government regulation and could be adversely affected by changes in the law or regulatory schemes.

Our ability to predict, influence or respond appropriately to changes in law or regulatory schemes, including obtaining expected or contracted increases in electricity tariff or contract rates or tariff adjustments for increased expenses, could adversely impact our results of operations. Furthermore, changes in laws or regulations or changes in the application or interpretation of regulatory provisions in jurisdictions where we operate, particularly at our utilities where electricity tariffs are subject to regulatory review or approval, could adversely affect our business, including:

- changes in the determination, definition or classification of costs to be included as reimbursable or pass-through costs to be included in the rates we charge our customers, including but not limited to costs incurred to upgrade our power plants to comply with more stringent environmental regulations;
- changes in the determination of an appropriate rate of return on invested capital or that a utility's operating income or the rates it charges customers are too high, resulting in a rate reduction or consumer rebates;
- changes in the definition or determination of controllable or non-controllable costs;
- changes in tax law;
- changes in law or regulation that limit or otherwise affect the ability of our counterparties (including sovereign or private parties) to fulfill their obligations (including payment obligations) to us;
- changes in environmental law that impose additional costs or limit the dispatch of our generating facilities;
- changes in the definition of events that qualify as changes in economic equilibrium;
- changes in the timing of tariff increases;
- other changes in the regulatory determinations under the relevant concessions;
- other changes related to licensing or permitting which affect our ability to conduct business; or
- other changes that impact the short- or long-term price-setting mechanism in the our markets.

Furthermore, in many countries where we conduct business, the regulatory environment is constantly changing and it may be difficult to predict the impact of the regulations on our businesses. The impacts described above could also result from our efforts to comply with European Market Infrastructure Regulation, which includes regulations related to the trading, reporting and clearing of derivatives and similar regulations may be passed in other jurisdictions where we conduct business. Any of the above events may result in lower operating margins and financial results for the affected businesses.

Several of our businesses are subject to potentially significant remediation expenses, enforcement initiatives, private party lawsuits and reputational risk associated with CCR.

CCR generated at our current and former coal-fired generation plant sites, is currently handled and/or has been handled by: placement in onsite CCR ponds; disposal and beneficial use in onsite and offsite permitted, engineered landfills; use in various beneficial use applications, including encapsulated uses and structural fill; and used in permitted offsite mine reclamation. CCR currently remains onsite at several of our facilities, including in CCR ponds. The EPA's final CCR rule provides that enforcement actions can be commenced by the EPA, states, or territories, and private lawsuits. Compliance with the U.S. federal CCR rule; amendments to the federal CCR rule; or federal, state, territory, or foreign rules or programs addressing CCR may require us to incur substantial costs. In addition, the Company and our businesses may face CCR-related lawsuits in the United States and/or internationally that may expose us to unexpected potential liabilities. Furthermore, CCR-related litigation may also expose us to unexpected costs. In addition, CCR, and its production at several of our facilities, have been the subject of significant interest from environmental non-governmental organizations and have received national and local media attention. The direct and indirect effects of such media attention, and the demands of responding to and addressing it, may divert management time and attention. Any of the foregoing could have a material adverse effect on our business, financial condition, results of operations, reputation and prospects.

Some of our U.S. businesses are subject to the provisions of various laws and regulations administered by FERC, NERC and by state utility commissions that can have a material effect on our operations.

The AES Corporation is a registered electric utility holding company under the PUHCA 2005 as enacted as part of the EPAct 2005. PUHCA 2005 eliminated many of the restrictions that had been in place under the U.S. Public Utility Holding Company Act of 1935, while continuing to provide FERC and state utility commissions with enhanced access to the books and records of certain utility holding companies. PUHCA 2005 also creates additional potential challenges and opportunities. By removing some barriers to mergers and other potential combinations, the creation of large, geographically dispersed utility holding companies is more likely. These entities may have enhanced financial strength and therefore an increased ability to compete with us in the U.S.

FERC strongly encourages competition in wholesale electric markets. Increased market participation may have the effect of lowering our operating margins. Among other steps, FERC has encouraged RTOs and ISOs to develop demand response bidding programs as a mechanism for responding to peak electric demand and has also encouraged the integration of distributed energy resources. These programs may reduce the value of generation assets, particularly utility-scale projects. FERC is also encouraging the construction of new transmission infrastructure in accordance with provisions of EPAct 2005. Although new transmission lines may increase market opportunities, they may also increase the competition in our existing markets. Additionally, the market rules in the wholesale electric markets in which we operate continue to evolve in response to, among other things, increasing penetration by renewable energy resources and energy storage systems. For example, some wholesale electric market regions have either implemented or are considering changes to how resource adequacy or capacity attributes are allocated to intermittent generating resources. These changes could result in lower resource adequacy or capacity attribute revenues for our renewable generating facilities in these regions.

FERC has civil penalty authority over violations of any provision of Part II of the FPA, which concerns wholesale generation or transmission, as well as any rule or order issued thereunder. The FPA also provides for the assessment of criminal fines and imprisonment for violations under the FPA. This penalty authority was enhanced in EPAct 2005. As a result, FERC is authorized to assess a maximum penalty authority established by statute and such penalty authority has been and will continue to be adjusted periodically to account for inflation. With this expanded enforcement authority, violations of the FPA and FERC's regulations could potentially have more serious consequences than in the past.

Pursuant to EPAct 2005, the NERC has been certified by FERC as the Electric Reliability Organization ("ERO") to develop mandatory and enforceable electric system reliability standards applicable throughout the U.S. to improve the overall reliability of the electric grid. These standards are subject to FERC review and approval. Once approved, the reliability standards may be enforced by FERC independently, or, alternatively, by the ERO and regional reliability organizations with responsibility for auditing, investigating and otherwise ensuring compliance with reliability standards, subject to FERC oversight. Violations of NERC reliability standards are subject to FERC's penalty authority under the FPA and EPAct 2005.

Our U.S. utility businesses face significant regulation by their respective state utility commissions. The regulatory discretion is reasonably broad in both Indiana and Ohio and includes regulation as to services and facilities, the valuation of property, the construction, purchase, or lease of electric generating facilities, the classification of accounts, rates of depreciation, the increase or decrease in retail rates and charges, the issuance of certain securities, the acquisition and sale of some public utility properties or securities and certain other matters. These businesses face the risk of unexpected or adverse regulatory action which could have a material adverse effect on our results of operations, financial condition, and cash flows. See Item 1.—*Business—Utilities SBU*.

Our businesses are subject to stringent environmental laws, rules and regulations.

Our businesses are subject to stringent environmental laws and regulations by many federal, regional, state and local authorities, international treaties and foreign governmental authorities. These laws and regulations generally concern emissions into the air, effluents into the water, use of water, wetlands preservation, remediation of contamination, waste disposal, endangered species and noise regulation. Failure to comply with such laws and regulations or to obtain or comply with any associated environmental permits could result in fines or other sanctions. For example, in recent years, the EPA has issued NOVs to a number of coal-fired generating plants alleging wide-spread violations of the new source review and prevention of significant deterioration provisions of the CAA. The EPA has brought suit against and obtained settlements with many companies for allegedly making major modifications to a coal-fired generating units without proper permit approvals and without installing best available control technology. The primary focus of these NOVs has been emissions of SO_2 and NO_x and the EPA has imposed fines and required companies to install improved pollution control technologies to reduce such emissions. In addition, state regulatory agencies and non-governmental environmental organizations have pursued civil lawsuits against power plants in situations that have resulted in judgments and/or settlements requiring the installation of expensive pollution controls or the accelerated retirement of certain electric generating units.

Furthermore, Congress and other domestic and foreign governmental authorities have either considered or implemented various laws and regulations to restrict or tax certain emissions, particularly those involving air emissions and water discharges. These laws and regulations have imposed, and proposed laws and regulations could impose in the future, additional costs on the operation of our power plants. See Item 1.—*Business—Environmental and Land-Use Regulations*.

We have incurred and will continue to incur significant capital and other expenditures to comply with these and other environmental laws and regulations. Changes in, or new development of, environmental restrictions may force us to incur significant expenses or expenses that may exceed our estimates. There can be no assurance that we would be able to recover all or any increased environmental costs from our customers or that our business, financial condition, including recorded asset values or results of operations, would not be materially and adversely affected.

Concerns about GHG emissions and the potential risks associated with climate change have led to increased regulation and other actions that could impact our businesses.

International, federal and various regional and state authorities regulate GHG emissions and have created financial incentives to reduce them. In 2023, the Company's subsidiaries operated businesses that had total CO_2 emissions of approximately 34 million metric tonnes, approximately 11 million of which were emitted by our U.S. businesses (both figures are ownership adjusted). The Company uses CO_2 emission estimation methodologies supported by "The Greenhouse Gas Protocol" reporting standard on GHG emissions. For existing power generation plants, CO_2 emissions data are either obtained directly from plant continuous emission monitoring systems or calculated from actual fuel heat inputs and fuel type CO_2 emission factors. This estimate is based on a number of projections and assumptions that may prove to be incorrect, such as the forecasted dispatch, anticipated plant efficiency, fuel type, CO_2 emissions rates and our subsidiaries' achieving completion of such construction and development projects. While actual emissions may vary substantially; certain projects under construction or development when completed will increase emissions of our portfolio and therefore could increase the risks associated with regulation of GHG emissions.

There currently is no U.S. federal legislation imposing mandatory GHG emission reductions (including for CO_2) that affects our electric power generation facilities; however, in 2015, the EPA promulgated a rule establishing New Source Performance Standards for CO_2 emissions for newly constructed and modified/reconstructed fossil-fueled electric utility steam generating units larger than 25 MW and in 2018 proposed revisions to the rule. On May 23, 2023, the EPA published a proposed rule that would establish CO_2 emissions limits for certain new fossil-fuel fired stationary combustion turbines that commence construction or are modified after May 23, 2023. In 2019, the EPA promulgated the Affordable Clean Energy (ACE) Rule which would have replaced the EPA's 2015 Clean Power Plan Rule ("CPP"). However, on January 19, 2021, the D.C. Circuit vacated and remanded the ACE Rule. Subsequently, on June 30, 2022, the Supreme Court reversed the judgment of the D.C. Circuit Court and remanded for further proceedings consistent with its opinion, holding that the “generation shifting” approach in the CPP exceeded the authority granted to the EPA by Congress under Section 111(d) of the CAA. As a result of the June 30, 2022 Supreme Court decision, on October 27, 2022, the D.C. Circuit issued a partial mandate, holding pending challenges to the ACE Rule in abeyance. On May 23, 2023, the EPA published a proposed rule that would vacate the ACE Rule, establish emissions guidelines in the form of CO_2 emissions limitations for certain existing EGUs and would require states to develop State Plans that establish standards of performance for such EGUs that are at least as stringent as the EPA’s emissions guidelines. Depending on various EGU-specific factors, the bases of proposed emissions guidelines range from routine methods of operation to carbon capture and sequestration or co-firing low-GHG hydrogen starting in the 2030s. The impact of the results of further proceedings and potential future greenhouse gas emissions regulations remains uncertain, but it could be material.

In 2010, the EPA adopted regulations pertaining to GHG emissions that require new and existing sources of GHG emissions to potentially obtain new source review permits from the EPA prior to construction or modification. In 2016, the U.S. Supreme Court ruled that such permitting would only be required if such sources also must obtain a new source review permit for increases in other regulated pollutants. For further discussion of the regulation of GHG emissions, see Item 1.—*Business—Environmental and Land-Use Regulations—U.S. Environmental and Land-Use Legislation and Regulations—Greenhouse Gas Emissions* above. The Parties to the United Nations Framework Convention on Climate Change's Paris Agreement established a long-term goal of keeping the increase in global average temperature well below 2°C above pre-industrial levels. We anticipate that the Paris Agreement will continue the trend toward efforts to decarbonize the global economy and to further limit GHG emissions. The impact of GHG regulation on our operations will depend on a number of factors, including the degree and timing of GHG emissions reductions required under any such legislation or regulation, the cost of emissions reduction equipment and the price and availability of offsets, the extent to which market based compliance options are available, the extent to which our subsidiaries would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market and the impact of such legislation or regulation on the ability of our subsidiaries to recover costs incurred through rate increases or otherwise. The costs of compliance could be substantial.

Our non-utility, generation subsidiaries seek to pass on any costs arising from CO_2 emissions to contract counterparties. Likewise, our utility subsidiaries seek to pass on any costs arising from CO_2 emissions to customers. However, there can be no assurance that we will effectively pass such costs onto the contract counterparties or customers, respectively, or that the cost and burden associated with any dispute over which party bears such costs would not be burdensome and costly.

Furthermore, according to the Intergovernmental Panel on Climate Change, physical risks from climate change could include, but are not limited to, increased runoff and earlier spring peak discharge in many glacier and snow-fed rivers, warming of lakes and rivers, an increase in sea level, and changes and variability in precipitation and in the intensity and frequency of extreme weather events. Physical impacts may have the potential to significantly affect our business and operations. For example, extreme weather events could result in increased downtime and operation and maintenance costs at our electric power transmission and distribution assets and facilities. Variations in weather conditions, primarily temperature and humidity, would also be expected to affect the energy needs of customers. A decrease in energy consumption could decrease our revenues. In addition, while revenues would be expected to increase if the energy consumption of customers increased, such increase could prompt the need for additional investment in generation capacity.

In addition to government regulators, many groups, including politicians, environmentalists, the investor community and other private parties have expressed increasing concern about GHG emissions. New regulation, such as the initiatives in Chile and the Puerto Rico Energy Public Policy Act, may adversely affect our operations. See Item 7.—*Management's Discussion and Analysis—Key Trends and Uncertainties—Decarbonization Initiatives.* Responding to these decarbonization initiatives, including developments in our strategy in line with these initiatives may present challenges to our business. We may be unable to develop our renewables platform as quickly as anticipated. Further, we may be unable to dispose of coal-fired generation assets at anticipated prices, the estimated useful lives of these assets may decrease, and the value of such assets may be impaired. These initiatives could also result in the early retirement of coal-fired generation facilities, which could result in stranded costs if regulators disallow full recovery of investments.

Negative public perception of our GHG emissions could have an adverse effect on our relationships with third parties, our ability to attract additional customers, our business development opportunities, and our ability to access finance and insurance for our coal-fired generation assets.

In addition, plaintiffs previously brought tort lawsuits that were dismissed against the Company because of its subsidiaries' GHG emissions. Future similar lawsuits may prevail or result in damages awards or other relief. We may also be subject to risks associated with the impact on weather conditions. See *Certain of our businesses are sensitive to variations in weather and hydrology* and *Severe weather and natural disasters may present significant risks to our business and adversely affect our financial results* within this section for more information. If any of the foregoing risks materialize, costs may increase or revenues may decrease and there could be a material adverse effect on our results of operations, financial condition,cash flows and reputation.

Concerns about data privacy have led to increased regulation and other actions that could impact our businesses.

In the ordinary course of business, we collect and retain sensitive information, including personal identifiable information about customers, employees, customer energy usage and other information as well as information regarding business partners and other third parties, some of which may constitute confidential information. The theft, damage or improper disclosure of sensitive electronic data collected by us can subject us to penalties for violation of applicable privacy laws, subject us to claims from third parties, require compliance with notification and monitoring regulations, and harm our reputation. Although we maintain technical and organizational measures to protect personal identifiable information and other confidential information, breaches of, or disruptions to, our information technology systems could result in legal claims, liability or penalties under privacy laws or damage to operations or to the company's reputation, which could adversely affect our business.

We are also subject to various data privacy and security laws and regulations globally, as well as contractual requirements, as a result of having access to and processing confidential and personal identifiable information in the course of business. If we are unable to comply with applicable laws and regulations or with our contractual commitments, as well as maintain reliable information technology systems and appropriate controls with respect to privacy and security requirements, we may suffer regulatory consequences that could be costly or otherwise adversely affect our business. In addition, any actual or perceived failure on the part of one of our equity affiliates could have a material adverse impact on our results of operations and prospects.

Tax legislation initiatives or challenges to our tax positions could adversely affect us.

We operate in the U.S. and various non-U.S. jurisdictions and are subject to the tax laws and regulations of the U.S. federal, state and local governments and of many non-U.S. jurisdictions. From time to time, legislative measures may be enacted that could adversely impact our overall tax positions regarding income or other taxes, our effective tax rate or tax payments. For example, in the third quarter of 2022, the Inflation Reduction Act (the “IRA”) was signed into law in the United States. The IRA includes provisions that are expected to benefit the U.S. clean energy industry, including increases, extensions and/or new tax credits for onshore and offshore wind, solar, storage and hydrogen projects. We expect that the extension of the current solar investment tax credits ("ITCs"), as well as higher credits available for projects that satisfy wage and apprenticeship requirements, will increase demand for our renewables products. In the U.S., the IRA includes a 15% corporate alternative minimum tax based on adjusted financial statement income.

In the fourth quarter of 2022, the European Commission adopted an amended Directive on Pillar 2 establishing a global minimum tax at a 15% rate. The adoption requires EU Member States to transpose the Directive into their respective national laws by December 31, 2023 for the rules to come into effect as of January 1, 2024. During 2023, the Netherlands, Bulgaria, and Vietnam adopted legislation to implement Pillar 2 effective as of January 1, 2024. We will continue to monitor the issuance of draft legislation in other non-EU countries where the Company operates that are considering Pillar 2 amendments. The impact to the Company remains unknown but may be material.

Risks Related to our Indebtedness and Financial Condition

We have a significant amount of debt.

As of December 31, 2023, we had approximately $27 billion of outstanding indebtedness on a consolidated basis. All outstanding borrowings under The AES Corporation's revolving credit facility are unsecured. Most of the debt of The AES Corporation's subsidiaries, however, is secured by substantially all of the assets of those subsidiaries. A substantial portion of cash flow from operations must be used to make payments on our debt. Furthermore, since a significant percentage of our assets are used to secure this debt, this reduces the amount of collateral available for future secured debt or credit support and reduces our flexibility in operating these secured assets. This level of indebtedness and related security could have other consequences, including:

- making it more difficult to satisfy debt service and other obligations;
- increasing our vulnerability to general adverse industry and economic conditions, including adverse changes in foreign exchange rates, interest rates and commodity prices;
- reducing available cash flow to fund other corporate purposes and grow our business;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry;
- placing us at a competitive disadvantage to our competitors that are not as highly leveraged; and
- limiting, along with financial and other restrictive covenants relating to such indebtedness, our ability to borrow additional funds, pay cash dividends or repurchase common stock.

The agreements governing our indebtedness, including the indebtedness of our subsidiaries, limit, but do not prohibit the incurrence of additional indebtedness. If we were to become more leveraged, the risks described above would increase. Further, our actual cash requirements may be greater than expected and our cash flows may not be sufficient to repay all of the outstanding debt as it becomes due. In that event, we may not be able to borrow money, sell assets, raise equity or otherwise raise funds on acceptable terms to refinance our debt as it becomes due. In addition, our ability to refinance existing or future indebtedness will depend on the capital markets and our financial condition at that time. Any refinancing of our debt could result in higher interest rates or more onerous covenants that restrict our business operations. See Note 11—*Debt* included in Item 8.—*Financial Statements and Supplementary Data* for a schedule of our debt maturities.

The AES Corporation's ability to make payments on its outstanding indebtedness is dependent upon the receipt of funds from our subsidiaries.

The AES Corporation is a holding company with no material assets other than the stock of its subsidiaries. Almost all of The AES Corporation's cash flow is generated by the operating activities of its subsidiaries. Therefore, The AES Corporation's ability to make payments on its indebtedness and to fund its other obligations is dependent not only on the ability of its subsidiaries to generate cash, but also on the ability of the subsidiaries to distribute cash to it in the form of dividends, fees, interest, tax sharing payments, loans or otherwise.Our subsidiaries face various restrictions in their ability to distribute cash. Most of the subsidiaries are obligated, pursuant to loan agreements, indentures or non-recourse financing arrangements, to satisfy certain restricted payment covenants or other conditions before they may make distributions. Business performance and local accounting and tax rules may also limit dividend distributions. Subsidiaries in foreign countries may also be prevented from distributing funds as a result of foreign governments restricting the repatriation of funds or the conversion of currencies. Our subsidiaries are separate and distinct legal entities and, unless they have expressly guaranteed The AES Corporation's indebtedness, have no obligation, contingent or otherwise, to pay any amounts due pursuant to such debt or to make any funds available whether by dividends, fees, loans or other payments.

Existing and potential future defaults by subsidiaries or affiliates could adversely affect us.

We attempt to finance our domestic and foreign projects through non-recourse debt or "non-recourse financing" that requires the loans to be repaid solely from the project's revenues and provide that the repayment of the loans (and interest thereon) is secured solely by the capital stock, physical assets, contracts and cash flow of that project subsidiary or affiliate. As of December 31, 2023, we had approximately $27 billion of outstanding indebtedness on a consolidated basis, of which approximately $4.5 billion was recourse debt of the Parent Company and approximately $22.1 billion was non-recourse debt. In some non-recourse financings, the Parent Company has explicitly agreed, in the form of guarantees, indemnities, letters of credit, letter of credit reimbursement agreements and agreements to pay, to undertake certain limited obligations and contingent liabilities, most of which will only be effective or will be terminated upon the occurrence of future events. In the case of our U.S. renewables projects involving tax equity investors or purchasers of tax credits, we provide customary Parent Company or subsidiary guarantees to the tax equity investors or tax credit purchasers that require the Parent Company or subsidiary to bear the risk of any IRS recapture or disallowance of certain tax benefits they receive in connection with the transaction.

Certain of our subsidiaries are in default with respect to all or a portion of their outstanding indebtedness. The total debt classified as current in our Consolidated Balance Sheets related to such defaults was $325 million as of December 31, 2023. While the lenders under our non-recourse financings generally do not have direct recourse to the Parent Company, such defaults under non-recourse financings can:

- reduce the Parent Company's receipt of subsidiary dividends, fees, interest payments, loans and other sources of cash because a subsidiary will typically be prohibited from distributing cash to the Parent Company during the pendency of any default;
- trigger The AES Corporation's obligation to make payments under any financial guarantee, letter of credit or other credit support provided to or on behalf of such subsidiary;
- trigger defaults in the Parent Company's outstanding debt. For example, The AES Corporation's revolving credit facility and outstanding senior notes include events of default for certain bankruptcy related events involving material subsidiaries and relating to accelerations of outstanding material debt of material subsidiaries or any subsidiaries that in the aggregate constitute a material subsidiary; or
- result in foreclosure on the assets that are pledged under the non-recourse financings, resulting in write-downs of assets and eliminating any and all potential future benefits derived from those assets.

None of the projects that are in default are owned by subsidiaries that, individually or in the aggregate, meet the applicable standard of materiality in The AES Corporation's revolving credit facility or other debt agreements to trigger an event of default or permit acceleration under such indebtedness. However, as a result of future mix of distributions, write-down of assets, dispositions and other changes to our financial position and results of operations, one or more of these subsidiaries, individually or in the aggregate, could fall within the applicable standard of materiality and thereby upon an acceleration of such subsidiary's debt, trigger an event of default and possible acceleration of Parent Company indebtedness.

The AES Corporation has significant cash requirements and limited sources of liquidity.

The AES Corporation requires cash primarily to fund: principal repayments of debt, interest, dividends on our common stock, acquisitions, construction and other project commitments, other equity commitments (including business development investments); equity repurchases; taxes and Parent Company overhead costs. Our principal sources of liquidity are: dividends and other distributions from our subsidiaries, proceeds from financings at the Parent Company, and proceeds from asset sales. See Item 7.—*Management's Discussion and Analysis —Capital Resources and Liquidity*. We believe that these sources will be adequate to meet our obligations for the foreseeable future, based on a number of material assumptions about access the capital or commercial lending markets, the operating and financial performance of our subsidiaries, exchange rates, our ability to sell assets, and the ability of our subsidiaries to pay dividends and other distributions; however, there can be no assurance that these sources will be available when needed or that our actual cash requirements will not be greater than expected. In addition, our cash flow may not be sufficient to repay our debt obligations at maturity and we may have to refinance such obligations. There can be no assurance that we will be successful in obtaining such refinancing on acceptable terms.

Our ability to grow our business depends on our ability to raise capital on favorable terms.

We rely on the capital markets as a source of liquidity for capital requirements not satisfied by operating cash flows. Our ability to arrange for financing on either a recourse or non-recourse basis and the costs of such capital are dependent on numerous factors, some of which are beyond our control, including: general economic and capital market conditions; the availability of bank credit; the availability of tax equity investors; the financial condition, performance and prospects of AES as well as our competitors; and changes in tax and securities laws. Should access to capital not be available to us, we may have to sell assets or cease further investments, including the expansion or improvement of existing facilities, any of which would affect our future growth.

A downgrade in the credit ratings of The AES Corporation or its subsidiaries could adversely affect our access to the capital markets, interest expense, liquidity or cash flow.

If any of the credit ratings of the The AES Corporation and its subsidiaries were to be downgraded, our ability to raise capital on favorable terms could be impaired and our borrowing costs could increase. Furthermore, counterparties may no longer be willing to accept general unsecured commitments by The AES Corporation to provide credit support. Accordingly, we may be required to provide some other form of assurance, such as a letter of credit and/or collateral, to backstop or replace any credit support by The AES Corporation, which reduces our available credit. There can be no assurance that counterparties will accept such guarantees or other assurances.

The market price of our common stock may be volatile.

The market price and trading volumes of our common stock could fluctuate substantially due to factors including general economic conditions, conditions in our industry and our markets, environmental and economic developments, and general credit and capital markets conditions, as well as developments specific to us, including risks described in this section, failing to meet our publicly announced guidance or key trends and other matters described in Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations*.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

We recognize the importance of maintaining the safety and security of our people, systems, and data and have a holistic process, supported by our management and Board of Directors, for overseeing and managing cybersecurity and related risks.

AES' Chief Information Security Officer ("CISO") reports to our General Counsel and is the head of the Company's cybersecurity team. The CISO is responsible for assessing and managing our cyber risk management program. In this role, the CISO informs senior management regarding the prevention, detection, mitigation, and remediation of cybersecurity incidents and supervises such efforts. Our CISO has extensive experience assessing and managing cybersecurity programs and cybersecurity risk. Our CISO has served in that position since 2020.

The CISO manages a global team of cybersecurity professionals with broad experience and expertise, including in cybersecurity threat assessments and detection, cloud security, mitigation technologies, cybersecurity training, incident response, cyber forensics, insider threats and regulatory compliance. We rely on threat intelligence as well as other information obtained from governmental, public, or private sources, including contracted external consultants.

The Board of Directors oversees our cybersecurity risk exposures and the steps taken by management to monitor and mitigate cybersecurity risks. The CISO briefs the Board of Directors on the effectiveness of our cyber risk management program, typically on a semi-annual basis, and provides off-cycle updates as needed.

We consider cybersecurity as part of the enterprise risk process, including organized and structured reporting protocols. The prioritization of cybersecurity risk is aligned with overall risk management processes.

In addition, the Company's management team considers risks relating to cybersecurity, among other significant risks, and applicable mitigation plans to address such risks, at monthly performance review meetings. The Executive Leadership Team, as well as the Chief Accounting Officer, Chief Risk Officer, Vice President Global Financial Planning and Analytics, Treasurer, and Vice President Internal Audit, among others, participate in such meetings.

We have also established an Incident Response Team and associated protocol led by our CISO that governs our assessment, response, and notifications internally and externally upon the occurrence of a cybersecurity incident. Depending on the nature and severity of an incident, this protocol provides for escalating notification to our CEO and the Board (including the Chair of the Board and the Chair of the Financial Audit Committee). We regularly practice our incident response through executive tabletop exercises.

Our policies, standards, processes, and practices for assessing, identifying, and managing material risks from cybersecurity threats are integrated into our overall risk management program and are informed by frameworks established by the National Institute of Standards and Technology ("NIST") and other applicable industry standards. Our cybersecurity program addresses threats in a prioritized manner and, in particular, focuses on the following key areas:

- gap analysis to identify programmatic opportunities for improvement that can be incorporated into the cyber strategy;
- policies and standards that are annually reviewed and communicated;
- exceptions management and internal audits that support cybersecurity requirements through assessing control implementation risks; and
- monitoring and regular reporting of cyber resilience and posture at operational and strategic levels.

We engage assessors, consultants, auditors, or other third parties in connection with any such processes, including:

- external vulnerability assessments, including penetration tests;
- internal audit reviews;
- threat intelligence;
- incident management;
- audits of NERC-Critical Infrastructure Protection regulated environments by the NERC Registered Regional Entity; and
- program development support, as needed.

Our risk management program for third-party service providers includes risk-based assessments of their interactions with AES data and systems. We implement monitoring and response processes for key third-party service providers.

We provide awareness training to our employees to help identify, avoid, and mitigate cybersecurity threats. Our employees participate in training, including phishing exercises, monthly safety meetings, and an annual cybersecurity awareness update. We also periodically host tabletop exercises with management and other employees to practice rapid cyber incident response.

We face cybersecurity risks in connection with our business. Although such risks have not materially affected us to date, we have, from time to time, experienced threats to and breaches of our data and systems. For more information about the cybersecurity risks we face, see Item 1A.—*Risk Factors—Cyber-attacks and data security breaches could harm our business* included in this Form 10-K.

ITEM 2. PROPERTIES

We maintain offices in many places around the world, generally pursuant to the provisions of long- and short-term leases, none of which we believe are material. With a few exceptions, our facilities, which are described in Item 1—*Business* of this Form 10-K, are subject to mortgages or other liens or encumbrances as part of the project's related finance facility. In addition, the majority of our facilities are located on land that is leased. However, in a few instances, no accompanying project financing exists for the facility, and in a few of these cases, the land interest may not be subject to any encumbrance and is owned outright by the subsidiary or affiliate.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in certain claims, suits and legal proceedings in the normal course of business. The Company has accrued for litigation and claims when it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. The Company believes, based upon information it currently possesses and taking into account established reserves for estimated liabilities and its insurance coverage, that the ultimate outcome of these proceedings and actions is unlikely to have a material adverse effect on the Company's consolidated financial statements. It is reasonably possible, however, that some matters could be decided unfavorably to the Company and could require the Company to pay damages or make expenditures in amounts that could be material, but cannot be estimated as of December 31, 2023. Pursuant to SEC amendments Item 103 of SEC Regulation S-K, AES' policy is to disclose environmental legal proceedings to which a governmental authority is a party if such proceedings are reasonably expected to result in monetary sanctions of greater than or equal to $1 million.

In December 2001, Grid Corporation of Odisha ("GRIDCO") served a notice to arbitrate pursuant to the Indian Arbitration and Conciliation Act of 1996 on the Company, AES Orissa Distribution Private Limited ("AES ODPL"), and Jyoti Structures ("Jyoti") pursuant to the terms of the shareholders agreement between GRIDCO, the Company, AES ODPL, Jyoti and the Central Electricity Supply Company of Orissa Ltd. ("CESCO"), an affiliate of the Company. In the arbitration, GRIDCO asserted that a comfort letter issued by the Company in connection with the Company's indirect investment in CESCO obligates the Company to provide additional financial support to cover all of CESCO's financial obligations to GRIDCO. GRIDCO appeared to be seeking approximately $189 million in damages, plus undisclosed penalties and interest, but a detailed alleged damage analysis was not filed by GRIDCO. The Company counterclaimed against GRIDCO for damages. In June 2007, a 2-to-1 majority of the arbitral tribunal rendered its award rejecting GRIDCO's claims and holding that none of the respondents, the Company, AES ODPL, or Jyoti, had any liability to GRIDCO. The respondents' counterclaims were also rejected. A majority of the tribunal later awarded the respondents, including the Company, some of their costs relating to the arbitration. GRIDCO filed challenges of the tribunal's awards with the local Indian court. GRIDCO's challenge of the costs award has been dismissed by the court, but its challenge of the liability award remains pending. A hearing on the liability award has not taken place to date. The Company believes that it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

Pursuant to their environmental audit, AES Sul and AES Florestal discovered 200 barrels of solid creosote waste and other contaminants at a pole factory that AES Florestal had been operating. The conclusion of the audit was that a prior operator of the pole factory, Companhia Estadual de Energia ("CEEE"), had been using those contaminants to treat the poles that were manufactured at the factory. On their initiative, AES Sul and AES Florestal communicated with Brazilian authorities and CEEE about the adoption of containment and remediation measures. In March 2008, the State Attorney of the state of Rio Grande do Sul, Brazil filed a public civil action against AES Sul, AES Florestal and CEEE seeking an order requiring the companies to mitigate the contaminated area located on the grounds of the pole factory and an indemnity payment of approximately R$6 million ($1 million). In October 2011, the State Attorney filed a request for an injunction ordering the defendant companies to contain and remove the contamination immediately. The court granted injunctive relief on October 18, 2011, but determined that only CEEE was required to perform the removal work. In May 2012, CEEE began the removal work in compliance with the injunction. The case is now awaiting judgment. The removal and remediation costs are estimated to be approximately R$15 million to R$60 million ($3 million to $12 million), and there could be additional costs which cannot be estimated at this time. In June 2016, the Company sold AES Sul to CPFL Energia S.A. and as part of the sale, AES Guaiba, a holding company of AES Sul, retained the potential liability relating to this matter. The Company believes that there are meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In September 2015, AES Southland Development, LLC and AES Redondo Beach, LLC filed a lawsuit against the California Coastal Commission (the “CCC”) over the CCC's determination that the site of AES Redondo Beach included approximately 5.93 acres of CCC-jurisdictional wetlands. The CCC has asserted that AES Redondo Beach has improperly installed and operated water pumps affecting the alleged wetlands in violation of the California Coastal Act and Redondo Beach Local Coastal Program ("LCP"). Potential outcomes of the CCC determination could include an order requiring AES Redondo Beach to perform a restoration and/or pay fines or penalties. AES Redondo Beach believes that it has meritorious arguments concerning the underlying CCC determination, but there can be no assurances that it will be successful. On March 27, 2020, AES Redondo Beach, LLC sold the site to an unaffiliated third-party purchaser that assumed the obligations contained within these proceedings. On May 26, 2020, CCC staff sent AES a NOV directing AES to discontinue any operation of the water pumps in the alleged wetlands and to submit a Coastal Development Permit (“CDP”) application for the removal of the water pumps within the alleged wetlands. The NOV also directed AES to submit technical analysis regarding additional water pumps located within onsite electrical vaults and, if necessary, a CDP application for their continued operation. With respect to the vault pumps, AES provided the CCC with the requested analysis, and the CCC has not required further action. With respect to the pumps in the alleged wetlands, AES locked out those pumps to prevent further operation and submitted the CDP to the permitting authority, the City of Redondo Beach (the "City"), with respect to AES' plans to disable or remove the pumps. On October 14, 2020, the City deemed the CDP application to be complete and indicated a public hearing will be required. AES submitted all required information and waited for the City to continue processing the application. In December 2023, the City indicated it would continue processing the CDP application. AES will vigorously defend its interests with regard to the NOV, but we cannot predict the outcome of the matter at this time. However, settlements and litigated outcomes of Coastal Act and LCP claims alleged against other companies have required them to pay significant civil penalties and undertake remedial measures.

In October 2015, AES Indiana received an NOV alleging violations of the Clean Air Act (“CAA”), the Indiana State Implementation Plan (“SIP”), and the Title V operating permit related to alleged particulate and opacity violations at Petersburg Station Unit 3. In addition, in February 2016, AES Indiana received an NOV from the EPA alleging violations of New Source Review and other CAA regulations, the Indiana SIP, and the Title V operating permit at Petersburg Station. On August 31, 2020, AES Indiana reached a settlement with the EPA, the DOJ and the Indiana Department of Environmental Management (“IDEM”), resolving these purported violations of the CAA at Petersburg Station. The settlement agreement, in the form of a proposed judicial consent decree, was approved and entered by the U.S. District Court for the Southern District of Indiana on March 23, 2021, and includes, among other items, the following requirements: annual caps on NO_x and SO_2 emissions and more stringent emissions limits than AES Indiana's current Title V air permit; payment of civil penalties totaling $1.5 million; a $5 million environmental mitigation project consisting of the construction and operation of a new, non-emitting source of generation at the site; expenditure of $0.3 million on a state-only environmentally beneficial project to preserve local, ecologically-significant lands; and retirement of Units 1 and 2 prior to July 1, 2023.

In December 2018, a lawsuit was filed in Dominican Republic civil court against the Company, AES Puerto Rico, and three other AES affiliates. The lawsuit purports to be brought on behalf of over 100 Dominican claimants, living and deceased, and appears to seek relief relating to CCRs that were delivered to the Dominican Republic in 2004. The lawsuit generally alleges that the CCRs caused personal injuries and deaths and demands $476 million in alleged damages. The lawsuit does not identify, or provide any supporting information concerning, the alleged injuries of the claimants individually. Nor does the lawsuit provide any information supporting the demand for damages or explaining how the quantum was derived. The relevant AES companies believe that they have meritorious defenses to the claims asserted against them and will defend themselves vigorously in this proceeding; however, there can be no assurances that they will be successful in their efforts.

In February 2019, a separate lawsuit was filed in Dominican Republic civil court against the Company, AES Puerto Rico, two other AES affiliates, and an unaffiliated company and its principal. Subsequently, the claimants withdrew the lawsuit with respect to AES Puerto Rico. The lawsuit remains pending against the other AES defendants (“AES Defendants”) and the unaffiliated defendants. The lawsuit purports to be brought on behalf of over 200 Dominican claimants, living and deceased, and appears to seek relief relating to CCRs that were delivered to the Dominican Republic in 2003 and 2004. The lawsuit generally alleges that the CCRs caused personal injuries and deaths and demands over $900 million in alleged damages. The lawsuit does not identify, or provide any supporting information concerning, the alleged injuries of the claimants individually, nor does the lawsuit provide any information supporting the demand for damages or explaining how the quantum was derived. In August 2020, at the request of the relevant AES companies, the case was transferred to a different civil court ("Civil Court"). Preliminary hearings have taken place. The parties are awaiting the Civil Court's ruling on the AES Defendants' motions to dismiss the lawsuit. The AES Defendants believe that they have meritorious defenses to the claims asserted against them and will defend themselves vigorously in this proceeding; however, there can be no assurances that they will be successful in their efforts.

In October 2019, the Superintendency of the Environment (the "SMA") notified AES Andes of certain alleged breaches associated with the environmental permit of the Ventanas Complex, initiating a sanctioning process through Exempt Resolution N° 1 / ROL D-129-2019. The alleged charges include exceeding generation limits, failing to reduce emissions during episodes of poor air quality, exceeding limits on discharges to the sea, and exceeding noise limits. AES Andes has submitted a proposed “Compliance Program” to the SMA for the Ventanas Complex. The latest version of this Compliance Program was submitted on May 26, 2021. On December 30, 2021, the Compliance Program was approved by the SMA. However an ex officio action was brought by the SMA due to alleged exceedances of generation limits, which would require the Company to reduce SO_2, NO_X and PM emissions in order to achieve the emissions offset established in the Compliance Program. On January 6, 2022, AES Andes filed a reposition with the SMA seeking modification of the means for compliance with the ex officio action. On January 17, 2023, the SMA approved street paving measures, or alternatively a program providing heaters for community members, as the means to satisfy the air emissions offsets in the approved Compliance Plan. The cost of proposed Compliance Program is approximately $10.8 million USD. On April 21, 2023, the SMA notified AES Andes of a resolution alleging an additional “serious” non-compliance of the Ventanas Complex failing to reduce emissions during episodes of poor air quality. On May 24, 2023, AES Andes submitted disclaimers to the SMA in response to this resolution. AES Andes plans to vigorously defend itself through the administrative process, but there are no guarantees that it will be successful. Fines are possible if AES Andes is unsuccessful in its defense of the April 2023 resolution and/or if the SMA determines there is an unsatisfactory execution of the Compliance Program approved in connection with the October 2019 sanctioning process.

In March 2020, Mexico’s Comisión Federal de Electricidad (“CFE”) served an arbitration demand upon AES Mérida III. CFE made allegations that AES Mérida III was in breach of its obligations under a power and capacity purchase agreement (“Contract”) between the two parties, which allegations related to CFE’s own failure to provide fuel within the specifications of the Contract. CFE sought to recover approximately $200 million in payments made to AES Mérida under the Contract as well as approximately $480 million in alleged damages for having to acquire power from alternative sources in the Yucatan Peninsula. AES Mérida filed an answer denying liability to CFE and asserted a counterclaim for damages due to CFE’s breach of its obligations. The evidentiary hearing took place in November 2021. Closing arguments were heard in May 2022. In November 2022, the arbitration Tribunal issued its decision in the case, rejecting CFE’s claims for damages and granting AES Mérida a net amount of damages on AES Mérida’s counterclaims ("Award"). There are ongoing proceedings in the Mexican courts concerning AES Mérida's attempt to enforce the Award and CFE's attempt to challenge the Award. AES Mérida believes that it has meritorious claims and defenses and will assert them vigorously in this dispute; however, there can be no assurances that it will be successful in its efforts.

On May 12, 2021, the Mexican Federal Attorney for Environmental Protection (the “Authority”) initiated an environmental audit at the TEP thermal generating facility. On January 20, 2023 TEP was notified of the resolution issued by the Authority, which alleges breaches of air emission regulations, including the failure to submit reports. The resolution imposes a fine of $27,615,140 pesos (approximately USD $1.6 million). On March 3, 2023, the facility filed a nullity judgment to challenge such resolution, which has been admitted by the local judge with an injunction granted against execution of the proposed fine during the course of the underlying proceedings. However, the local tax authority rejected receiving the bond that is required to guarantee the injunction, and as a result, on September 18, 2023 TEP filed a complaint seeking to compel the tax authority to accept the bond and recognize the validity of the injunction. The Specialized Chamber has not issued a response to the complaint, and therefore on January 12, 2024, TEP filed a request for the Specialized Chamber to rule on the admission of the complaint. On February 2, 2024, TEP filed an amparo lawsuit on the basis that no resolution has been issued regarding TEP's May 2023 filing with the Chamber to inform if the Authority had submitted its response to the nullity lawsuit, and if not, to declare that the Authority's right precluded. The Company believes that it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In February 2022, a lawsuit was filed in Dominican Republic civil court against the Company. The lawsuit purports to be brought on behalf of over 425 Dominican claimants, living and deceased, and appears to seek relief relating to CCRs that were delivered to the Dominican Republic in 2003 and 2004. The lawsuit generally alleges that the CCRs caused personal injuries and deaths and demands over $600 million in alleged damages. The lawsuit does not identify or provide any supporting information concerning the alleged injuries of the claimants individually. Nor does the lawsuit provide any information supporting the demand for damages or explaining how the quantum was derived. The Company believes that it has meritorious defenses to the claims asserted against it and will defend itself vigorously in this proceeding; however, there can be no assurances that it will be successful in its efforts.

On July 25, 2022, AES Puerto Rico, LP (“AES-PR”) received from the EPA an NOV alleging certain violations of the CAA at AES-PR’s coal-fired power facility in Guayama, Puerto Rico. The NOV alleges AES-PR exceeded an emission limit and did not continuously operate certain monitoring equipment, conduct certain analyses and testing, maintain complete records, and submit certain reports as required by the EPA’s Mercury and Air Toxics Standards. The NOV further alleges AES-PR did not comply fully with the facility’s Title V operating permit. AES-PR is engaging in discussions with the EPA about the NOV. AES-PR will defend its interests, but we cannot predict the outcome of this matter at this time. However, settlements and litigated outcomes of CAA claims alleged against other coal-fired power plants have required companies to pay civil penalties and undertake remedial measures.

In April 2022, the Superintendency of the Environment (the "SMA") notified AES Andes of certain alleged breaches associated with the construction of the Mesamávida wind project, initiating a sanctioning process. The alleged charges include untimely implementation of road improvement measures and road use schedules and the failure to identify all noise receptors closest to the first construction phases of the project. On June 23, 2022, the SMA addressed the charges to Energía Eólica Mesamávida SpA. On June 28, 2022, Energía Eólica Mesamávida SpA submitted a proposed compliance program, with an estimated cost of $4.3 million, which was subsequently approved by the SMA. On November 9, 2022, opponents to the project submitted before the Third Environmental Court a judicial action challenging the approval of this compliance program. On March 7, 2023, the Third Environmental Court rejected the third-party judicial action against the Compliance Program. The deadline to appeal the decision has passed and no appeals were submitted. The Company has fulfilled the required actions of the Compliance Program; however, opponents to project have submitted claims before the SMA challenging the fulfillment of the Compliance Program. If the SMA determines there is an unsatisfactory execution of the compliance program, fines are possible.

In June 2020, the Energy Regulatory Commission of Mexico passed resolution RES/894/2020 ("Resolution 894"), which attempts to increase the wheeling tariffs that are paid by TEG and TEP to CFE. The increase for the relevant period (July 2020 through March 2024) would have been over $90 million according to current estimates. In October 2022, TEG and TEP initiated a challenge of the constitutionality of the resolution. In February 2024, the relevant First Collegiate Court of Mexico ruled in favor of TEG and TEP and determined that they do not need to pay increased wheeling tariffs under Resolution 894. If TEG and TEP are ever required to pay increased wheeling tariffs in the future, they will seek to enforce their respective contractual rights to pass-through the tariff increases to their respective offtakers.

On January 26, 2023, the SMA notified Alto Maipo SpA of four alleged charges relating to the Alto Maipo facility, all which are categorized by the SMA as “serious.” The alleged charges include untimely completion of intake works and insufficient capture by the provisional works, irrigation water outlet and canal contemplated by an agreement with local communities; non-compliance with the details of the forest management plans and intervention in unauthorized areas; construction of a road in a restricted paleontological area; and unlawful moving of fauna. On February 16, 2023, the Alto Maipo project submitted a compliance program to which the SMA provided observations. On June 6, 2023, Alto Maipo responded to the SMA's observations by submitting a revised compliance program, which is currently under consideration by the SMA. In late June and early July 2023, third-party opponents submitted observations to the compliance program, claiming that the proposal to address the intake works charges is inadequate. Alto Maipo completed its submission of responses to these third-party observations in August 2023, and subsequently, new, additional observations were submitted by opponents to the project. In December 2023, Alto Maipo submitted responses to the opponents' latest observations. Review by the SMA is still pending. The costs of any such compliance program are uncertain. If a compliance program is not approved by or executed to the satisfaction of the SMA, fines, revocation of the facility’s RCA environmental permit approved by the SMA, or closure are possible outcomes for such alleged serious violations under applicable regulations.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Recent Sales of Unregistered Securities

None.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Stock Repurchase Program — The Board authorization permits the Parent Company to repurchase stock through a variety of methods, including open market repurchases and/or privately negotiated transactions. There can be no assurances as to the amount, timing or prices of repurchases, which may vary based on market conditions and other factors. The Stock Repurchase Program does not have an expiration date and can be modified or terminated by the Board of Directors at any time. The cumulative repurchases from the commencement of the Stock Repurchase Program in July 2010 through December 31, 2023 totaled 154.3 million shares for a total cost of $1.9 billion, at an average price per share of $12.12 (including a nominal amount of commissions). As of December 31, 2023, $264 million remained available for repurchase under the Stock Repurchase Program. No repurchases were made by The AES Corporation of its common stock in 2023, 2022, and 2021.

Market Information

Our common stock is traded on the New York Stock Exchange under the symbol "AES."

Dividends

The Parent Company commenced a quarterly cash dividend in the fourth quarter of 2012. The Parent Company has increased this dividend annually and the quarterly per-share cash dividends for the last three years are displayed below.

Commencing the fourth quarter of	**2023**	**2022**	**2021**
Cash dividend	$0.1725	$0.1659	$0.1580

The fourth quarter 2023 cash dividend is to be paid in the first quarter of 2024. There can be no assurance the AES Board will declare a dividend in the future or, if declared, the amount of any dividend. Our ability to pay dividends will also depend on receipt of dividends from our various subsidiaries across our portfolio.

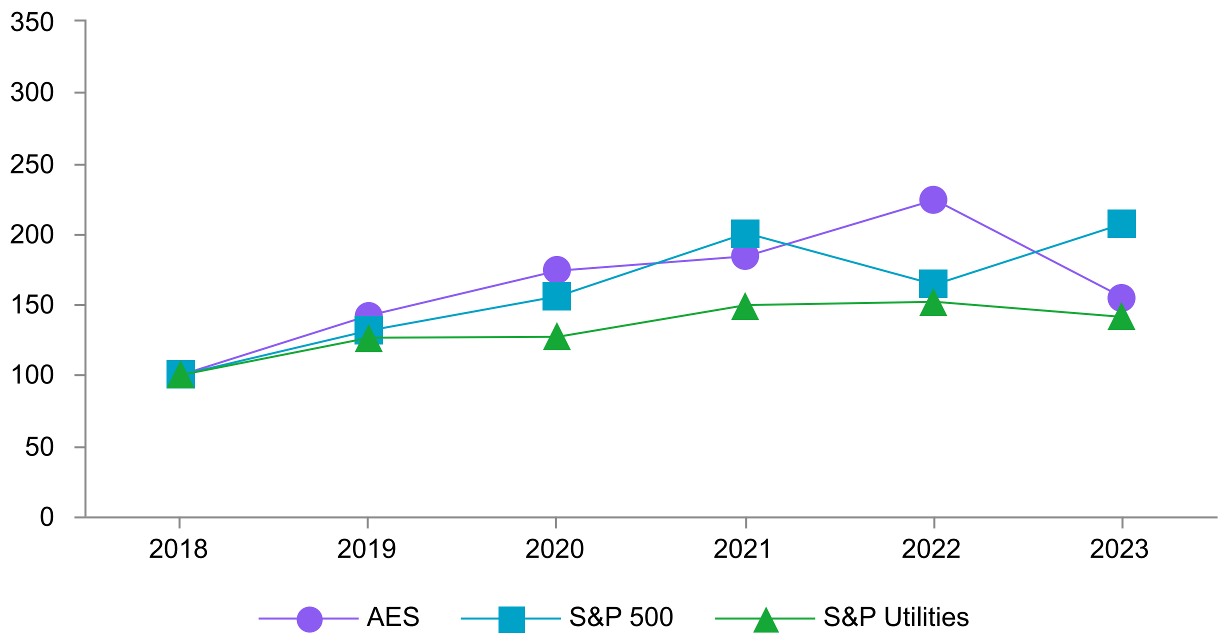
Under the terms of our revolving credit facility, which we entered into with a commercial bank syndicate, we have limitations on our ability to pay cash dividends and/or repurchase stock. Our subsidiaries' ability to declare and pay cash dividends to us is also subject to certain limitations contained in the project loans, governmental provisions and other agreements to which our subsidiaries are subject. See the information contained under Item 12.—*Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters—Securities Authorized for Issuance under Equity Compensation Plans* of this Form 10-K.

Holders

As of February 22, 2024, there were approximately 3,395 record holders of our common stock.

Performance Graph

THE AES CORPORATION
PEER GROUP INDEX/STOCK PRICE PERFORMANCE



Source: Bloomberg

We have selected the Standard and Poor's ("S&P") 500 Utilities Index as our peer group index. The S&P 500 Utilities Index is a published sector index comprising the 30 electric and gas utilities included in the S&P 500.

The five year total return chart assumes $100 invested on December 31, 2018 in AES Common Stock, the S&P 500 Index and the S&P 500 Utilities Index. The information included under the heading *Performance Graph* shall not be considered "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 or incorporated by reference in any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934.

ITEM 6. [RESERVED]

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

For discussion of the Company's year ended December 31, 2022 compared to the year ended December 31, 2021, refer to Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations* in Exhibit 99.1 of the Form 8-K filed with the SEC on May 8, 2023.

Executive Summary

In 2023, AES delivered on its strategic and financial objectives. We completed construction or the acquisition of 3.5 GW of renewables and energy storage, and signed long-term PPAs for an additional 5.6 GW of new renewable energy. See *Overview of our Strategy* included in Item 1.—*Business* of this Form 10-K for further information.

Compared with last year, net loss decreased $323 million, from $505 million to $182 million primarily as a result of favorable contributions at the Utilities, New Energy Technologies, and Renewables SBUs, partially offset by lower contributions from LNG transactions versus 2022 at the Energy Infrastructure SBU.

Adjusted EBITDA, a non-GAAP measure, decreased $119 million, from $2,931 million to $2,812 million, mainly driven by favorable LNG transactions in the prior year, lower contract prices, and higher fixed costs at the Energy Infrastructure SBU; partially offset by favorable weather conditions and new businesses at the Renewables SBU, higher contributions at the Utilities SBU due to the deferral of purchased power costs, higher revenues under a PPA termination agreement at the Energy Infrastructure SBU, and lower losses from affiliates at the New Energy Technologies SBU due to improved margins on a new product line.

Adjusted EBITDA with Tax Attributes, a non-GAAP measure, increased $225 million, from $3,198 million to $3,423 million, primarily due to higher realized tax attributes driven by more renewables projects placed in service, as well as impact from the drivers above.

Compared with last year, diluted earnings per share from continuing operations increased $1.16, from a loss of $0.82 in 2022 to earnings of $0.34 in 2023. This increase is mainly driven by lower goodwill impairments in the current year, higher contributions from renewables projects placed in service in the current year, the current year gain on sale of shares in Fluence, and higher contributions at the Utilities SBU due to the deferral of purchased power costs; partially offset by lower contributions from LNG transactions versus 2022, and higher unrealized foreign currency losses at the Energy Infrastructure SBU.

Adjusted EPS, a non-GAAP measure, increased $0.09 from $1.67 to $1.76, mainly driven by higher contributions from renewables projects placed in service in the current year, higher contributions at the Utilities SBU, and lower losses of affiliates at the New Energy Technologies SBU; partially offset by lower contributions from the Energy Infrastructure SBU and higher Parent Company interest.

Review of Consolidated Results of Operations

Years Ended December 31, (in millions, except per share amounts)	2023	2022	$ Change	% Change
Revenue:				
Renewables SBU	$ 2,339	$ 1,893	$ 446	24%
Utilities SBU	3,495	3,617	(122)	-3%
Energy Infrastructure SBU	6,836	7,204	(368)	-5%
New Energy Technologies SBU	76	3	73	NM
Corporate and Other	138	116	22	19%
Eliminations	(216)	(216)	—	—%
Total Revenue	12,668	12,617	51	—%
Operating Margin:				
Renewables SBU	492	528	(36)	-7%
Utilities SBU	433	379	54	14%
Energy Infrastructure SBU	1,418	1,535	(117)	-8%
New Energy Technologies SBU	(9)	(7)	(2)	29%
Corporate and Other	239	182	57	31%
Eliminations	(69)	(69)	—	—%
Total Operating Margin	2,504	2,548	(44)	-2%
General and administrative expenses	(255)	(207)	(48)	23%
Interest expense	(1,319)	(1,117)	(202)	18%
Interest income	551	389	162	42%
Loss on extinguishment of debt	(63)	(15)	(48)	NM
Other expense	(99)	(68)	(31)	46%
Other income	89	102	(13)	-13%
Gain (loss) on disposal and sale of business interests	134	(9)	143	NM
Goodwill impairment expense	(12)	(777)	765	-98%
Asset impairment expense	(1,067)	(763)	(304)	40%
Foreign currency transaction losses	(359)	(77)	(282)	NM
Other non-operating expense	—	(175)	175	-100%
Income tax benefit (expense)	(261)	(265)	4	-2%
Net equity in losses of affiliates	(32)	(71)	39	-55%
LOSS FROM CONTINUING OPERATIONS	(189)	(505)	316	-63%
Gain from disposal of discontinued businesses, net of income tax benefit (expense) of $7, $0, and $-1, respectively	7	—	7	NM
NET LOSS	(182)	(505)	323	-64%
Less: Net loss (income) attributable to noncontrolling interests and redeemable stock of subsidiaries	431	(41)	472	NM
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ 249	$ (546)	$ 795	NM
AMOUNTS ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:				—%
Income (loss) from continuing operations, net of tax	$ 242	$ (546)	$ 788	NM
Income from discontinued operations, net of tax	7	—	7	NM
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ 249	$ (546)	$ 795	NM
Net cash provided by operating activities	$ 3,034	$ 2,715	$ 319	12%

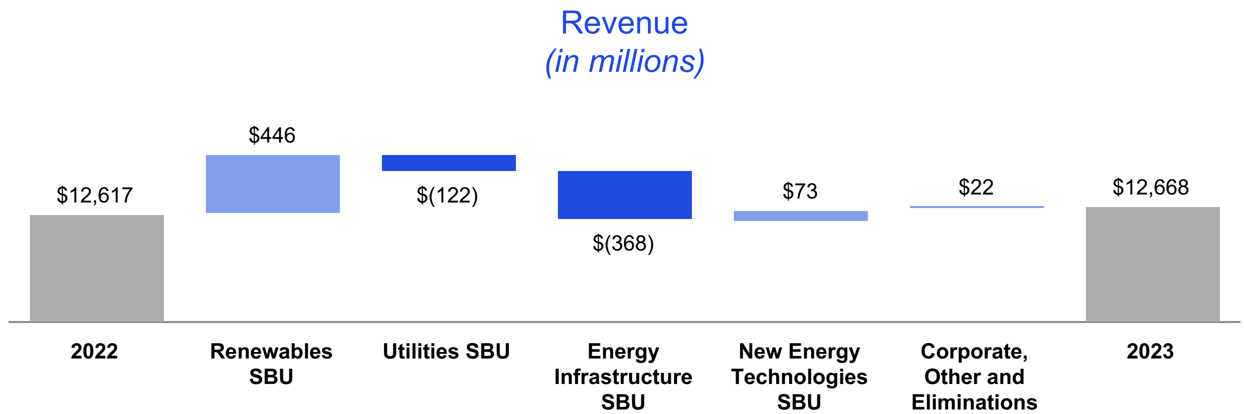
Components of Revenue, Cost of Sales and Operating Margin — Revenue includes revenue earned from the sale of energy from our utilities and the production and sale of energy from our generation plants, which are classified as regulated and non-regulated, respectively, on the Consolidated Statements of Operations. Revenue also includes the gains or losses on derivatives associated with the sale of electricity.

Cost of sales includes costs incurred directly by the businesses in the ordinary course of business. Examples include electricity and fuel purchases, operations and maintenance costs, depreciation and amortization expenses, bad debt expense and recoveries, and general administrative and support costs (including employee-related costs directly associated with the operations of the business). Cost of sales also includes the gains or losses on derivatives (including embedded derivatives other than foreign currency embedded derivatives) associated with the purchase of electricity or fuel.

Operating margin is defined as revenue less cost of sales.

Consolidated Revenue and Operating Margin

Year Ended December 31, 2023

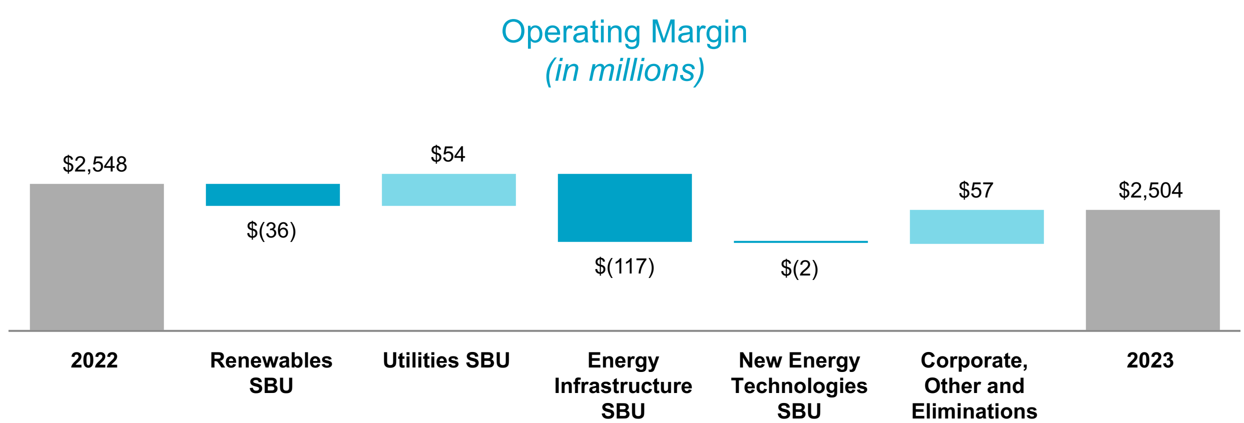


Consolidated Revenue — Revenue increased $51 million in 2023 compared to 2022, driven by:

- $446 million at Renewables driven by higher spot sales at higher prices, and new projects placed in service; partially offset by unrealized derivative losses; and
- $73 million at New Energy Technologies mainly driven by the sale of the Fallbrook project in March 2023.

These favorable impacts were partially offset by decreases of:

- $368 million at Energy Infrastructure driven by prior year favorable LNG transactions, lower contract energy sales due to lower prices, lower CO_2 purchases passed through due to lower production, lower generation, and the impact of the devaluation of the Argentine peso; partially offset by unrealized gains resulting mainly from derivatives as part of our commercial hedging strategy, and higher revenues due to a PPA termination agreement; and
- $122 million at Utilities mainly driven by lower demand due to milder weather in Indiana and Ohio; partially offset by higher TDSIC rider and transmission revenues, and higher demand due to extreme heat in El Salvador.



Consolidated Operating Margin — Operating margin decreased $44 million, or 2%, in 2023 compared to 2022, driven by:

- $117 million at Energy Infrastructure primarily driven by prior year favorable LNG transactions, lower contract energy sales due to lower prices, lower dispatch driven by lower demand, higher fixed costs, and a prior year one-time revenue recognition driven by a reduction in a project's expected completion costs; partially offset by unrealized gains resulting mainly from derivatives as part of our commercial hedging strategy, and higher revenues due to a PPA termination agreement; and

- $36 million at Renewables mainly driven by higher fixed costs due to an accelerated growth plan and unrealized derivative losses; partially offset by new projects placed in service, better hydrology, and higher wind availability, resulting in higher renewable energy generation.

These unfavorable impacts were partially offset by increases of:

- $57 million at Corporate and Other primarily driven by a decrease in reserve for losses and higher premiums earned by the AES self-insurance company; and
- $54 million at Utilities primarily driven by the deferral of purchased power costs in the current year, which were recognized in the prior year, associated with the ESP 4 approval, an increase in transmission and TDSIC rider revenues, higher demand due to extreme heat in El Salvador, and a regulatory settlement in the prior year; partially offset by the impact of milder weather in Indiana and Ohio, and higher fixed costs.

See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—SBU Performance Analysis* of this Form 10-K for additional discussion and analysis of operating results for each SBU.

Consolidated Results of Operations — Other

General and administrative expenses

General and administrative expenses include expenses related to corporate staff functions and initiatives, executive management, finance, legal, human resources, and information systems, as well as global development costs.

General and administrative expenses increased $48 million, or 23%, to $255 million in 2023 compared to $207 million in 2022, primarily due to increased business development activity.

Interest expense

Interest expense increased $202 million, or 18%, to $1.3 billion in 2023, compared to $1.1 billion in 2022, primarily due to new debt issued at the Renewables, Energy Infrastructure, and Utilities SBUs, and a higher weighted average interest rate and debt balance at the Parent Company; partially offset by higher capitalized interest at the Renewables SBU.

Interest income

Interest income increased $162 million, or 42%, to $551 million in 2023, compared to $389 million in 2022 primarily due to higher average interest rates and short-term investments at the Energy Infrastructure and Renewables SBUs and the Parent Company; partially offset by the prior year sales-type lease receivable adjustment at the Alamitos Energy Center.

Loss on extinguishment of debt

Loss on extinguishment of debt increased $48 million to $63 million in 2023, compared to $15 million in 2022. This increase was primarily due to losses of $47 million and $10 million due to prepayments at AES Andes and AES Hispanola Holdings BV, respectively, partially offset by a prior year refinancing at AES Renewable Holdings, resulting in a loss of $12 million.

See Note 11—*Debt* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Other income

Other income decreased $13 million, or 13%, to $89 million in 2023, compared to $102 million in 2022 primarily due to the prior year gain on remeasurement of our existing investment in 5B, which is accounted for using the measurement alternative, and the prior year insurance proceeds primarily associated with property damage at TermoAndes; partially offset by the current year gain on remeasurement of contingent consideration at AES Clean Energy.

Other expense

Other expense increased $31 million, or 46%, to $99 million in 2023, compared to $68 million in 2022 primarily driven by impairments of inventory due to planned early plant closures at Ventanas 2, Norgener, and Warrior Run, as well as higher losses on commencement of sales-type leases at AES Renewable Holdings; partially offset by the prior year costs related to the disposition of AES Gilbert, including the recognition of an allowance on the sales-type lease receivable.

See Note 21—*Other Income and Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Gain (loss) on disposal and sale of business interests

Gain on disposal and sale of business interests was $134 million in 2023, primarily due to the gain on sale of shares of Fluence, our equity method investment, compared to a loss of $9 million in 2022.

See Note 8—*Investments in and Advances to Affiliates* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Goodwill impairment expense

Goodwill impairment expense was $12 million in 2023 due to a $12 million impairment at the TEG TEP reporting unit primarily driven by an increase in the discount rate due to increasing risk of non-renewal of operating permits required after March 31, 2024.

Goodwill impairment expense was $777 million in 2022 due to a $644 million impairment at AES Andes and a $133 million impairment at AES El Salvador. This was due to the Company seeing increases in inputs utilized to derive the discount rate applied in our goodwill impairment analysis, such as higher interest rates and country risk premiums in certain markets. These changes to the inputs of our discount rate negatively impacted our annual goodwill impairment test as of October 1, 2022.

See Note 9—*Goodwill and Other Intangible Assets* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Asset impairment expense

Asset impairment expense increased $304 million, or 40%, to $1.1 billion in 2023, compared to $763 million in 2022. This increase was primarily due to a $198 million impairment associated with PJM's approval to retire the Warrior Run coal-fired facility, a $186 million impairment at New York Wind related to a repowering project that will result in decommissioning the existing turbines and reducing their depreciable lives, a $167 million impairment at Mong Duong upon meeting the held-for-sale criteria, $151 million of impairments at AES Clean Energy Development primarily related to the write-off of project development intangibles for projects that were determined to be no longer viable, and a $137 million impairment associated with the commitment to accelerate the retirement of the Norgener coal-fired plant in Chile. This increase was partially offset by the $468 million impairment of Maritza's coal-fired plant in 2022 due to Bulgaria's commitment to cease electricity generation using coal as a fuel-source beyond 2038 and lower impairments at TEG and TEP in Mexico.

See Note 22—*Asset Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Foreign currency transaction losses

Foreign currency transaction gains (losses) in millions were as follows:

Years Ended December 31,	**2023**	**2022**
Argentina [1]	$ (312)	$ (88)
Chile	(40)	13
Corporate	(19)	—
Other	12	(2)
Total [2]	$ (359)	$ (77)

(1) Includes peso-denominated energy receivable indexed to the USD through the FONINVEMEM agreement which is considered a foreign currency derivative. See Note 7—*Financing Receivables* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

(2) Includes losses of $28 million and $20 million on foreign currency derivative contracts for the years ended December 31, 2023 and 2022, respectively.

The Company recognized net foreign currency transaction losses of $359 million in 2023, primarily driven by the depreciation of the Argentine peso, unrealized losses related to an intercompany loan denominated in the Colombian peso, and realized and unrealized foreign currency derivative losses in South America due to the depreciating Colombian peso.

The Company recognized net foreign currency transaction losses of $77 million in 2022, primarily driven by the depreciation of the Argentine peso, partially offset by realized foreign currency derivative gains in South America due to the depreciating Colombian peso.

Other non-operating expense

There was no other non-operating expense in 2023. Other non-operating expense was $175 million in 2022 due to the other-than-temporary impairment of the sPower equity method investment. The impairment analysis was triggered by the signing of a purchase and sale agreement which, at the time, implied an expected loss upon sale of the Company's indirect interest in a portfolio of sPower's operating assets ("OpCo B"). The transaction closed on February 28, 2023. sPower primarily holds operating assets where the tax credits associated with underlying projects have already been allocated to tax equity investors. The application of HLBV accounting increases the carrying value of these investments, as earnings are initially disproportionately allocated to the sponsor entity. Since sPower does not have any ongoing development or other value creation activities following the transfer of these activities to AES Clean Energy Development, the impairment adjusts the carrying value to the fair market value of the operating assets. See Note 25—*Acquisitions* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information regarding the formation of AES Clean Energy Development.

See Note 8—*Investments In and Advances to Affiliates* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Income tax benefit (expense)

Income tax expense was $261 million in 2023 compared to $265 million in 2022. The Company's effective tax rates were 251% and (157)% for the years ended December 31, 2023 and 2022, respectively.

The 2023 effective tax rate was impacted by noncontrolling interest in U.S. tax-equity partnerships and pretax impairments at certain Mexican subsidiaries and at the Mong Duong coal-fired plant in Vietnam. These impacts were partially offset by inflationary and foreign currency impacts at certain Argentine businesses, net of valuation allowances, as well as the recognition of U.S. investment tax credits for renewables projects placed in service this year. See Note 22—*Asset Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for details of the asset impairments.

The 2022 effective tax rate was impacted by the nondeductible goodwill impairments at AES Andes and AES El Salvador, as well as the asset impairment of the Maritza coal-fired plant. These impacts were partially offset by favorable LNG transactions at the Energy Infrastructure SBU and inflationary and foreign currency impacts at certain Argentine businesses recognized in 2022. See Note 9—*Goodwill and Other Intangible Assets* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for details of the goodwill impairments. See Note 22—*Asset Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for details of the asset impairments.

Our effective tax rate reflects the tax effect of significant operations outside the U.S., which are generally taxed at rates different than the U.S. statutory rate. Foreign earnings may be taxed at rates higher than the U.S. corporate rate of 21% and are also subject to current U.S. taxation under the GILTI rule. A future proportionate change in the composition of income before income taxes from foreign and domestic tax jurisdictions could impact our periodic effective tax rate. The Company also benefits from reduced tax rates in certain countries as a result of satisfying specific commitments regarding employment and capital investment. See Note 23—*Income Taxes* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional information regarding these reduced rates.

Net equity in losses of affiliates

Net equity in losses of affiliates decreased $39 million, or 55%, to $32 million in 2023, compared to $71 million in 2022. This decrease was primarily driven by an increase in earnings from Mesa La Paz, primarily due the termination of unrealized derivatives due to a contract amendment, and by a decrease in losses from Fluence, mainly attributable to improved margins on a new product line and reduced shipping constraints and transportation costs. This decrease in losses was partially offset by lower earnings from sPower, mainly due to lower earnings from renewables projects that came online.

See Note 8—*Investments In and Advances to Affiliates* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Net income (loss) attributable to noncontrolling interests and redeemable stock of subsidiaries

Net income attributable to noncontrolling interests and redeemable stock of subsidiaries decreased $472 million to a $431 million loss in 2023, compared to income of $41 million in 2022. This decrease was primarily due to:

- Increased costs associated with the growth of our business and higher allocation of losses to tax equity investors on projects placed in service at the Renewables SBU;
- Impairment at Mong Duong upon meeting the held-for-sale criteria in the current year;
- Prior year one-time revenue recognition driven by a reduction in a project's expected completion costs at the Energy Infrastructure SBU; and
- Lower earnings from the Utilities SBU due to unfavorable weather conditions.

These drivers were partially offset by:

- Higher earnings from the Renewables SBU due to favorable weather conditions; and
- Higher allocation of earnings at Southland Energy to noncontrolling interests.

Net income (loss) attributable to The AES Corporation

Net income attributable to The AES Corporation increased $795 million to $249 million in 2023, compared to a loss of $546 million in 2022. This increase was primarily due to:

- Lower goodwill impairments in the current year;
- Higher contributions from renewables projects placed in service in the current year;
- Prior year other-than-temporary impairment of our investment in sPower;
- Gain on sale of shares in Fluence in the current year;
- Increase in interest income due to higher average interest rates and short term investments at the Energy Infrastructure and Renewables SBUs;
- Higher earnings from the Utilities SBU due to the deferral of previously recognized purchased power costs and a prior year charge resulting from a regulatory settlement; and
- Lower losses from affiliates at the New Energy Technologies SBU.

These increases were partially offset by:

- Higher unrealized foreign currency losses at the Energy Infrastructure SBU;
- Higher long-lived asset impairments in the current year;
- Lower earnings from the Energy Infrastructure SBU due to prior year favorable LNG transactions, lower contract energy sales due to lower prices, lower thermal dispatch, and higher fixed costs; and
- Increase in interest expense due to higher interest rates and new debt issued at the Renewables and Energy Infrastructure SBUs, and a higher Parent Company weighted average interest rate.

SBU Performance Analysis

Segments

We are organized into four technology-based SBUs: **Renewables** (solar, wind, energy storage, and hydro generation facilities); **Utilities** (AES Indiana, AES Ohio, and AES El Salvador regulated utilities and their generation facilities); **Energy Infrastructure** (natural gas, LNG, coal, pet coke, diesel, and oil generation facilities, and our businesses in Chile); and **New Energy Technologies** (green hydrogen initiatives and investments in Fluence, Uplight, and 5B). Our businesses in Chile, which have a mix of generation sources, including renewables, are also included within the Energy Infrastructure SBU, as the generation from all sources is pooled to service our existing PPAs. In our 2022 Form 10-K, the management reporting structure and the Company's reportable segments were mainly organized by geographic regions. In March 2023, we announced internal management changes as a part of our ongoing strategy to align our business to meet our customers' needs and deliver on our major strategic objectives. The results of our operations are now reported along our four newly formed technology-based SBUs.

Non-GAAP Measures

EBITDA, Adjusted EBITDA, Adjusted EBITDA with Tax Attributes, Adjusted PTC, and Adjusted EPS are non-GAAP supplemental measures that are used by management and external users of our Consolidated Financial Statements such as investors, industry analysts, and lenders.

During the first quarter of 2023, management began assessing operational performance and making resource allocation decisions using Adjusted EBITDA. Therefore, the Company uses Adjusted EBITDA as its primary segment performance measure. EBITDA, Adjusted EBITDA, and Adjusted EBITDA with Tax Attributes are new non-GAAP supplemental measures reported beginning in the first quarter of 2023.

For the year ended December 31, 2023, the Company changed the definition of Adjusted EPS to remove the adjustment for *tax benefit or expense related to the enactment effects of 2017 U.S. tax law reform and related regulations and any subsequent period adjustments related to enactment effects, including the 2021 tax benefit on reversal of uncertain tax positions effectively settled upon the closure of the Company's U.S. tax return exam*. As this adjustment was specific to the impacts of tax law reform enacted in 2017, we believe removing this adjustment from our non-GAAP definition provides simplification and clarity for our investors. There were no such impacts in 2022 or 2023.

EBITDA, Adjusted EBITDA and Adjusted EBITDA with Tax Attributes

We define EBITDA as earnings before interest income and expense, taxes, depreciation, and amortization. We define Adjusted EBITDA as EBITDA adjusted for the impact of NCI and interest, taxes, depreciation, and amortization of our equity affiliates, adding back interest income recognized under service concession arrangements, and excluding gains or losses of both consolidated entities and entities accounted for under the equity method due to (a) unrealized gains or losses related to derivative transactions and equity securities; (b) unrealized foreign currency gains or losses; (c) gains, losses, benefits and costs associated with dispositions and acquisitions of business interests, including early plant closures, and gains and losses recognized at commencement of sales-type leases; (d) losses due to impairments; (e) gains, losses and costs due to the early retirement of debt; and (f) net gains at Angamos, one of our businesses in the Energy Infrastructure SBU, associated with the early contract terminations with Minera Escondida and Minera Spence.

In addition to the revenue and cost of sales reflected in Operating Margin, Adjusted EBITDA includes the other components of our Consolidated Statement of Operations, such as *general and administrative expenses* in Corporate and Other as well as business development costs, *other expense* and *other income, realized foreign currency transaction gains and losses,* and *net equity in earnings of affiliates*.

We further define Adjusted EBITDA with Tax Attributes as Adjusted EBITDA, adding back the pre-tax effect of Production Tax Credits ("PTCs"), Investment Tax Credits ("ITCs"), and depreciation tax deductions allocated to tax equity investors, as well as the tax benefit recorded from tax credits retained or transferred to third parties.

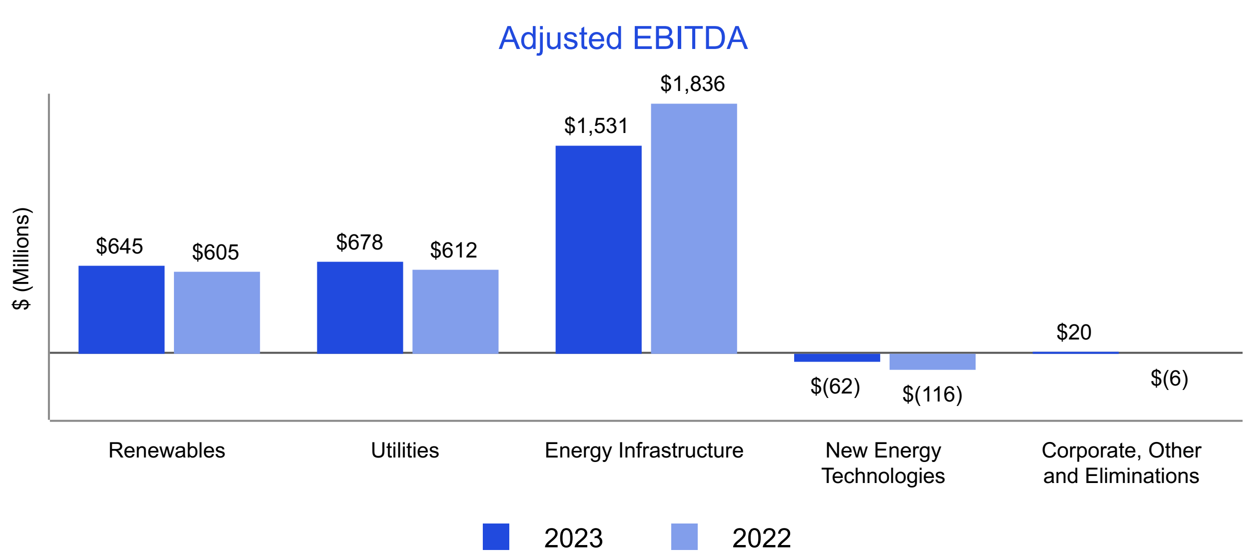
The GAAP measure most comparable to EBITDA, Adjusted EBITDA, and Adjusted EBITDA with Tax Attributes is *Net income*. We believe that EBITDA, Adjusted EBITDA, and Adjusted EBITDA with Tax Attributes better reflect the underlying business performance of the Company. Adjusted EBITDA is the most relevant measure considered in the Company's internal evaluation of the financial performance of its segments. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions or equity securities remeasurement, unrealized foreign currency gains or losses, losses due to impairments, strategic decisions to dispose of or acquire business interests or retire debt, the non-recurring nature of the impact of the early contract terminations at Angamos, and the variability of allocations of earnings to tax equity investors, which affect results in a given period or periods. In addition, each of these metrics represent the business performance of the Company before the application of statutory income tax rates and tax adjustments, including the effects of tax planning, corresponding to the various jurisdictions in which the Company operates. Given its large number of businesses and overall complexity, the Company concluded that Adjusted EBITDA is a more transparent measure than *Net income* that better assists investors in determining which businesses have the greatest impact on the Company's results.

EBITDA, Adjusted EBITDA, and Adjusted EBITDA with Tax Attributes should not be construed as alternatives to *Net income*, which is determined in accordance with GAAP.

	Years Ended December 31,	
Reconciliation of Adjusted EBITDA and Adjusted EBITDA with Tax Attributes (in millions)	**2023**	**2022**
Net loss	$ (182)	$ (505)
Income tax expense	261	265
Interest expense	1,319	1,117
Interest income	(551)	(389)
Depreciation and amortization	1,128	1,053
EBITDA	$ 1,975	$ 1,541
Less: Income from discontinued operations	(7)	—
Less: Adjustment for noncontrolling interests and redeemable stock of subsidiaries (1)	(552)	(704)
Less: Income tax expense (benefit), interest expense (income) and depreciation and amortization from equity affiliates	130	126
Interest income recognized under service concession arrangements	71	77
Unrealized derivative and equity securities losses	34	131
Unrealized foreign currency losses	301	42
Disposition/acquisition losses (gains)	(79)	40
Impairment losses	877	1,658
Loss on extinguishment of debt	62	20
Adjusted EBITDA (1)	$ 2,812	$ 2,931
Tax attributes	611	267
Adjusted EBITDA with Tax Attributes (2)	$ 3,423	$ 3,198

(1) The allocation of earnings and losses to tax equity investors from both consolidated entities and equity affiliates is removed from Adjusted EBITDA.

(2) Adjusted EBITDA with Tax Attributes includes the impact of the share of the ITCs, PTCs, and depreciation deductions allocated to tax equity investors under the HLBV accounting method and recognized as *Net loss (income) attributable to noncontrolling interests and redeemable stock of subsidiaries* on the Consolidated Statements of Operations. It also includes the tax benefit recorded from tax credits retained or transferred to third parties. The tax attributes are related to the Renewables and Utilities SBUs.



Adjusted PTC

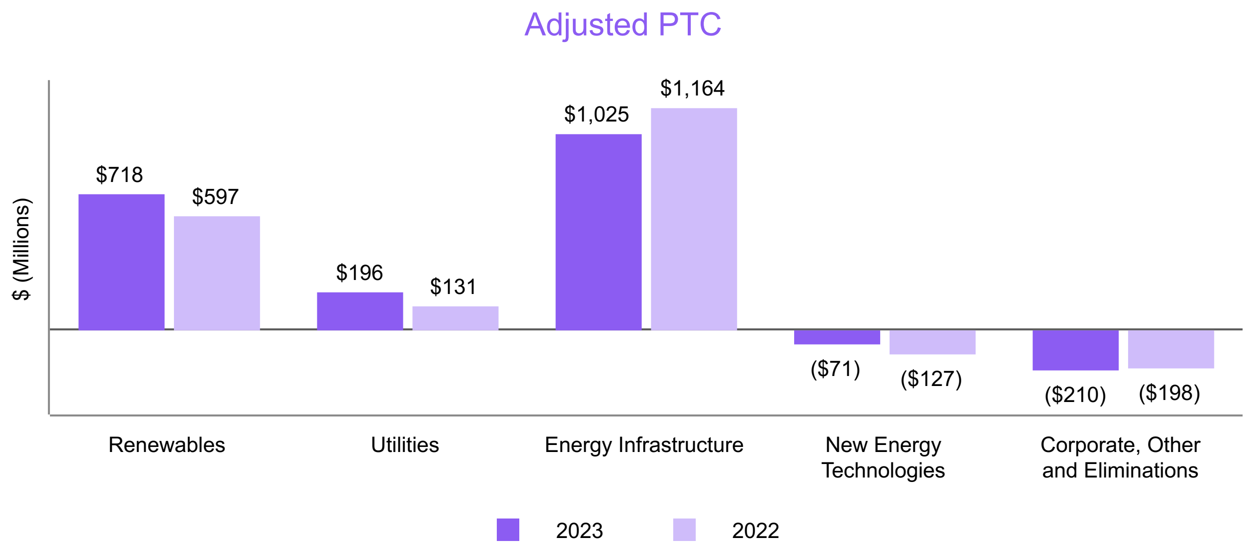
We define Adjusted PTC as pre-tax income from continuing operations attributable to The AES Corporation excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses related to derivative transactions and equity securities; (b) unrealized foreign currency gains or losses; (c) gains, losses, benefits and costs associated with dispositions and acquisitions of business interests, including early plant closures, and gains and losses recognized at commencement of sales-type leases; (d) losses due to impairments; (e) gains, losses and costs due to the early retirement of debt; and (f) net gains at Angamos, one of our businesses in the Energy Infrastructure SBU, associated with the early contract terminations with Minera Escondida and Minera Spence. Adjusted PTC also includes net equity in earnings of affiliates on an after-tax basis adjusted for the same gains or losses excluded from consolidated entities.

Adjusted PTC reflects the impact of NCI and excludes the items specified in the definition above. In addition to the revenue and cost of sales reflected in Operating Margin, Adjusted PTC includes the other components of our Consolidated Statement of Operations, such as *general and administrative expenses* in the Corporate segment, as well as business development costs, *interest expense* and *interest income, other expense* and *other income, realized foreign currency transaction gains and losses,* and *net equity in earnings of affiliates*.

The GAAP measure most comparable to Adjusted PTC is *income from continuing operations attributable to The AES Corporation*. We believe that Adjusted PTC better reflects the underlying business performance of the Company and is the most relevant measure considered in the Company's internal evaluation of the financial performance of its segments. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions or equity securities remeasurement, unrealized foreign currency gains or losses, losses due to impairments, strategic decisions to dispose of or acquire business interests or retire debt, and the non-recurring nature of the impact of the early contract terminations at Angamos, which affect results in a given period or periods. In addition, Adjusted PTC represents the business performance of the Company before the application of statutory income tax rates and tax adjustments, including the effects of tax planning, corresponding to the various jurisdictions in which the Company operates. Given its large number of businesses and complexity, the Company concluded that Adjusted PTC is a more transparent measure that better assists investors in determining which businesses have the greatest impact on the Company's results.

Adjusted PTC should not be construed as an alternative to *income from continuing operations attributable to The AES Corporation*, which is determined in accordance with GAAP.

Reconciliation of Adjusted PTC (in millions)	**Years Ended December 31, 2023**	**2022**
Income (loss) from continuing operations, net of tax, attributable to The AES Corporation	$ 242	$ (546)
Income tax expense attributable to The AES Corporation	206	210
Pre-tax contribution	448	(336)
Unrealized derivative and equity securities losses	41	128
Unrealized foreign currency losses	301	42
Disposition/acquisition losses (gains)	(79)	40
Impairment losses	877	1,658
Loss on extinguishment of debt	70	35
Total Adjusted PTC	$ 1,658	$ 1,567



Adjusted EPS

We define Adjusted EPS as diluted earnings per share from continuing operations excluding gains or losses of both consolidated entities and entities accounted for under the equity method due to (a) unrealized gains or losses related to derivative transactions and equity securities; (b) unrealized foreign currency gains or losses; (c) gains, losses, benefits and costs associated with dispositions and acquisitions of business interests, including early plant closures, the tax impact from the repatriation of sales proceeds, and gains and losses recognized at commencement of sales-type leases; (d) losses due to impairments; (e) gains, losses and costs due to the early retirement of debt; and (f) net gains at Angamos, one of our businesses in the Energy Infrastructure SBU, associated with the early contract terminations with Minera Escondida and Minera Spence.

The GAAP measure most comparable to Adjusted EPS is diluted earnings per share from continuing operations. We believe that Adjusted EPS better reflects the underlying business performance of the Company and is considered in the Company's internal evaluation of financial performance. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions or equity securities remeasurement, unrealized foreign currency gains or losses, losses due to impairments, strategic decisions to dispose of or acquire business interests or retire debt, and the non-recurring nature of the impact of the early contract terminations at Angamos, which affect results in a given period or periods. Adjusted EPS should not be construed as an alternative to diluted earnings per share from continuing operations, which is determined in accordance with GAAP.

The Company reported a loss from continuing operations of $0.82 for the year ended December 31, 2022. For purposes of measuring diluted loss per share under GAAP, common stock equivalents were excluded from weighted average shares as their inclusion would be anti-dilutive. However, for purposes of computing Adjusted EPS, the Company has included the impact of dilutive common stock equivalents. The table below reconciles the weighted average shares used in GAAP diluted loss per share to the weighted average shares used in calculating the non-GAAP measure of Adjusted EPS.

Reconciliation of Denominator Used for Adjusted EPS	**Year Ended December 31, 2022**		
(in millions, except per share data)	**Loss**	**Shares**	**$ per Share**
GAAP DILUTED LOSS PER SHARE			
Loss from continuing operations attributable to The AES Corporation common stockholders	$ (546)	668	$ (0.82)
EFFECT OF DILUTIVE SECURITIES			
Stock options	—	1	—
Restricted stock units	—	2	—
Equity units	—	40	0.05
NON-GAAP DILUTED LOSS PER SHARE	$ (546)	711	$ (0.77)

Reconciliation of Adjusted EPS	Years Ended December 31, 2023		Years Ended December 31, 2022	
Diluted earnings (loss) per share from continuing operations	$ 0.34		$ (0.77)	
Unrealized derivative and equity securities losses	0.06	(1)	0.18	(2)
Unrealized foreign currency losses	0.42	(3)	0.07	(4)
Disposition/acquisition losses (gains)	(0.11)	(5)	0.06	(6)
Impairment losses	1.23	(7)	2.33	(8)
Loss on extinguishment of debt	0.10	(9)	0.05	(10)
Less: Net income tax benefit	(0.28)	(11)	(0.25)	(12)
Adjusted EPS	$ 1.76		$ 1.67	

(1) Amount primarily relates to unrealized derivative losses due to the termination of a PPA of $72 million, or $0.10 per share and net unrealized derivative losses at AES Clean Energy of $20 million, or $0.03 per share, offset by net unrealized derivative gains at the Energy Infrastructure SBU of $46 million, or $0.06 per share.

(2) Amount primarily relates to unrealized losses on power swaps at Southland Energy of $109 million, or $0.15 per share.

(3) Amount primarily relates to unrealized foreign currency losses in Argentina of $262 million, or $0.37 per share, mainly associated with the devaluation of long-term receivables denominated in Argentine pesos, and unrealized foreign currency losses at AES Andes of $25 million, or $0.03 per share.

(4) Amount primarily relates to unrealized foreign currency losses in Argentina of $39 million, or $0.05 per share, mainly associated with the devaluation of long-term receivables denominated in Argentine pesos.

(5) Amount primarily relates to the gain on sale of Fluence shares of $136 million, or $0.19 per share, partially offset by costs due to early plant closure at the Ventanas 2 and Norgener coal-fired plants in Chile of $37 million, or $0.05 per share and at Warrior Run of $6 million, or $0.01 per share, and day-one losses recognized at commencement of sales-type leases at AES Renewable Holdings of $20 million, or $0.03 per share.

(6) Amount primarily relates to costs on disposition of AES Gilbert, including the recognition of an allowance on the sales-type lease receivable, of $13 million, or $0.02 per share, and a day-one loss recognized at commencement of a sales-type lease at AES Waikoloa Solar of $5 million, or $0.01 per share.

(7) Amount primarily relates to asset impairments at Warrior Run of $198 million, or $0.28 per share, at New York Wind of $139 million, or $0.20 per share, the Norgener coal-fired plant in Chile of $136 million, or $0.19 per share, at TEG and TEP of $76 million and $58 million, respectively, or $0.19 per share, AES Clean Energy development projects of $114 million, or $0.16 per share, at Mong Duong of $88 million, or $0.12 per share, at Jordan of $21 million, or $0.03 per share, and at the GAF Projects at AES Renewable Holdings of $18 million, or $0.03 per share, and a goodwill impairment at the TEG TEP reporting unit of $12 million, or $0.02 per share.

(8) Amount primarily relates to goodwill impairments at AES Andes of $644 million, or $0.91 per share, and at AES El Salvador of $133 million, or $0.19 per share, other-than-temporary impairment at sPower of $175 million, or $0.25, as well as long-lived asset impairments at Maritza of $468 million, or $0.66 per share, at TEG TEP of $191 million, or $0.27 per share, and in Jordan of $28 million, or $0.04 per share.

(9) Amount primarily relates to losses incurred at AES Andes due to early retirement of debt of $46 million, or $0.07 per share, and loss on early retirement of debt at AES Hispanola Holdings BV of $10 million, or $0.01 per share.

(10) Amount primarily relates to losses on early retirement of debt due to refinancing at AES Renewable Holdings of $12 million, or $0.02 per share, at AES Clean Energy of $5 million, or $0.01 per share, at Mong Duong of $4 million, or $0.01 per share, and at TEG TEP of $4 million, or $0.01 per share.

(11) Amount primarily relates to income tax benefits associated with the asset impairments at Warrior Run of $46 million, or $0.06 per share, at the Norgener coal-fired plant in Chile of $37 million, or $0.05 per share, at New York Wind of $32 million, or $0.05 per share, at TEG and TEP of $27 million, or $0.04 per share, and at AES Clean Energy development projects of $26 million, or $0.04 per share; income tax benefits associated with the recognition of unrealized losses due to the termination of a PPA of $17 million, or $0.02 per share; and income tax benefits associated with losses incurred at AES Andes due to early retirement of debt of $13 million, or $0.02 per share; partially offset by income tax expense associated with the gain on sale of Fluence shares of $31 million, or $0.04 per share.

(12) Amount primarily relates to income tax benefits associated with the impairment at Maritza of $48 million, or $0.07 per share, income tax benefits associated with the other-than-temporary impairment at sPower of $39 million, or $0.06 per share, income tax benefits associated with the impairment at TEG TEP of $34 million, or $0.05 per share, and income tax benefits associated with unrealized losses on power swaps at Southland Energy of $24 million, or $0.03 per share.

Renewables SBU

The following table summarizes Operating Margin, Adjusted EBITDA, and Adjusted EBITDA with Tax Attributes (in millions) for the periods indicated:

For the Years Ended December 31,	2023	2022	$ Change	% Change
Operating Margin	$ 492	$ 528	$ (36)	-7%
Adjusted EBITDA (1)	645	605	40	7%
Adjusted EBITDA with Tax Attributes (1)	1,238	872	366	42%

(1) A non-GAAP financial measure. See *SBU Performance Analysis—Non-GAAP Measures* for definition and Item 1.—*Business* for the respective ownership interest for key businesses.

Operating Margin decreased $36 million driven primarily by higher fixed costs due to an accelerated growth plan and unrealized derivative losses. This decrease was partially offset by better hydrology, new businesses operating in our portfolio, and higher wind availability, resulting in higher renewable energy generation.

Adjusted EBITDA increased $40 million primarily due to the drivers mentioned above, adjusted for NCI, unrealized derivatives, and depreciation expense.

Adjusted EBITDA with Tax Attributes increased $366 million, primarily due to higher realized tax attributes driven by more projects being placed in service, as well as impact from the increase in Adjusted EBITDA. For the year ended December 31, 2023 and 2022, we realized $593 million and $267 million, respectively, from tax attributes earned by AES Clean Energy businesses.

Utilities SBU

The following table summarizes Operating Margin, Adjusted EBITDA, Adjusted EBITDA with Tax Attributes, and Adjusted PTC (in millions) for the periods indicated:

For the Years Ended December 31,	2023	2022	$ Change	% Change
Operating Margin	$ 433	$ 379	$ 54	14 %
Adjusted EBITDA [1]	678	612	66	11 %
Adjusted EBITDA with Tax Attributes [1]	696	612	84	14 %
Adjusted PTC [1] [2]	196	131	65	50 %

(1) A non-GAAP financial measure. See *SBU Performance Analysis—Non-GAAP Measures* for definition and Item 1.—*Business* for the respective ownership interest for key businesses.

(2) Adjusted PTC remains a key metric used by management for analyzing our businesses in the utilities industry.

Operating Margin increased $54 million mainly driven by the deferral of purchased power costs in the current year, which were recognized in the prior year, associated with the ESP 4 approval, an increase in transmission and TDSIC rider revenues, higher demand due to extreme heat in El Salvador, and a regulatory settlement in the prior year, partially offset by the impact of milder weather in Indiana and Ohio, higher fixed costs, and increased depreciation expense.

Adjusted EBITDA increased $66 million primarily due to the drivers above, adjusted for NCI and depreciation expense, partially offset by an increase in defined benefit plan costs.

Adjusted EBITDA with Tax Attributes increased $84 million due to the drivers above, as well as $18 million of realized tax attributes related to the Hardy Hills solar project in the current year.

Adjusted PTC increased $65 million primarily due to the drivers above, partially offset by higher depreciation expense.

Energy Infrastructure SBU

The following table summarizes Operating Margin and Adjusted EBITDA (in millions) for the periods indicated:

For the Years Ended December 31,	2023	2022	$ Change	% Change
Operating Margin	$ 1,418	$ 1,535	$ (117)	-8%
Adjusted EBITDA [1]	1,531	1,836	(305)	-17%

(1) A non-GAAP financial measure. See *SBU Performance Analysis—Non-GAAP Measures* for definition and Item 1.—*Business* for the respective ownership interest for key businesses.

Operating Margin decreased $117 million, driven primarily by lower LNG transactions, lower contract energy sales due to lower prices, lower dispatch driven by lower demand, higher fixed costs, and a prior year one-time revenue recognition driven by a reduction in a project's expected completion costs.

The decrease in Operating Margin is partially offset by unrealized gains resulting mainly from derivatives as part of our commercial hedging strategy, higher revenues due to a PPA termination agreement, lower outages, and lower depreciation expense due to impairments recognized in the current and prior year.

Adjusted EBITDA decreased $305 million, primarily due to the drivers above adjusted for NCI, unrealized derivative gains, and depreciation, as well as higher realized foreign currency losses and lower insurance recovery.

New Energy Technologies SBU

The following table summarizes Operating Margin and Adjusted EBITDA (in millions) for the periods indicated:

For the Years Ended December 31,	2023	2022	$ Change	% Change
Operating Margin	$ (9)	$ (7)	$ (2)	-29%
Adjusted EBITDA [1]	(62)	(116)	54	47%

[1] A non-GAAP financial measure. See *SBU Performance Analysis—Non-GAAP Measures* for definition and Item 1.—*Business* for the respective ownership interest for key businesses.

Operating Margin decreased $2 million, with no material drivers.

Adjusted EBITDA increased $54 million, primarily driven by lower losses at Fluence due to improved margins on a new product line, the settlement of contractual claims with a battery module vendor, and incremental shipping and transportation costs incurred in the prior year as a result of COVID-19. These increases were partly offset by higher costs for research and development, sales and marketing, and general and administrative expenses.

Key Trends and Uncertainties

During 2024 and beyond, we expect to face the following challenges at certain of our businesses. Management expects that improved operating performance at certain businesses, growth from new businesses, and global cost reduction initiatives may lessen or offset their impact. If these favorable effects do not occur, or if the challenges described below and elsewhere in this section impact us more significantly than we currently anticipate, or if volatile foreign currencies and commodities move more unfavorably, then these adverse factors (or other adverse factors unknown to us) may have a material impact on our operating margin, net income attributable to The AES Corporation and cash flows. We continue to monitor our operations and address challenges as they arise. For the risk factors related to our business, see Item 1.—*Business* and Item 1A.—*Risk Factors* of this Form 10-K.

Operational

Trade Restrictions and Supply Chain — On March 29, 2022, the U.S. Department of Commerce ("Commerce") announced the initiation of an investigation into whether imports into the U.S. of solar cells and panels imported from Cambodia, Malaysia, Thailand, and Vietnam ("Southeast Asia") are circumventing antidumping and countervailing duty ("AD/CVD") orders on solar cells and panels from China. This investigation resulted in significant systemic disruptions to the import of solar cells and panels from Southeast Asia. On June 6, 2022, President Biden issued a Proclamation waiving any circumvention duties on imported solar cells and panels from Southeast Asia that result from this investigation for a 24-month period ending June 6, 2024. Suppliers resumed importing cells and panels from Southeast Asia into the U.S. pursuant to a Commerce certification regime implementing the Proclamation.

On December 2, 2022, Commerce issued country-wide affirmative preliminary determinations that circumvention had occurred in each of the four Southeast Asian countries. Commerce also evaluated numerous individual companies and issued preliminary determinations that circumvention had occurred with respect to many but not all of these companies. Additionally, Commerce issued a preliminary determination that circumvention would not be deemed to occur for any solar cells and panels imported from the four countries if the wafers were manufactured outside of China or if no more than two out of six specifically identified components were produced in China. On August 18, 2023, Commerce issued its final determinations on the matter and affirmed its preliminary findings in most respects. Additionally, Commerce found that three of the specific companies it investigated were not circumventing.

On December 29, 2023, Auxin Solar and Concept Clean Energy filed a lawsuit with the U.S. Court of International Trade, challenging certain aspects of the final rule promulgated by Commerce to implement the Proclamation. The lawsuit specifically challenges Commerce's decisions not to suspend the final disposition of certain entries of imported solar cells and panels from Southeast Asia made prior to June 6, 2024, and not to collect AD/CVD deposits with respect to those entries. The Department of Justice has responded by filing a motion to dismiss the lawsuit.

Additionally, the Uyghur Forced Labor Prevention Act ("UFLPA") seeks to block the import of products made with forced labor in certain areas of China and may lead to certain suppliers being blocked from importing solar cells and panels to the U.S. While this has impacted the U.S. market, AES has managed this issue without significant impact to our projects. Further disruptions may impact our suppliers' ability or willingness to meet their contractual agreements or to continue to supply cells or panels into the U.S. market on terms that we deem satisfactory.

The impact of any additional adverse Commerce determinations or other tariff disputes or litigation, the impact of the UFLPA, potential future disruptions to the solar panel supply chain and their effect on AES' U.S. solar project development and construction activities remain uncertain. AES will continue to monitor developments and take prudent steps towards maintaining a robust supply chain for our renewables projects.

We have contracted and secured our expected requirements for solar panels for U.S. projects targeted to achieve commercial operations in 2024.

Operational Sensitivity to Dry Hydrological Conditions — Our hydroelectric generation facilities are sensitive to changes in the weather, particularly the level of water inflows into generation facilities. In the past, dry hydrological conditions in Panama, Brazil, Colombia and Chile have presented challenges for our businesses in these markets. Low rainfall and water inflows have caused reservoir levels to be below historical levels, reduced generation output, and increased prices for electricity. If our hydroelectric generation facilities cannot generate sufficient energy to meet contractual arrangements, we may need to purchase energy to fulfill our obligations, which could have a material adverse impact on our results of operations. As a mitigation measure, AES has invested in thermal, wind, and solar generation assets, which have a complementary profile to hydroelectric plants. These plants are expected to have a higher generation in low hydrology scenarios, which allows them to generate additional revenues from the spot that offset purchases on the hydroelectric side.

According to the National Oceanic and Atmospheric Administration ("NOAA"), El Niño conditions are observed and forecasted through the beginning of Q2 of 2024. Hydrological conditions thereafter are uncertain, but indications suggest either a return to normalized patterns or an emergence of La Niña for the remainder of 2024. In Panama, consistent with expected El Niño impacts, local hydrological forecasts indicate below historical average inflows persisting into Q2 of 2024, which could impact our results of operations. AES reduced its total generation exposure in Panama to dry hydrological conditions through investments in such complementary assets as the Colon LNG power facility, which commenced operations in 2018, the Penonome Wind Farm, and solar projects, providing a stable and independent diversified energy supply during periods of drought or when hydroelectric generation is limited. In Panama, the La Niña phenomenon in contrast to El Niño typically means wetter conditions than average, although local system impacts may vary due to other factors. Higher hydrology may result in energy surpluses after covering the contracted hydro positions, available to be sold in the spot market after fulfilling contract obligations.

In Brazil, El Niño generally means more rainfall in the South and higher temperatures in the central region of the country, as seen in the last quarter of 2023, while La Niña results in more rainfall in the North, drier conditions in the South and milder temperatures in the central region, which could result in lower demand. Current system reservoir levels are high which supports continued lower spot prices through 2024 mitigating hydrological risk – lower prices limit external thermal generation which, if dispatched, could impact demand for the AES hydro generation. In Colombia, El Niño is characterized by drought and may result in higher spot prices. Lower overall AES Chivor hydrology may result in increased spot price energy exposure to cover contracted positions. The basin where AES Chivor is located typically experiences wet conditions from June through September in contrast with the broader system, which can result in additional energy available to sell in the spot market after fulfilling contract obligations as experienced earlier in 2023. La Niña in Colombia is characterized by more rainfall possibly leading to a decrease in spot prices. However, during La Niña impacts vary and the basin where Chivor is located may experience drier conditions than the system, notably between June and September. In Chile, the primary driver for AES' hydro assets is snowpack volumes. Lower snowpack, together with reduced rainfall in the system, could increase both spot prices and energy purchase volumes required to meet contracted positions.

The exact behavior pattern and strength of El Niño and the potential evolution towards La Niña cannot be definitively known at this time and therefore the impacts could vary from those described above, and may include impacts to our businesses beyond hydrology, including with respect to power generation from other renewable sources of energy and demand. Even if rainfall and water inflows return to or exceed historical averages, in some cases high market prices and low generation could persist until reservoir levels are fully recovered. Further, investments made in thermal, wind, and solar power generation may benefit from uncontracted spot sales at higher market prices. Our thermal assets in Panama may alternatively be impacted by low dispatch due to low market prices in the event of a La Niña. Impacts may be material to our results of operations.

Macroeconomic and Political

The macroeconomic and political environments in some countries where our subsidiaries conduct business have changed during 2023. This could result in significant impacts to tax laws and environmental and energy policies. Additionally, we operate in multiple countries and as such are subject to volatility in exchange rates at the subsidiary level. See Item 7A.—*Quantitative and Qualitative Disclosures About Market Risk* for further information.

Argentina — The recent election of President Javier Milei on December 10, 2023, marks a pivotal moment in Argentina's economic landscape. The entering administration issued Decree No. 55/23, signaling a commitment to total economic deregulation. This decree declares a state of emergency in the power sector, tariff revisions for electric power and natural gas transport and distribution, and a broader proposal for sector-wide reform.

President Milei also proposed a new bill, currently under review by Congress, that seeks to overhaul the energy regulatory framework. Emphasizing deregulation, the bill opens avenues for privatization of state-owned energy companies. These proposed changes may have a profound impact on the sector, influencing our operations and financial results. It is not yet possible to predict the impact of these regulations in our consolidated results of operations, cash flows, and financial condition.

Inflation Reduction Act and U.S. Renewable Energy Tax Credits — The Inflation Reduction Act (the "IRA") was signed into law in the United States. The IRA includes provisions that are expected to benefit the U.S. clean energy industry, including increases, extensions, direct transfers and/or new tax credits for onshore and offshore wind, solar, storage and hydrogen projects. We expect that the extension of the current solar investment tax credits ("ITCs"), as well as higher credits available for projects that satisfy wage and apprenticeship requirements, will increase demand for our renewables products.

Our U.S. renewables business has a 51 GW pipeline that we intend to utilize to continue to grow our business, and these changes in tax policy are supportive of this strategy. We account for U.S. renewables projects according to U.S. GAAP, which, when partnering with tax-equity investors to monetize tax benefits, utilizes the HLBV method. This method recognizes the tax-credit value that is transferred to tax equity investors at the time of its creation, which for projects utilizing the investment tax credit begins in the quarter the project is placed in service. For projects utilizing the production tax credit, this value is recognized over 10 years as the facility produces energy.

The IRA also allows us to directly transfer investment tax credits to unrelated tax credit buyers. We account for the transfer proceeds as tax benefit throughout the year the renewables project is placed in service.

In 2023, we realized $611 million of earnings from Tax Attributes, comprised of $593 million from the Renewables SBU and $18 million from the Utilities SBU. In 2024, we expect an increase in Tax Attributes earned by our U.S. renewables business in line with the growth in that business. Based on construction schedules, a significant portion of these earnings will be realized in the fourth quarter.

The implementation of the IRA requires substantial guidance from the U.S. Department of Treasury and other government agencies. While some of that guidance remains pending, there will be uncertainty with respect to the implementation of certain provisions of the IRA.

Global Tax — The macroeconomic and political environments in the U.S. and in some countries where our subsidiaries conduct business have changed during 2022 and 2023. This could result in significant impacts to future tax law. In the U.S., the IRA includes a 15% corporate alternative minimum tax based on adjusted financial statement income. Additional guidance is expected to be issued in 2024.

In the fourth quarter of 2022, the European Commission adopted an amended Directive on Pillar 2 establishing a global minimum tax at a 15% rate. The adoption requires EU Member States to transpose the Directive into their respective national laws by December 31, 2023 for the rules to come into effect as of January 1, 2024. During 2023, the Netherlands, Bulgaria and Vietnam adopted legislation to implement Pillar 2 effective as of January 1, 2024. We will continue to monitor the issuance of draft legislation in other non-EU countries where the Company operates that are considering Pillar 2 amendments. The impact to the Company remains unknown but may be material.

Inflation — In the markets in which we operate, there have been higher rates of inflation recently. While most of our contracts in our international businesses are indexed to inflation, in general, our U.S.-based generation contracts are not indexed to inflation. If inflation continues to increase in our markets, it may increase our expenses that we may not be able to pass through to customers. It may also increase the costs of some of our development projects that could negatively impact their competitiveness. Our utility businesses do allow for recovering of operations and maintenance costs through the regulatory process, which may have timing impacts on recovery.

Interest Rates — In the U.S. and other markets in which we operate, there has been a rise in interest rates during 2021 through 2023, and interest rates are expected to remain volatile in the near term. As discussed in Item 7A.—*Quantitative and Qualitative Disclosures about Market Risk,* although most of our existing corporate and subsidiary debt is at fixed rates, an increase in interest rates can have several impacts on our business. For any existing debt under floating rate structures and any future debt refinancings, rising interest rates will increase future financing costs. In most cases in which we have floating rate debt, our revenues serving this debt are indexed to inflation which helps mitigate the impact of rising rates. For future debt refinancings, AES actively manages a hedging program to reduce uncertainty and exposure to future interest rates. For new business, higher interest rates increase the financing costs for new projects under development and which have not yet secured financing.

AES typically seeks to incorporate expected financing costs into our new PPA pricing such that we maintain our target investment returns, but higher financing costs may negatively impact our returns or the competitiveness of some of our development projects. Additionally, we typically seek to enter into interest rate hedges shortly after signing PPAs to mitigate the risk of rising interest rates prior to securing long-term financing.

Puerto Rico — Our subsidiaries in Puerto Rico have long-term PPAs with state-owned PREPA, which has been facing economic challenges that could result in a material adverse effect on our business in Puerto Rico. Despite the Title III protection, PREPA has been making substantially all of its payments to the generators in line with historical payment patterns.

The Puerto Rico Oversight, Management, and Economic Stability Act (“PROMESA”) was enacted to create a structure for exercising federal oversight over the fiscal affairs of U.S. territories and created procedures for adjusting debt accumulated by the Puerto Rico government and, potentially, other territories (“Title III”). PROMESA also expedites the approval of key energy projects and other critical projects in Puerto Rico.

PROMESA allowed for the establishment of an Oversight Board with broad powers of budgetary and financial control over Puerto Rico. The Oversight Board filed for bankruptcy on behalf of PREPA under Title III in July 2017. As a result of the bankruptcy filing, AES Puerto Rico and AES Ilumina’s non-recourse debt of $143 million and $25 million, respectively, continue to be in technical default and are classified as current as of December 31, 2023. The non-recourse debt at AES Puerto Rico is also in payment default.

On April 12, 2022, a mediation team was appointed to prepare the plan to resolve the PREPA Title III case and related proceedings. A disclosure statement hearing was held on April 28, 2023. The mediation was extended through August 4, 2023. On November 14, 2023, the Judge presiding over the case approved the supplemental disclosure statement for PREPA’s Fourth Modified Third Amended Title III Plan of Adjustment. The confirmation trial is still scheduled to begin March 4, 2024.

Earlier this year, AES Puerto Rico took certain measures to address identified liquidity challenges. On July 6, 2023, PREPA agreed to the release of funds in the escrow account guaranteeing AES Puerto Rico’s obligations under the Power Purchase and Operating Agreement (“PPOA”) in order to provide additional liquidity for the business. AES Puerto Rico continues to work with PREPA and its noteholders on these liquidity challenges. During Q4 2023, a restructuring support agreement was executed by AES Puerto Rico and its noteholders and a PPOA amendment was approved by PREPA. These agreements require Puerto Rico Energy Bureau ("PREB") approval to become effective. On February 2, 2024 a resolution was issued by PREB approving the PPOA amendment subject to the incorporation of certain additional terms and conditions. The Company expects the PPOA amendment and restructuring support agreement to become effective during the first quarter of 2024.

Despite these challenges and considering the information available as of the filing date, management believes the carrying amount of our long-lived assets at AES Puerto Rico of $76 million is recoverable as of December 31, 2023.

Mexico Migration and Wheeling Tariffs — The interconnection agreements for TEP and TEG under the self-supply energy regime in Mexico expire in March and April 2024, respectively. Consequently, TEG and TEP are required to migrate into the new energy regime established by the Electricity Industry Law of 2021 (“LIE”) and to execute new interconnection agreements prior to the expiration of the current interconnection agreements. In February and September 2022, respectively, TEG and TEP made formal requests to the Mexican Comision Reguladora de Energia (“CRE”) to update the projects’ permits and allow them to migrate into the LIE (“Migration Requests”).

In discussions with TEG and TEP, CRE has stated that it will not allow migration into the LIE unless the projects withdraw their respective legal challenges to certain laws, including RES/894/2020 ("Resolution 894"), which attempts to increase the wheeling tariffs paid by TEG and TEP to CFE. The increase is currently estimated to be over $90 million for the relevant period (July 2020 through March 2024). TEG and TEP have informed CRE that the agency is not entitled to reject the Migration Requests because of the legal challenges. In February 2024, the Collegiate Court ruled in favor of TEG and TEP on their challenge to Resolution 894. Nevertheless, later in February 2024, CRE denied TEG's Migration Request. TEG has formally requested that CRE issue a new permit. If CRE does not issue a new permit and if TEG cannot enter into a new interconnection agreement, TEG will not be allowed to operate after its current interconnection agreement expires. CRE is expected to determine TEP's Migration Request in the near future, but we cannot predict the outcome of that determination.

TEG and TEP will take all necessary regulatory and legal steps to protect their interests. Furthermore, if TEG and TEP are ever required to pay increased wheeling tariffs, TEG and TEP will seek to enforce their respective contractual rights to pass-through the increases to their respective offtakers. However, there are no assurances that TEG and TEP will be successful in these efforts. The inability to migrate into the LIE and/or the inability to pass-through wheeling tariff increases could have a material adverse impact on our results of operations.

Decarbonization Initiatives

Our strategy involves shifting towards clean energy platforms, including renewable energy, energy storage, LNG, and modernized grids. It is designed to position us for continued growth while reducing our carbon intensity and in support of our mission of accelerating the future of energy, together. We have made significant progress on our exit of coal generation, and we intend to exit the substantial majority of our remaining coal facilities by year-end 2025 and intend to exit all of the coal facilities by year-end 2027, subject to necessary approvals.

In addition, initiatives have been announced by regulators, including in Chile, Puerto Rico, and Bulgaria, and offtakers in recent years, with the intention of reducing GHG emissions generated by the energy industry. In parallel, the shift towards renewables has caused certain customers to migrate to other low-carbon energy solutions and this trend may continue.

Although we cannot currently estimate the financial impact of these decarbonization initiatives, new legislative or regulatory programs further restricting carbon emissions or other initiatives to voluntarily exit coal generation could require material capital expenditures, resulting in a reduction of the estimated useful life of certain coal facilities, or have other material adverse effects on our financial results.

For further information about the risks associated with decarbonization initiatives, see Item 1A.—*Risk Factors —Concerns about GHG emissions and the potential risks associated with climate change have led to increased regulation and other actions that could impact our businesses* included in this Form 10-K.

Regulatory

AES Maritza PPA Review — DG Comp is conducting a preliminary review of whether AES Maritza's PPA with NEK is compliant with the European Union's State Aid rules. No formal investigation has been launched by DG Comp to date. AES Maritza has previously engaged in discussions with the DG Comp case team and the Government of Bulgaria ("GoB") to attempt to reach a negotiated resolution of the DG Comp's review ("PPA Discussions"). There are no active PPA Discussions at present but those discussions could resume at any time. The PPA continues to remain in place. However, there can be no assurance that, in the context of DG Comp's preliminary review or any future PPA Discussions, the other parties will not seek a prompt termination of the PPA.

We do not believe termination of the PPA is justified. Nevertheless, the PPA Discussions involved a range of potential outcomes, including but not limited to the termination of the PPA and payment of some level of compensation to AES Maritza. Any negotiated resolution would be subject to mutually acceptable terms, lender consent, and DG Comp approval. At this time, we cannot predict whether and when the PPA Discussions might resume or the outcome of any such discussions. Nor can we predict how DG Comp might resolve its review if the PPA Discussions do not resume or if any such discussions fail to result in an agreement concerning the agency's review. AES Maritza believes that its PPA is legal and in compliance with all applicable laws, and it will take all actions necessary to protect its interests, whether through negotiated agreement or otherwise. However, there can be no assurance that this matter will be resolved favorably; if it is not, there could be a material adverse effect on the Company's financial condition, results of operation, and cash flows. As of December 31, 2023, the carrying value of our long-lived assets at Maritza is $345 million.

Foreign Exchange Rates

We operate in multiple countries and as such are subject to volatility in exchange rates at varying degrees at the subsidiary level and between our functional currency, the USD, and currencies of the countries in which we operate.

The overall economic climate in Argentina has deteriorated, resulting in volatility and increased the risk that a further significant devaluation of the Argentine peso against the USD, similar to the devaluations experienced by the country in 2018, 2019, and 2023, may occur. A continued trend of peso devaluation could result in increased inflation, a deterioration of the country's risk profile, and other adverse macroeconomic effects that could significantly impact our results of operations. For additional information, refer to Item 7A.—*Quantitative and Qualitative Disclosures About Market Risk*.

Impairments

Long-lived Assets and Current Assets Held-for-Sale — During the year ended December 31, 2023, the Company recognized asset impairment expense of $1.1 billion. See Note 8—*Investments and Advances to Affiliates* and Note 22—*Asset Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information. After recognizing these impairment expenses, the carrying value of our investments in long-lived assets and current assets held-for-sale that were assessed for impairment following a triggering event in 2023 totaled $1.3 billion at December 31, 2023.

Events or changes in circumstances that may necessitate recoverability tests and potential impairments of long-lived assets may include, but are not limited to, adverse changes in the regulatory environment, unfavorable changes in power prices or fuel costs, increased competition due to additional capacity in the grid, technological advancements, declining trends in demand, evolving industry expectations to transition away from fossil fuel sources for generation, or an expectation it is more likely than not the asset will be disposed of before the end of its estimated useful life.

Goodwill — An increase in the discount rate at TEG TEP has negatively impacted our annual goodwill impairment test as of October 1, 2022, and thus, an impairment of goodwill of $12 million has been recognized as of December 31, 2023, reducing the goodwill balance of TEG TEP to zero. See Note 9—*Goodwill and Other Intangibles Assets* included in Item 8.—*Financial Statements and Supplementary Data* for further information.

The Company had no other reporting units considered to be "at risk," as the fair value of all other reporting units exceeded their carrying amounts by more than 10%. Should the fair value of any of the Company's reporting units fall below its carrying amount as a result of these inputs or other changes such as reduced operating performance, market declines, changes in the discount rate, regulatory changes, or other adverse conditions, goodwill impairment charges may be necessary in future periods.

Capital Resources and Liquidity

Overview

As of December 31, 2023, the Company had unrestricted cash and cash equivalents of $1.4 billion, of which $33 million was held at the Parent Company and qualified holding companies. The Company had $395 million in short-term investments, held primarily at subsidiaries, and restricted cash and debt service reserves of $564 million. The Company also had non-recourse and recourse aggregate principal amounts of debt outstanding of $22.1 billion and $4.5 billion, respectively. Of the $3.9 billion of our current non-recourse debt, $3.6 billion was presented as such because it is due in the next twelve months and $325 million relates to debt considered in default. Defaults at AES Puerto Rico are covenant and payment defaults. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Macroeconomic and Political—Puerto Rico* for additional detail. All other defaults are not payment defaults but are instead technical defaults triggered by failure to comply with covenants or other requirements contained in the non-recourse debt documents. As of December 31, 2023, the Company also had $974 million outstanding related to supplier financing arrangements.

We expect current maturities of non-recourse debt, recourse debt, and amounts due under supplier financing arrangements to be repaid from net cash provided by operating activities of the subsidiary to which the liability relates, through opportunistic refinancing activity, or some combination thereof. We have $200 million in recourse debt which matures within the next twelve months, as well as amounts due under supplier financing arrangements, of which $814 million has a Parent Company guarantee. From time to time, we may elect to repurchase our outstanding debt through cash purchases, privately negotiated transactions or otherwise when management believes that such securities are attractively priced. Such repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, and other factors. The amounts involved in any such repurchases may be material.

We rely mainly on long-term debt obligations to fund our construction activities. We have, to the extent available at acceptable terms, utilized non-recourse debt to fund a significant portion of the capital expenditures and investments required to construct and acquire our electric power plants, distribution companies, and related assets. Our non-recourse financing is designed to limit cross-default risk to the Parent Company or other subsidiaries and affiliates. Our non-recourse long-term debt is a combination of fixed and variable interest rate instruments. Debt is typically denominated in the currency that matches the currency of the revenue expected to be generated from the benefiting project, thereby reducing currency risk. In certain cases, the currency is matched through the use of derivative instruments. The majority of our non-recourse debt is funded by international commercial banks, with debt capacity supplemented by multilaterals and local regional banks.

Given our long-term debt obligations, the Company is subject to interest rate risk on debt balances that accrue interest at variable rates. When possible, the Company will borrow funds at fixed interest rates or hedge its variable rate debt to fix its interest costs on such obligations. In addition, the Company has historically tried to maintain at least 70% of its consolidated long-term obligations at fixed interest rates, including fixing the interest rate through the use of interest rate swaps. These efforts apply to the notional amount of the swaps compared to the amount of related underlying debt. Presently, the Parent Company's only material unhedged exposure to variable interest rate debt relates to $200 million in senior unsecured term loans. Additionally, commercial paper issuances are short term in nature and subject the Parent Company to interest rate risk at the time of refinancing the paper. On a consolidated basis, of the Company's $27 billion of total gross debt outstanding as of December 31, 2023, approximately $9.9 billion accrues interest at variable rates. Brazil holds $2.3 billion of our floating rate non-recourse exposure as variable rate instruments act as a natural hedge against inflation in Brazil. The Company actively hedges its current and expected variable rate exposure through a combination of currently effective and forward starting interest rate swaps. As of December 31, 2023, the total maximum outstanding amount of hedges protecting the company against variable rate exposure was $6.6 billion. These hedges generally provide economic protection through the entire expected life of the projects, regardless of the type of debt issued to finance construction or refinance the projects in the future.

In addition to utilizing non-recourse debt at a subsidiary level when available, the Parent Company provides a portion, or in certain instances all, of the remaining long-term financing or credit required to fund development, construction or acquisition of a particular project. These investments have generally taken the form of equity investments or intercompany loans, which are subordinated to the project's non-recourse loans. We generally obtain the funds for these investments from our cash flows from operations, proceeds from the sales of assets and/or the proceeds from our issuances of debt, common stock, and other securities. Similarly, in certain of our businesses, the Parent Company may provide financial guarantees or other credit support in support of tax equity partnerships or for the benefit of counterparties who have entered into contracts for the purchase or sale of electricity, equipment, or other services with our subsidiaries or lenders. In such circumstances, if a business defaults on its payment or supply obligation, the Parent Company will be responsible for the business' obligations up to the amount provided for in the relevant guarantee or other credit support. As of December 31, 2023, the Parent Company had provided outstanding financial and performance-related guarantees or other credit support commitments to or for the benefit of our businesses, which were limited by the terms of the agreements, of approximately $4 billion in aggregate (excluding those collateralized by letters of credit and other obligations discussed below).

Some counterparties may be unwilling to accept our general unsecured commitments to provide credit support. Accordingly, with respect to both new and existing commitments, the Parent Company may be required to provide some other form of assurance, such as a letter of credit, to backstop or replace our credit support. The Parent Company may not be able to provide adequate assurances to such counterparties. To the extent we are required and able to provide letters of credit or other collateral to such counterparties, this will reduce the amount of credit available to us to meet our other liquidity needs. As of December 31, 2023, we had $235 million in letters of credit under bilateral agreements, $188 million in letters of credit outstanding provided under our unsecured credit facilities, and $124 million in letters of credit outstanding provided under our revolving credit facility. These letters of credit operate to guarantee performance relating to certain project development and construction activities and business operations. During the year ended December 31, 2023, the Parent Company paid letter of credit fees ranging from 1% to 3% per annum on the outstanding amounts.

Additionally, in connection with certain project financings, some of the Company's subsidiaries have expressly undertaken limited obligations and commitments. These contingent contractual obligations are issued at the subsidiary level and are non-recourse to the Parent Company. As of December 31, 2023, the maximum undiscounted potential exposure to guarantees issued by our subsidiaries was $2.8 billion, including $1.8 billion of customary payment guarantees under EPC contracts and other agreements, and $1 billion of tax equity financing related guarantees. In addition, as of December 31, 2023, our subsidiaries had $359 million of letters of credit outstanding.

We expect to continue to seek, where possible, non-recourse debt financing in connection with the assets or businesses that we or our affiliates may develop, construct or acquire. However, depending on local and global market conditions and the unique characteristics of individual businesses, non-recourse debt may not be available on economically attractive terms or at all. If we decide not to provide any additional funding or credit support to a subsidiary project that is under construction or has near-term debt payment obligations and that subsidiary is unable to obtain additional non-recourse debt, such subsidiary may become insolvent, and we may lose our investment in that subsidiary. Additionally, if any of our subsidiaries lose a significant customer, the subsidiary may need to withdraw from a project or restructure the non-recourse debt financing. If we or the subsidiary choose not to proceed with a project or are unable to successfully complete a restructuring of the non-recourse debt, we may lose our investment in that subsidiary.

Many of our subsidiaries depend on timely and continued access to capital markets to manage their liquidity needs. The inability to raise capital on favorable terms, to refinance existing indebtedness or to fund operations and other commitments during times of political or economic uncertainty may have material adverse effects on the financial condition and results of operations of those subsidiaries. In addition, changes in the timing of tariff increases or delays in the regulatory determinations under the relevant concessions could affect the cash flows and results of operations of our businesses.

Long-Term Receivables

As of December 31, 2023, the Company had approximately $193 million of gross accounts receivable classified as *Other noncurrent assets*. These noncurrent receivables mostly consist of accounts receivable in the U.S. and Chile that, pursuant to amended agreements or government resolutions, have collection periods that extend beyond December 31, 2024, or one year from the latest balance sheet date. Noncurrent receivables in the U.S. pertain to the Warrior Run PPA termination agreement and the sale of the Redondo Beach land. The receivables in Chile pertain primarily to revenues recognized on regulated energy contracts that were impacted by the Stabilization Fund created by the Chilean government. See Note 7—*Financing Receivables* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

As of December 31, 2023, the Company had approximately $1.1 billion of loans receivable related to the Mong Duong facility in Vietnam, which was constructed under a BOT contract. This loan receivable represents contract consideration related to the construction of the facility, which was substantially completed in 2015, and will be collected over the 25-year term of the plant's PPA. As of December 31, 2023, Mong Duong met the held-for-sale criteria and the loan receivable balance, net of CECL reserve, was classified in held-for-sale assets. Of the loan receivable balance, $108 million was classified as *Current held-for-sale assets*, and $962 million was classified as *Noncurrent held-for-sale assets*. See Note 20—*Revenue* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Cash Sources and Uses

The primary sources of cash for the Company in the year ended December 31, 2023 were debt financings, cash flows from operating activities, sales to noncontrolling interests, purchases under supplier financing arrangements, and sales of short-term investments. The primary uses of cash in the year ended December 31, 2023 were repayments of debt, capital expenditures, repayments of obligations under supplier financing arrangements, purchases of short-term investments, and acquisitions of business interests.

The primary sources of cash for the Company in the year ended December 31, 2022 were debt financings, cash flows from operating activities, sales of short-term investments, purchases under supplier financing arrangements, and sales to noncontrolling interests. The primary uses of cash in the year ended December 31, 2022 were repayments of debt, capital expenditures, purchases of short-term investments, acquisitions of noncontrolling interests, and purchases of emissions allowances in Bulgaria.

A summary of cash-based activities are as follows (in millions):

	Year Ended December 31, 2023	Year Ended December 31, 2022
Cash Sources:		
Borrowings under the revolving credit facilities	$ 7,103	$ 5,424
Issuance of non-recourse debt	4,521	5,788
Net cash provided by operating activities	3,034	2,715
Sales to noncontrolling interests	1,938	742
Purchases under supplier financing arrangements	1,858	1,042
Issuance of recourse debt	1,400	200
Sale of short-term investments	1,318	1,049
Issuance of preferred shares in subsidiaries	421	60
Proceeds from the sale of business interests, net of cash and restricted cash sold	254	1
Contributions from noncontrolling interests	102	233
Affiliate repayments and returns of capital	5	149
Other	—	25
Total Cash Sources	$ 21,954	$ 17,428
Cash Uses:		
Capital expenditures	$ (7,724)	$ (4,551)
Repayments under the revolving credit facilities	(6,285)	(4,687)
Repayments of non-recourse debt	(2,495)	(3,144)
Repayments of obligations under supplier financing arrangements	(1,491)	(432)
Purchase of short-term investments	(937)	(1,492)
Acquisitions of business interests, net of cash and restricted cash acquired	(542)	(243)
Repayments of recourse debt	(500)	(29)
Dividends paid on AES common stock	(444)	(422)
Distributions to noncontrolling interests	(323)	(265)
Purchase of emissions allowances	(268)	(488)
Contributions and loans to equity affiliates	(178)	(232)
Payments for financing fees	(142)	(120)
Acquisitions of noncontrolling interests	(127)	(602)
Other [(1)]	(595)	(118)
Total Cash Uses	$ (22,051)	$ (16,825)
Net increase (decrease) in Cash, Cash Equivalents, and Restricted Cash	$ (97)	$ 603

(1) Includes the $270 million and $56 million effect of exchange rate changes on cash, cash equivalents and restricted cash for the years ended December 31, 2023 and 2022, respectively. These impacts are primarily related to the devaluation of the Argentine peso as Argentina's economy continued to be highly inflationary. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Foreign Exchange Rates* for further information.

Consolidated Cash Flows

The following table reflects the changes in operating, investing, and financing cash flows for the comparative twelve month periods (in millions):

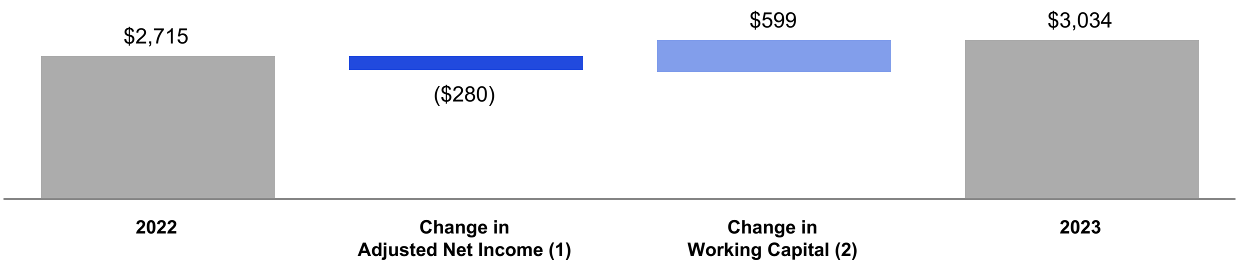
Cash flows provided by (used in):	December 31, 2023	December 31, 2022	$ Change
Operating activities	$ 3,034	$ 2,715	$ 319
Investing activities	(8,188)	(5,836)	(2,352)
Financing activities	5,405	3,758	1,647

Operating Activities

Fiscal Year 2023 versus 2022

Net cash provided by operating activities increased $319 million for the year ended December 31, 2023, compared to December 31, 2022.

Operating Cash Flows
(in millions)



(1) The change in adjusted net income is defined as the variance in *net income*, net of the total *adjustments to net income* as shown on the Consolidated Statements of Cash Flows in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

(2) The change in working capital is defined as the variance in total *changes in operating assets and liabilities* as shown on the Consolidated Statements of Cash Flows in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

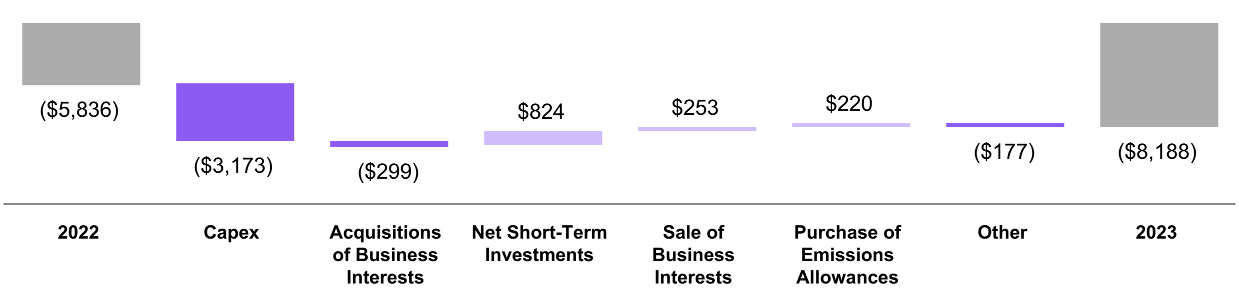
- Adjusted net income decreased $280 million, primarily due to lower margins at our Energy Infrastructure and Renewables SBUs and an increase in interest expense; partially offset by higher margins at our Utilities SBU and an increase in interest income.
- Working capital requirements decreased $599 million, primarily due to a decrease in accounts receivable resulting from higher collections, and decreases in inventory and accounts payable due to lower inventory purchases at lower prices; partially offset by an increase in other assets due to the receivables under the Warrior Run PPA termination agreement and the deferral of purchased power costs in the current year.

Investing Activities

Fiscal Year 2023 versus 2022

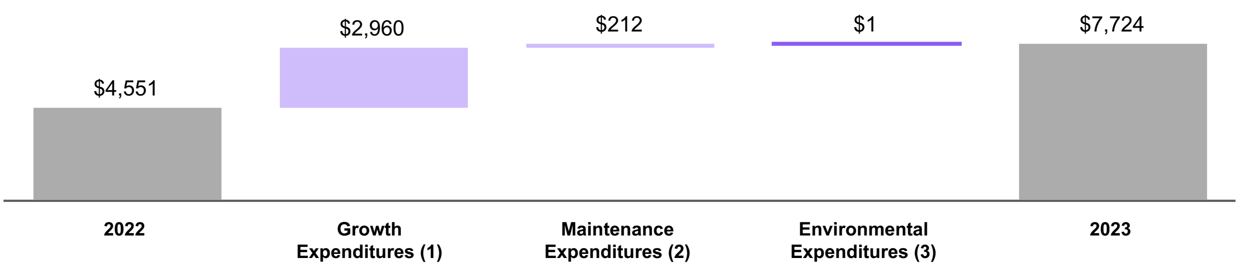
Net cash used in investing activities increased $2.4 billion for the year ended December 31, 2023 compared to December 31, 2022.

Investing Cash Flows
(in millions)



- Acquisitions of business interests increased $299 million, primarily due to the acquisitions of Bellefield and Rexford at AES Clean Energy and Bolero Solar Park at AES Andes; partially offset by the prior year acquisitions of the Cubico II Wind Complex at AES Brasil and Agua Clara in the Dominican Republic.
- Cash from short-term investing activities increased $824 million, primarily as a result of higher short-term investment sales in 2023 to fund the capital expenditures of our renewables projects.
- Proceeds from sales of business interests increased $253 million due to proceeds from the partial sale of our ownership interests in Fluence and sPower OpCo B.
- Purchases of emissions allowances decreased $220 million, primarily in Bulgaria as a result of lower CO_2 purchases due to lower production.
- Capital expenditures increased $3.2 billion, discussed further below.

Capital Expenditures
(in millions)



(1) Growth expenditures generally include expenditures related to development projects in construction, expenditures that increase capacity of a facility beyond the original design, and investments in general load growth or system modernization.

(2) Maintenance expenditures generally include expenditures that are necessary to maintain regular operations or net maximum capacity of a facility.

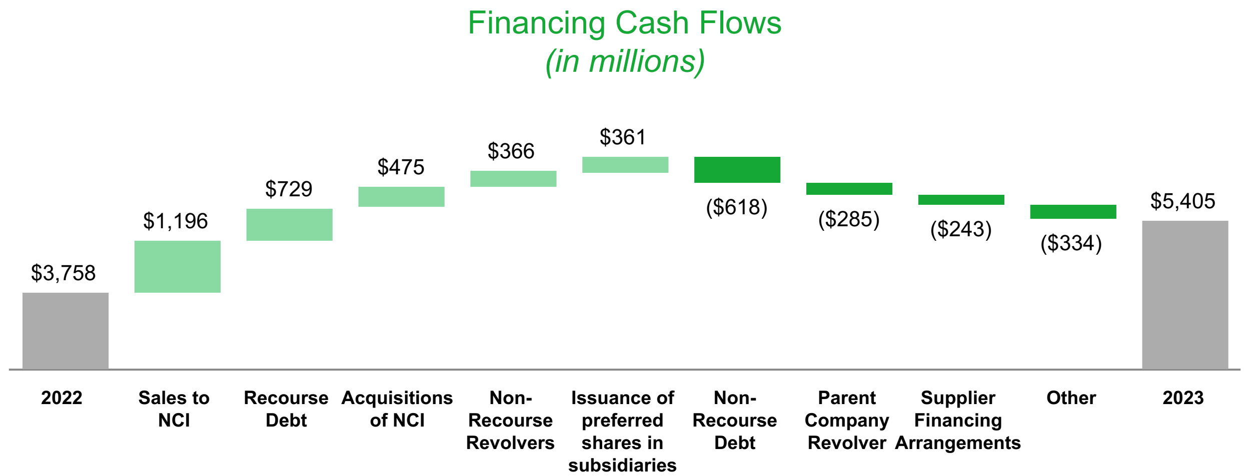
(3) Environmental expenditures generally include expenditures to comply with environmental laws and regulations, expenditures for safety programs and other expenditures to ensure a facility continues to operate in an environmentally responsible manner.

- Growth expenditures increased $3 billion, primarily driven by an increase in U.S. renewables projects.
- Maintenance expenditures increased $212 million, primarily due to higher transmission and distribution and renewables project investments at our Utilities SBU and increased expenditures for hydro and wind plants at our Renewables SBU.
- Environmental expenditures increased $1 million, with no material drivers.

Financing Activities

Fiscal Year 2023 versus 2022

Net cash provided by financing activities increased $1.6 billion for the year ended December 31, 2023 compared to December 31, 2022.



See Notes 11—*Debt* and 17—*Equity* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for more information regarding significant debt and equity transactions, respectively.

- The $1.2 billion impact from sales to noncontrolling interests is primarily due to proceeds received at AES Clean Energy from the sales of ownership in project companies to tax equity investors, the sale of a 20% interest in AES Dominicana and a 35% interest in Colon, and from an increase in sales under the Chile Renovables renewable partnership with GIP; partially offset by the prior year sale of a 14.9% ownership interest in Southland Energy.
- The $729 million impact from recourse debt is primarily due to the issuance of senior notes due in 2028 by the Parent Company.
- The $475 million impact from acquisitions of noncontrolling interests is mainly due to the prior year acquisition of an additional 32% ownership interest in AES Andes; partially offset by the final installment payment for the 2021 acquisition of the remaining 49.9% noncontrolling ownership interest in Colon.
- The $366 million impact from non-recourse revolving credit facilities is primarily due to an increase in borrowings at our Energy Infrastructure SBU.
- The $361 million impact from issuance of preferred shares in subsidiaries is due to the proceeds received from the issuance of preferred shares to GIP, as part of the Chile Renovables renewable partnership, and the issuance of preferred shares to HASI at AES Renewable Holdings for OpCo 1; partially offset by proceeds received in the prior year for issuances of preferred shares at AES Brasil.
- The $618 million impact from non-recourse debt transactions is mainly due to lower net borrowings at the Energy Infrastructure SBU and higher net repayments at Corporate; partially offset by higher net borrowings at the Renewables SBU.
- The $285 million impact from the Parent Company revolver is primarily due to higher net repayments in the current year.
- The $243 million impact from supplier financing arrangements is primarily due to higher net repayments at the Renewables and Energy Infrastructure SBUs.

Parent Company Liquidity

The following discussion is included as a useful measure of the liquidity available to The AES Corporation, or the Parent Company, given the non-recourse nature of most of our indebtedness. Parent Company Liquidity as outlined below is a non-GAAP measure and should not be construed as an alternative to *Cash and cash equivalents,* which is determined in accordance with GAAP. Parent Company Liquidity may differ from similarly titled measures used by other companies. The principal sources of liquidity at the Parent Company level are dividends and other distributions from our subsidiaries, including refinancing proceeds; proceeds from debt and equity financings at the Parent Company level, including availability under our revolving credit facility and commercial paper program; and proceeds from asset sales. The Parent Company credit facility and commercial paper program are generally used for short-term cash needs to bridge the timing of distributions from subsidiaries. Cash requirements at the Parent Company level are primarily to fund interest and principal repayments of debt, construction commitments, other equity commitments, acquisitions, taxes, Parent Company overhead and development costs, and dividends on common stock.

The Company defines Parent Company Liquidity as cash available to the Parent Company, including cash at qualified holding companies, plus available borrowings under our existing credit facility and commercial paper program. The cash held at qualified holding companies represents cash sent to subsidiaries of the Company domiciled outside of the U.S. Such subsidiaries have no contractual restrictions on their ability to send cash to the Parent Company. Parent Company Liquidity is reconciled to its most directly comparable GAAP financial measure, *Cash and cash equivalents*, at the periods indicated as follows (in millions):

	December 31, 2023	December 31, 2022
Consolidated cash and cash equivalents	$ 1,426	$ 1,374
Less: Cash and cash equivalents at subsidiaries	(1,393)	(1,350)
Parent Company and qualified holding companies' cash and cash equivalents	33	24
Commitments under the Parent Company credit facility	1,500	1,500
Less: Letters of credit under the credit facility	(124)	(34)
Less: Borrowings under the credit facility	—	(325)
Borrowings available under the Parent Company credit facility	1,376	1,141
Total Parent Company Liquidity	$ 1,409	$ 1,165

The Parent Company paid dividends of $0.66 per outstanding share to its common stockholders during the year ended December 31, 2023. While we intend to continue payment of dividends and believe we will have sufficient liquidity to do so, we can provide no assurance that we will continue to pay dividends, or if continued, the amount of such dividends.

Recourse Debt

Our total recourse debt was $4.5 billion and $3.9 billion as of December 31, 2023 and 2022, respectively. See Note 11—*Debt* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional detail.

We believe that our sources of liquidity will be adequate to meet our needs for the foreseeable future. This belief is based on a number of material assumptions, including, without limitation, assumptions about our ability to access the capital markets, the operating and financial performance of our subsidiaries, currency exchange rates, power market pool prices, and the ability of our subsidiaries to pay dividends. In addition, our subsidiaries' ability to declare and pay cash dividends to us (at the Parent Company level) is subject to certain limitations contained in loans, governmental provisions, and other agreements. We can provide no assurance that these sources will be available when needed or that the actual cash requirements will not be greater than anticipated. We have met our interim needs for shorter-term and working capital financing at the Parent Company level with our revolving credit facility and commercial paper program. See Item 1A.—*Risk Factors—The AES Corporation's ability to make payments on its outstanding indebtedness is dependent upon the receipt of funds from our subsidiaries,* of this Form 10-K.

Various debt instruments at the Parent Company level, including our revolving credit facility and commercial paper program, contain certain restrictive covenants. The covenants provide for, among other items, limitations on other indebtedness, liens, investments and guarantees; limitations on dividends, stock repurchases and other equity transactions; restrictions and limitations on mergers and acquisitions, sales of assets, leases, transactions with affiliates and off-balance sheet and derivative arrangements; maintenance of certain financial ratios; and financial and other reporting requirements. As of December 31, 2023, we were in compliance with these covenants at the Parent Company level.

Non-Recourse Debt

While the lenders under our non-recourse debt financings generally do not have direct recourse to the Parent Company, defaults thereunder can still have important consequences for our results of operations and liquidity, including, without limitation:

- reducing our cash flows as the subsidiary will typically be prohibited from distributing cash to the Parent Company during the time period of any default;
- triggering our obligation to make payments under any financial guarantee, letter of credit or other credit support we have provided to or on behalf of such subsidiary;
- causing us to record a loss in the event the lender forecloses on the assets; and
- triggering defaults in our outstanding debt at the Parent Company.

For example, our revolving credit facility and outstanding debt securities at the Parent Company include events of default for certain bankruptcy-related events involving material subsidiaries. In addition, our revolving credit agreement at the Parent Company includes events of default related to payment defaults and accelerations of outstanding debt of material subsidiaries.

Some of our subsidiaries are currently in default with respect to all or a portion of their outstanding indebtedness. The total non-recourse debt classified as current in the accompanying Consolidated Balance Sheets amounts to $3.9 billion. The portion of current debt related to such defaults was $325 million at December 31, 2023, all of which was non-recourse debt related to four subsidiaries — AES Mexico Generation Holdings, AES Puerto Rico, AES Ilumina, and AES Jordan Solar. Defaults at AES Puerto Rico are covenant and payment defaults. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Macroeconomic and Political—Puerto Rico* for additional detail. All other defaults are not payment defaults, but are instead technical defaults triggered by failure to comply with other covenants or other conditions contained in the non-recourse debt documents. See Note 11—*Debt* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional detail.

None of the subsidiaries that are currently in default are subsidiaries that met the applicable definition of materiality under the Parent Company's debt agreements as of December 31, 2023, in order for such defaults to trigger an event of default or permit acceleration under the Parent Company's indebtedness. However, as a result of additional dispositions of assets, other significant reductions in asset carrying values or other matters in the future that may impact our financial position and results of operations or the financial position of the individual subsidiary, it is possible that one or more of these subsidiaries could fall within the definition of a "material subsidiary" and thereby trigger an event of default and possible acceleration of the indebtedness under the Parent Company's outstanding debt securities. A material subsidiary is defined in the Parent Company's revolving credit agreement as any business that contributed 20% or more of the Parent Company's total cash distributions from businesses for the four most recently completed fiscal quarters. As of December 31, 2023, none of the defaults listed above resulted in a cross-default under the recourse debt of the Parent Company. Furthermore, none of the non-recourse debt in default listed above is guaranteed by the Parent Company.

Contractual Obligations and Contingent Contractual Obligations

A summary of our contractual obligations, commitments and other liabilities as of December 31, 2023 is presented below (in millions):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years	Other	Footnote Reference[5]
Debt obligations [1] [2]	$ 26,977	$ 4,135	$ 7,447	$ 4,398	$ 10,997	$ —	11
Interest payments on long-term debt [3]	12,650	1,419	2,278	1,521	7,432	—	n/a
Finance lease obligations [2]	618	14	29	30	545	—	14
Operating lease obligations [2]	1,209	56	88	79	986	—	14
Electricity obligations	10,099	1,222	1,662	1,342	5,873	—	12
Fuel obligations	11,065	2,069	2,844	2,278	3,874	—	12
Other purchase obligations	9,549	4,698	1,784	1,347	1,720	—	12
Other long-term liabilities reflected on AES' consolidated balance sheet under GAAP [2] [4]	1,022	—	492	61	459	10	n/a
Total	$ 73,189	$ 13,613	$16,624	$11,056	$ 31,886	$ 10	

(1) Includes recourse and non-recourse debt presented on the Consolidated Balance Sheets. These amounts exclude finance lease liabilities which are included in the finance lease category.

(2) Excludes any businesses classified as held-for-sale. See Note 24—*Held-for-Sale and Dispositions* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional information related to held-for-sale businesses.

(3) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2023 and do not reflect anticipated future refinancing, early redemptions or new debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2023.

(4) These amounts do not include current liabilities on the Consolidated Balance Sheets except for the current portion of uncertain tax obligations. Noncurrent uncertain tax obligations are reflected in the "Other" column of the table above as the Company is not able to reasonably estimate the timing of the future payments. In addition, these amounts do not include: (1) regulatory liabilities (See Note 10—*Regulatory Assets and Liabilities*), (2) contingencies (See Note 13—*Contingencies*), (3) pension and other postretirement employee benefit liabilities (see Note 15—*Benefit Plans*), (4) derivatives and incentive compensation (See Note 6—*Derivative Instruments and Hedging Activities*) or (5) any taxes (See Note 23—*Income Taxes*) except for uncertain tax obligations, as the Company is not able to reasonably estimate the timing of future payments. See the indicated notes to the Consolidated Financial Statements included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional information on the items excluded.

(5) For further information see the note referenced below in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

The following table presents our Parent Company's contingent contractual obligations as of December 31, 2023:

Contingent Contractual Obligations	**Maximum Exposure (in millions)**	**Number of Agreements**	**Maximum Exposure Range for Each Agreement (in millions)**
Guarantees and commitments	$ 3,978	90	< $1 — 970
Letters of credit under bilateral agreements	235	4	$54— 64
Letters of credit under the unsecured credit facilities	188	31	< $1 — 70
Letters of credit under the revolving credit facility	124	17	< $1 — 40
Surety bonds	2	2	< $1 — $1
Total	$ 4,527	144	

Additionally, some of the Company's subsidiaries have contingent contractual obligations that are non-recourse to the Parent Company. As of December 31, 2023, the maximum undiscounted potential exposure to guarantees issued by our subsidiaries was $2.8 billion, including $1.8 billion of customary payment guarantees under EPC contracts and other agreements, and $1 billion of tax equity financing related guarantees. In addition, as of December 31, 2023, our subsidiaries had $359 million of letters of credit outstanding.

We have a diverse portfolio of performance-related contingent contractual obligations. These obligations are designed to cover potential risks and only require payment if certain targets are not met or certain contingencies occur. The risks associated with these obligations include change of control, construction cost overruns, subsidiary default, political risk, tax indemnities, spot market power prices, sponsor support, and liquidated damages under power sales agreements for projects in development, in operation and under construction. While we do not expect that we will be required to fund any material amounts under these contingent contractual obligations beyond 2023, many of the events which would give rise to such obligations are beyond our control. We can provide no assurance that we will be able to fund our obligations under these contingent contractual obligations if we are required to make substantial payments thereunder.

Critical Accounting Policies and Estimates

The Consolidated Financial Statements of AES are prepared in conformity with U.S. GAAP, which requires the use of estimates, judgments, and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the periods presented. AES' significant accounting policies are described in Note 1—*General and Summary of Significant Accounting Policies* to the Consolidated Financial Statements included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

An accounting estimate is considered critical if the estimate requires management to make assumptions about matters that were highly uncertain at the time the estimate was made, different estimates reasonably could have been used, or the impact of the estimates and assumptions on financial condition or operating performance is material.

Management believes that the accounting estimates employed are appropriate and the resulting balances are reasonable; however, actual results could materially differ from the original estimates, requiring adjustments to these balances in future periods. Management has discussed these critical accounting policies with the Audit Committee, as appropriate. Listed below are the Company's most significant critical accounting estimates and assumptions used in the preparation of the Consolidated Financial Statements.

Income Taxes — We are subject to income taxes in both the U.S. and numerous foreign jurisdictions. Our worldwide income tax provision requires significant judgment and is based on calculations and assumptions that are subject to examination by the Internal Revenue Service and other taxing authorities. Certain of the Company's subsidiaries are under examination by relevant taxing authorities for various tax years. The Company regularly assesses the potential outcome of these examinations in each tax jurisdiction when determining the adequacy of the provision for income taxes. Accounting guidance for uncertainty in income taxes prescribes a more likely than not recognition threshold. Tax reserves have been established, which the Company believes to be adequate in relation to the potential for additional assessments. Once established, reserves are adjusted only when there is more information available or when an event occurs necessitating a change to the reserves. While the Company believes that the amounts of the tax estimates are reasonable, it is possible that the ultimate outcome of current or future examinations may be materially different than the reserve amounts.

Because we have a wide range of statutory tax rates in the multiple jurisdictions in which we operate, any changes in our geographical earnings mix could materially impact our effective tax rate. Furthermore, our tax position could be adversely impacted by changes in tax laws, tax treaties or tax regulations, or the interpretation or enforcement thereof and such changes may be more likely or become more likely in view of recent economic trends in certain of the jurisdictions in which we operate.

In addition, no taxes have been recorded on undistributed earnings for certain of our non-U.S. subsidiaries to the extent such earnings are considered to be indefinitely reinvested in the operations of those subsidiaries. Should the earnings be remitted as dividends, the Company may be subject to additional foreign withholding and state income taxes.

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax bases. The Company establishes a valuation allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. The Company has elected to treat GILTI as an expense in the period in which the tax is accrued. Accordingly, no deferred tax assets or liabilities are recorded related to GILTI.

In addition, the Company has elected an accounting policy not to consider the effects of being subject to the corporate alternative minimum tax in future periods when assessing the realizability of our deferred tax assets, carryforwards, and tax credits. Any effect on the realization of deferred tax assets will be recognized in the period they arise.

The Company accounts for tax credits that it will retain or transfer as a reduction in income tax expense by either including the expected amount of the tax credit to be claimed or the cash to be received when transferred, respectively, in the calculation of its annual effective tax rate. The estimated tax credits are updated on a quarterly basis, with the year-end calculation including only the tax credits that are associated with projects placed in service, comprising credits claimed or transferred during the year. In assessing realizability for credits to be transferred, the Company includes cash it anticipates receiving in establishing any valuation allowance and establishes a valuation allowance equal to its best estimate of any discount on the transfer. The receipt of cash from the transfer of tax credits is treated as an operating cash inflow.

Impairments — Our accounting policies on goodwill and long-lived assets, including events that lead to possible impairment, are described in detail in Note 1—*General and Summary of Significant Accounting Policies*, included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K. The Company makes considerable judgments in its impairment evaluations of goodwill and long-lived assets, starting with determining if an impairment indicator exists. The Company exercises judgment in determining if these indicators or events represent an impairment indicator requiring the computation of the fair value of goodwill and/or the recoverability of long-lived assets. The fair value determination is typically the most judgmental part in an impairment evaluation. Please see *Fair Value* below for further detail.

As part of the impairment evaluation process, management analyzes the sensitivity of fair value to various underlying assumptions. The level of scrutiny increases as the surplus of fair value above carrying amount decreases or becomes negative. Changes in any of these assumptions could result in management reaching a different conclusion regarding the potential impairment, which could be material. Our impairment evaluations inherently involve uncertainties from uncontrollable events that could positively or negatively impact the anticipated future economic and operating conditions.

Further discussion of the impairment charges recognized by the Company can be found within Note 9—*Goodwill and Other Intangible Assets* and Note 22—*Asset Impairment Expense* to the Consolidated Financial Statements included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

Depreciation — Depreciation, after consideration of salvage value and asset retirement obligations, is computed using the straight-line method over the estimated useful lives of the assets, which are determined on a composite or component basis. The Company considers many factors in its estimate of useful lives, including expected usage, physical deterioration, technological changes, existence and length of off-taker agreements, and laws and regulations, among others. In certain circumstances, these estimates involve significant judgment and require management to forecast the impact of relevant factors over an extended time horizon.

Useful life estimates are continually evaluated for appropriateness as changes in the relevant factors arise, including when a long-lived asset group is tested for recoverability. Depreciation studies are performed periodically for assets subject to composite depreciation. Any change to useful lives is considered a change in accounting estimate and is made on a prospective basis.

Fair Value — For information regarding the fair value hierarchy, see Note 1—*General and Summary of Significant Accounting Policies* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

Fair Value of Financial Instruments — A significant number of the Company's financial instruments are carried at fair value with changes in fair value recognized in earnings or other comprehensive income each period. Investments are generally fair valued based on quoted market prices or other observable market data such as interest rate indices. The Company's investments are primarily certificates of deposit and mutual funds. Derivatives are valued using observable data as inputs into internal valuation models. The Company's derivatives primarily consist of interest rate swaps, foreign currency instruments, and commodity and embedded derivatives. Additional discussion regarding the nature of these financial instruments and valuation techniques can be found in Note 5—*Fair Value* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

Fair Value of Nonfinancial Assets and Liabilities — Significant estimates are made in determining the fair value of long-lived tangible and intangible assets (i.e., property, plant and equipment, intangible assets and goodwill) during the impairment evaluation process. In addition, the relevant accounting guidance requires the Company to recognize the majority of assets acquired and liabilities assumed in a business combination and asset acquisitions by VIEs at fair value.

The Company may engage an independent valuation firm to assist management with the valuation. The Company generally utilizes the income approach to value nonfinancial assets and liabilities, specifically a Discounted Cash Flow ("DCF") model to estimate fair value by discounting cash flow forecasts, adjusted to reflect market participant assumptions, to the extent necessary, at an appropriate discount rate.

Management applies considerable judgment in selecting several input assumptions during the development of our cash flow forecasts. Examples of the input assumptions that our forecasts are sensitive to include macroeconomic factors such as growth rates, industry demand, inflation, exchange rates, power prices, changes in interest rates, and commodity prices. Whenever appropriate, management obtains these input assumptions from observable market data sources (e.g., Economic Intelligence Unit) and extrapolates the market information if an input assumption is not observable for the entire forecast period. Many of these input assumptions are dependent on other economic assumptions, which are often derived from statistical economic models with inherent limitations such as estimation differences. Further, several input assumptions are based on historical trends which often do not recur. It is not uncommon that different market data sources have different views of the macroeconomic factor expectations and related assumptions. As a result, macroeconomic factors and related assumptions are often available in a narrow range; however, in some situations these ranges become wide and the use of a different set of input assumptions could produce significantly different budgets and cash flow forecasts.

A considerable amount of judgment is also applied in the estimation of the discount rate used in the DCF model. To the extent practical, inputs to the discount rate are obtained from market data sources (e.g., Bloomberg). The Company selects and uses a set of publicly traded companies from the relevant industry to estimate the discount rate inputs. Management applies judgment in the selection of such companies based on its view of the most likely market participants. It is reasonably possible that the selection of a different set of likely market participants could produce different input assumptions and result in the use of a different discount rate.

Accounting for Derivative Instruments and Hedging Activities — We enter into various derivative transactions in order to hedge our exposure to certain market risks. We primarily use derivative instruments to manage our interest rate, commodity, and foreign currency exposures. We do not enter into derivative transactions for trading purposes. See Note 6—*Derivative Instruments and Hedging Activities* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information on the classification.

The fair value measurement standard requires the Company to consider and reflect the assumptions of market participants in the fair value calculation. These factors include nonperformance risk (the risk that the obligation will not be fulfilled) and credit risk, both of the reporting entity (for liabilities) and of the counterparty (for assets). Credit risk for AES is evaluated at the level of the entity that is party to the contract. Nonperformance risk on the Company's derivative instruments is an adjustment to the fair value position that is derived from internally developed valuation models that utilize market inputs that may or may not be observable.

As a result of uncertainty, complexity, and judgment, accounting estimates related to derivative accounting could result in material changes to our financial statements under different conditions or utilizing different assumptions. As a part of accounting for these derivatives, we make estimates concerning nonperformance, volatilities, market liquidity, future commodity prices, interest rates, credit ratings, and future foreign exchange rates. Refer to Note 5—*Fair Value* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional details.

The fair value of our derivative portfolio is generally determined using internal and third party valuation models, most of which are based on observable market inputs, including interest rate curves and forward and spot prices for currencies and commodities. The Company derives most of its financial instrument market assumptions from market efficient data sources (e.g., Bloomberg, Reuters, and Platt's). In some cases, where market data is not readily available, management uses comparable market sources and empirical evidence to derive market assumptions to determine a financial instrument's fair value. In certain instances, published pricing may not extend through the remaining term of the contract, and management must make assumptions to extrapolate the curve. Specifically, where there is limited forward curve data with respect to foreign exchange contracts beyond the traded points, the Company utilizes the interest rate differential approach to construct the remaining portion of the forward curve. For individual contracts, the use of different valuation models or assumptions could have a material effect on the calculated fair value.

Regulatory Assets — Management continually assesses whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities, and the status of any pending or potential deregulation legislation. If future recovery of costs ceases to be probable, any asset write-offs would be required to be recognized in operating income.

Consolidation — The Company enters into transactions impacting the Company's equity interests in its affiliates. In connection with each transaction, the Company must determine whether the transaction impacts the Company's consolidation conclusion by first determining whether the transaction should be evaluated under the variable interest model or the voting model. In determining which consolidation model applies to the transaction, the Company is required to make judgments about how the entity operates, the most significant of which are whether (i) the entity has sufficient equity to finance its activities, (ii) the equity holders, as a group, have the characteristics of a controlling financial interest, and (iii) whether the entity has non-substantive voting rights.

If the entity is determined to be a variable interest entity, the most significant judgment in determining whether the Company must consolidate the entity is whether the Company, including its related parties and de facto agents, collectively have power and benefits. If AES is determined to have power and benefits, the entity will be consolidated by AES.

Alternatively, if the entity is determined to be a voting model entity, the most significant judgments involve determining whether the non-AES shareholders have substantive participating rights. The assessment of shareholder rights and whether they are substantive participating rights requires significant judgment since the rights provided under shareholders' agreements may include selecting, terminating, and setting the compensation of management responsible for implementing the subsidiary's policies and procedures, and establishing operating and capital decisions of the entity, including budgets, in the ordinary course of business. On the other hand, if shareholder rights are only protective in nature (referred to as protective rights), then such rights would not overcome the presumption that the owner of a majority voting interest shall consolidate its investee. Significant judgment is required to determine whether minority rights represent substantive participating rights or protective rights that do not affect the evaluation of control. While both represent an approval or veto right, a distinguishing factor is the underlying activity or action to which the right relates.

Pension and Other Postretirement Plans — The Company recognizes a net asset or liability reflecting the funded status of pension and other postretirement plans with current-year changes in actuarial gains or losses recognized in AOCL, except for those plans at certain of the Company's regulated utilities that can recover portions of their pension and postretirement obligations through future rates. The valuation of the Company's benefit obligation, fair value of plan assets, and net periodic benefit costs requires various estimates and assumptions, the most significant of which include the discount rate and expected return on plan assets. These assumptions are reviewed by the Company on an annual basis. Refer to Note 1—*General and Summary of Significant Accounting Policies* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Revenue Recognition — The Company recognizes revenue to depict the transfer of energy, capacity, and other services to customers in an amount that reflects the consideration to which we expect to be entitled. In applying the revenue model, we determine whether the sale of energy, capacity, and other services represent a single performance obligation based on the individual market and terms of the contract. Generally, the promise to transfer energy and capacity represent a performance obligation that is satisfied over time and meets the criteria to be accounted for as a series of distinct goods or services. Progress toward satisfaction of a performance obligation is measured using output methods, such as MWhs delivered or MWs made available, and when we are entitled to consideration in an amount that corresponds directly to the value of our performance completed to date, we recognize revenue in the amount to which we have the right to invoice. For further information regarding the nature of our revenue streams and our critical accounting policies affecting revenue recognition, see Note 1—*General and Summary of Significant Accounting Policies* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

Leases — The Company recognizes operating and finance right-of-use assets and lease liabilities on the Consolidated Balance Sheets for most leases with an initial term of greater than 12 months. Lease liabilities and their corresponding right-of-use assets are recorded based on the present value of lease payments over the expected lease term. Our subsidiaries' incremental borrowing rates are used in determining the present value of lease payments when the implicit rate is not readily determinable. Certain adjustments to the right-of-use asset may be required for items such as prepayments, lease incentives, or initial direct costs. For further information regarding the nature of our leases and our critical accounting policies affecting leases, see Note 1—*General and Summary of Significant Accounting Policies* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

Credit Losses — The Company uses a forward-looking "expected loss" model to recognize allowances for credit losses on trade and other receivables, held-to-maturity debt securities, loans, and other instruments. For available-for-sale debt securities with unrealized losses, the Company continues to measure impairments of available-for-sale securities as was done under previous GAAP, except that unrealized losses due to credit-related factors are now recognized as an allowance on the Consolidated Balance Sheet with a corresponding adjustment to earnings in the Consolidated Statements of Operations. For further information regarding credit losses, see Note 1—*General and Summary of Significant Accounting Policies* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

New Accounting Pronouncements

See Note 1—*General and Summary of Significant Accounting Policies* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information about new accounting pronouncements adopted during 2023 and accounting pronouncements issued, but not yet effective.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Overview Regarding Market Risks

Our businesses are exposed to, and proactively manage market risk. Market risk is the potential loss that may result from market changes associated with AES power generation or with existing or forecasted financial or commodity transactions. Our primary market risk exposure is to the price of commodities, particularly electricity, natural gas, coal, and environmental credits. AES is also exposed to fluctuations in interest rates and foreign currency exchange rates associated primarily with outstanding and expected future issuances and borrowing, and from investments in foreign subsidiaries and affiliates. We enter into various transactions, including derivatives, in order to hedge our exposure to these market risks.

The disclosures presented in this Item 7A are based upon a number of assumptions; actual effects may differ. The safe harbor provided in Section 27A of the Securities Act of 1933 and Section 21E of the Exchange Act shall apply to the disclosures contained in this Item 7A. For further information regarding market risk, see Item 1A.—*Risk Factors*, *Fluctuations in currency exchange rates may impact our financial results and position*; *Wholesale power prices may experience significant volatility in our markets which could impact our operations and opportunities for future growth; We may not be adequately hedged against our exposure to changes in commodity prices or interest rates; and Certain of our businesses are sensitive to variations in weather and hydrology* of this 2023 Form 10-K.

Commodity Price Risk

Although we prefer to hedge our exposure to the impact of market fluctuations in the price of commodities, some of our generation businesses operate under short-term sales, have contracted electricity obligations greater than supply, or operate under contract sales that leave an unhedged exposure on some of our capacity or through imperfect fuel pass-throughs. These businesses subject our operational results to the volatility of prices for electricity, fuels, and environmental credits in competitive markets. In addition, our businesses are exposed to lower electricity prices due to increased competition, including from renewable sources such as wind and solar, because of lower costs of entry and lower variable costs. We employ risk management strategies to hedge our financial performance against these effects. The implementation of these strategies can involve the use of physical and financial commodity contracts, futures, swaps, and options. We have some natural offsets across our businesses such that low commodity prices may benefit certain businesses and be a cost to others. Exposures are not perfectly linear or symmetric. The sensitivities are affected by a number of local or indirect market factors. Examples of these factors include hydrology, local energy market supply/demand balances, regional fuel supply issues, regional competition, bidding strategies, and regulatory interventions such as price caps. Volume variation also affects our commodity exposure. The volume sold under contracts or retail concessions can vary based on weather and economic conditions, resulting in a higher or lower volume of sales in spot markets. Thermal unit availability and hydrology can affect the generation output available for sale and can affect the marginal unit setting power prices.

As of December 31, 2023, we project pre-tax earnings exposure on a 10% increase in commodity prices to be less than a $30 million gain for power, less than $15 million loss for gas, and less than $10 million loss for coal. The sensitivities are calculated using industry-standard valuation techniques to revalue all transactions (physical and financial commodity transactions) in the portfolio for a change in the underlying prices the transactions are exposed to and excludes correlation effects, including those due to renewable resource availability. The models reference market prices of commodities across future periods and associated volatility of these market prices. Prices and volatilities are predominantly based on observable market prices.

Exposures at individual businesses will change as new contracts or financial hedges are executed, and our sensitivity to changes in commodity prices generally increases in later years with reduced hedge levels at some of our businesses.

In the Energy Infrastructure SBU, the generation businesses are largely contracted, but may have residual risk to the extent contracts are not perfectly indexed to the business drivers. In California, our Southland once-through cooling generation units ("Legacy Assets") in Long Beach and Huntington Beach have been extended to operate through 2026 under capacity contracts with the State as part of the Strategic Reserve program. Our facility in Redondo Beach has been retired effective January 1, 2024. Our ability to operate the Long Beach facility at full capacity through 2025 was approved under Tentative Time Schedule Order coverage in November 2023. Approval to operate Long Beach through 2026 will be subject to review with State Agencies. Our Southland combined cycle gas turbine (Southland Energy) units benefit from higher power and lower gas prices, depending on the contracted or hedge position. The AES Andes business in Chile owns assets in the central and northern regions of the country and has a portfolio of contract sales in both. A significant portion of our PPAs through 2024 include mechanisms of indexation that adjust the price of energy based on fluctuations in the price of coal, with an index defined by the National Energy Commission based on the physical coal imports for the energy system. This mechanism mitigates exposures to changes in the price of fuel. The increasing share of renewable energy in Chile's power market may reduce reliance on thermal units and impact power price volatility, which could impact our cost to serve certain unregulated PPAs. In the Dominican Republic, we own natural gas plants contracted under a portfolio of contract sales, and both contract and spot prices may move with commodity prices through 2024. Our thermal asset in Panama has PPAs with distribution companies which matches the term of the LNG supply agreement of such thermal assets. New entrants into the Panama thermal generation market could impact the dispatch of existing generation, requiring purchases in the spot market to satisfy the PPA obligations. Contract levels do not always match our generation availability or needs, and our assets may be sellers of spot prices in excess of contract levels or a net buyer in the spot market to satisfy contract obligations, which could impact existing fuel supply commitments. Our assets operating in Vietnam and Bulgaria have minimal exposure to commodity price risk as they have no or minor merchant exposure and fuel is subject to a pass-through mechanism.

In the Renewables SBU, our businesses have commodity exposure on unhedged volumes and resource volatility and benefit from higher power prices, where generation exceeds contracted levels. In Colombia, we operate under a shorter-term sales strategy with spot market exposure for uncontracted volumes. Because we own hydroelectric assets there, contracts are not indexed to fuel. In Brazil, the majority of the hydroelectric and other renewable generating facility volumes are covered by contract sales. Under normal hydrological volatility, spot price risk is mitigated through a regulated sharing mechanism across all hydroelectric generators in the country. Under drier conditions, the sharing mechanism may not be sufficient to cover the business' contract position, and therefore it may have to purchase power at spot prices driven by the cost of thermal generation. Our Renewables businesses in Panama are highly contracted under financial and load-following PPA type structures, exposing the business to hydrology-based variance. To the extent hydrological inflows are greater than or less than the contract volumes, the business will be sensitive to changes in spot power prices which may be driven by oil and natural gas prices in some time periods.

Foreign Exchange Rate Risk

We operate in multiple countries and as such are subject to volatility in exchange rates at varying degrees at the subsidiary level and between our functional currency, the USD, and currencies of the countries in which we operate.

In the normal course of business, we are exposed to foreign currency risk and other foreign operations risks that arise from investments in foreign subsidiaries and affiliates. A key component of these risks stems from the fact that some of our foreign subsidiaries and affiliates utilize currencies other than our consolidated reporting currency, the USD. Additionally, certain of our foreign subsidiaries and affiliates have entered into monetary obligations in USD or currencies other than their own functional currencies. Certain of our foreign subsidiaries calculate and pay taxes in currencies other than their own functional currency. We have varying degrees of exposure to changes in the exchange rate between the USD and the following currencies: Argentine peso, Brazilian real, Chilean peso, Colombian peso, Dominican peso, Euro, and Mexican peso. Our exposure to certain of these currencies may be material. These subsidiaries and affiliates attempt to limit potential foreign exchange exposure by entering into revenue contracts that adjust to changes in foreign exchange rates. We also use foreign currency forwards, swaps, and options where possible to manage our risk related to certain foreign currency fluctuations.

AES enters into foreign currency hedges to protect economic value of the business and minimize the impact of foreign exchange rate fluctuations to AES' portfolio. While protecting cash flows, the hedging strategy is also designed to reduce forward-looking earnings foreign exchange volatility. Due to variation of timing and amount between cash distributions and earnings exposure, the hedge impact may not fully cover the earnings exposure on a realized basis, which could result in greater volatility in earnings.

AES has unhedged forward-looking earnings foreign exchange deterioration risk from the Argentine peso that could be material. Additionally, as of December 31, 2023, assuming a 10% USD appreciation, cash distributions attributable to foreign subsidiaries in the Brazilian real, Colombian peso, and Euro, individually, may be exposed to exchange rate movement of less than a $5 million gain. These numbers have been produced by applying a one-time 10% USD appreciation to forecasted exposed cash distributions for 2024 coming from the respective subsidiaries exposed to the currencies listed above, net of the impact of outstanding hedges and holding all other variables constant. The numbers presented above are net of any transactional gains or losses. These sensitivities may change in the future as new hedges are executed or existing hedges are unwound. Additionally, updates to the forecasted cash distributions exposed to foreign exchange risk may result in further modification. The sensitivities presented do not capture the impacts of any administrative market restrictions or currency inconvertibility.

Interest Rate Risks

We are exposed to risk resulting from changes in interest rates primarily because of our current and expected future issuance of debt and borrowing.

Decisions on the fixed-floating debt mix are made to be consistent with the risk factors faced by individual businesses or plants. Depending on whether a plant’s capacity payments or revenue stream is fixed or varies with inflation, we partially hedge against interest rate fluctuations by arranging fixed-rate or variable-rate financing. In certain cases, particularly for non-recourse financing, we execute interest rate swap, cap, and floor agreements to effectively fix or limit the interest rate exposure on the underlying financing. Most of our interest rate risk is related to non-recourse financings at our businesses.

As of December 31, 2023, the portfolio's pre-tax earnings exposure to a one-time 100-basis-point increase in interest rates for our Argentine peso, Brazilian real, Chilean peso, Colombian peso, Euro, and USD denominated debt would be less than $35 million on interest expense for the debt denominated in these currencies. These amounts represent 2024 full year exposure and do not take into account the historical correlation between these interest rates.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Part A — Report of Independent Registered Public Accounting Firm

Our auditors are Ernst & Young LLP, located in Tysons, Virginia. Their PCAOB ID number is 42.

Part B — Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of The AES Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of The AES Corporation (the Company) as of December 31, 2023, and 2022, the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2023, and the related notes and the financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 26, 2024 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

Critical Audit Matters

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

Long-lived Asset Impairments of Coal and Pet Coke-fired Generation Assets

Description of the Matter

At December 31, 2023, the Company's net property, plant and equipment was $29,958 million. As discussed in Note 1 to the consolidated financial statements, when circumstances indicate that the carrying amount of long-lived assets in a held-for-use asset group may not be recoverable, the Company evaluates the assets for potential impairment. Events or changes in circumstances that may necessitate a recoverability evaluation include, but are not limited to, adverse changes in the regulatory environment, unfavorable changes in power prices or fuel costs, increased competition due to additional capacity in the grid, technological advancements, declining trends in demand, or an expectation it is more likely than not that the asset will be disposed of before the end of its previously estimated useful life. If the carrying amount of the assets exceeds the undiscounted cash flows, an impairment is recognized for the amount by which the carrying amount of the asset group exceeds its fair value. As discussed in Note 22 to the consolidated financial statements, the Company recognized a total asset impairment expense of $471 million related to the Norgener, TEG, TEP, and Warrior Run asset groups, consisting of coal and pet coke generation plants included in the Energy Infrastructure SBU reportable segment in 2023.

Auditing the Company's identification of impairment indicators was complex and highly judgmental because of the many geographic, regulatory, and economic environments in which the Company operates. Also, due to the wide variety of events or changes in circumstances that may indicate that an asset group is not recoverable, auditing the Company's identification of impairment indicators involved a high degree of subjectivity, particularly given the Company's decarbonization initiatives and shift towards clean energy platforms. In addition, auditing the Company's impairment analyses for Norgener, TEG, TEP, and Warrior Run asset groups was complex due to the judgmental nature of the significant assumptions used to determine the fair value of the asset groups (e.g., the Company's projections of revenue growth, discount rates, and consideration of the industry outlook and market conditions).

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company's controls over the identification of impairment indicators and the fair value analysis of the Norgener, TEG, TEP, and Warrior Run asset groups. For example, we tested management's monitoring controls over the evaluation of events or changes in circumstances that would require an asset to be tested for recoverability. We also tested management's review controls of the valuation models used in the impairment analyses, the significant assumptions used to develop the estimates, and the completeness and accuracy of the data used in the valuations.

To test the Company's identification of impairment indicators, our audit procedures included, among others, making inquiries of management, including personnel in operations, to understand changes in the businesses and management's strategic plans, and evaluate whether management has considered any identified changes in their analysis. We evaluated the results of earnings and the projected cash flows for significant coal generation assets and assessed whether there has been a deterioration in earnings or projected losses that would represent an impairment indicator. We also evaluated conditions and trends in the industry for the underlying economies, including any sale or disposition activities, and evaluated any adverse changes in the regulatory environment or the geographic areas to test the completeness and accuracy of the company's evaluation of potential impairment indicators. We also evaluated the Company's useful life estimates, in particular for the coal and pet coke-fired generation assets with impairment indicators, considering the existing Power Purchase Agreements (PPAs) and the market for the use of these assets subsequent to the expiration of existing PPAs, based on the regulatory and market conditions.

To test the impairment analyses for the Norgener, TEG, TEP, and Warrior Run asset groups, our audit procedures included, among others, assessing the appropriateness of valuation methodologies, testing the significant assumptions discussed above, and testing the completeness and accuracy of the underlying data used by the Company in its analyses. We compared the significant assumptions used by management to current industry and economic trends as well as historical results. We performed sensitivity analyses of significant assumptions to evaluate the changes in the fair value of the asset groups that would result from changes in the assumptions. We also involved valuation specialists to assist in our evaluation of the overall valuation methodology and the discount rates used in the fair value estimates, as necessary.

Accounting for the Bellefield and Rexford Renewable Acquisitions

Description of the Matter

During 2023, the Company completed its acquisitions of the Bellefield solar and battery energy storage system (BESS) projects and the Rexford solar and BESS project for consideration of $358 million and $253 million, respectively, as disclosed in Note 25 to the consolidated financial statements. These transactions were accounted for as acquisitions of variable interest entities that did not meet the definition of a business.

Auditing the Company's accounting for its significant renewables acquisitions was complex due to the significant judgment made by management to determine the fair values of significant assets acquired, including project development intangible assets and construction in progress assets. The significant assumptions used included the discount rates and revenue pricing curves used in the Company’s forecasted cash flows to determine the fair value of the acquired assets. In particular, the fair value estimate was sensitive to these significant assumptions, which are affected by expectations about future market conditions.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company’s controls over the accounting for these acquisitions. For example, we tested controls over the recognition and measurement of the consideration transferred and valuation of assets acquired, including management’s review of the valuation models, the significant assumptions used to develop the estimates, and the completeness and accuracy of the data used in the valuations.

To test the estimated fair value of the project development intangible assets and construction in progress, we performed audit procedures that included, among others, evaluating the Company's selection of the valuation methodology, evaluating the methods and significant assumptions used, and evaluating the completeness and accuracy of the underlying data supporting the significant assumptions and estimates. For example, we compared the significant assumptions used by management to third-party industry and market data and to the Company’s budgets and forecasts. We also involved our internal valuation specialists to assist in our evaluation of the reasonableness of the Company’s valuation methodology, forecasted revenue assumptions, and the discount rates used in the valuations.

Allocation of Earnings to Noncontrolling Interests in Tax Equity Partnerships

Description of the Matter

A significant number of renewable projects at AES Clean Energy have been financed with tax equity structures, where the tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes, that vary over the life of the projects. When the allocation of earnings and losses, cash distributions, and tax benefits are not based on fixed ownership percentages, the Company uses the hypothetical liquidation at book value (HLBV) method to calculate the earnings attributable to noncontrolling interest for consolidated partnerships, when it is a reasonable approximation of the profit-sharing arrangement. As discussed in Note 17 to the consolidated financial statements, AES Clean Energy Development and AES Renewable Holdings sold noncontrolling interest to tax equity investors resulting in an increase of $1,163 million to noncontrolling interest in 2023.

Auditing the allocation of earnings to noncontrolling interest holders for tax equity partnerships was complex due to the evaluation of whether a newly established HLBV model used to allocate earnings appropriately reflects the unique substantive profit-sharing terms and features within each arrangement. A greater extent of audit effort and specialized skill and knowledge was required to evaluate compliance with the contractual provisions in each partnership agreement as well as the appropriateness of the investors' capital account balances used in the HLBV models.

How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the controls over the Company's process for developing the HLBV model for new tax equity arrangements. For example, we tested management's review of substantive profit-sharing terms and features to evaluate whether they are properly reflected in the HLBV model for new arrangements. To test the allocation of earnings to noncontrolling interest holders for new significant tax equity partnerships, we read the related partnership agreements to understand the substantive profit-sharing provisions. We evaluated the HLBV models for consistency with the contractual provisions in the related partnership agreements and tested the capital contributions made by the tax equity investors. We involved tax subject matter professionals to assist in evaluating the calculation of the investors' capital accounts used in the HLBV models, including the proceeds attributable to the tax equity investor due to the recognition of investment tax credits and other adjustments as required by the U.S. Internal Revenue Code. Additionally, we tested the allocation of earnings by recalculating the hypothetical liquidation in the HLBV models based on the liquidation provisions of the related partnership agreements.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2008.

Tysons, Virginia

February 26, 2024

Consolidated Balance Sheets

December 31, 2023 and 2022

	2023	2022
	(in millions, except share and per share data)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,426	$ 1,374
Restricted cash	370	536
Short-term investments	395	730
Accounts receivable, net of allowance of $15 and $5, respectively	1,420	1,799
Inventory	712	1,055
Prepaid expenses	177	98
Other current assets, net of allowance of $14 and $2, respectively	1,387	1,533
Current held-for-sale assets	762	518
Total current assets	6,649	7,643
NONCURRENT ASSETS		
Property, Plant and Equipment:		
Land	522	470
Electric generation, distribution assets and other	30,190	26,599
Accumulated depreciation	(8,602)	(8,651)
Construction in progress	7,848	4,621
Property, plant and equipment, net	29,958	23,039
Other Assets:		
Investments in and advances to affiliates	941	952
Debt service reserves and other deposits	194	177
Goodwill	348	362
Other intangible assets, net of accumulated amortization of $498 and $434, respectively	2,243	1,841
Deferred income taxes	396	319
Other noncurrent assets, net of allowance of $9 and $77, respectively	3,259	4,030
Noncurrent held-for-sale assets	811	—
Total other assets	8,192	7,681
TOTAL ASSETS	$ 44,799	$ 38,363
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 2,199	$ 1,730
Accrued interest	315	249
Accrued non-income taxes	278	249
Supplier financing arrangements	974	662
Accrued and other liabilities	1,334	1,489
Recourse debt	200	—
Non-recourse debt, including $1,080 and $416, respectively, related to variable interest entities	3,932	1,758
Current held-for-sale liabilities	499	354
Total current liabilities	9,731	6,491
NONCURRENT LIABILITIES		
Recourse debt	4,264	3,894
Non-recourse debt, including $1,715 and $2,295, respectively, related to variable interest entities	18,482	17,846
Deferred income taxes	1,245	1,139
Other noncurrent liabilities	3,114	3,168
Noncurrent held-for-sale liabilities	514	—
Total noncurrent liabilities	27,619	26,047
Commitments and Contingencies (see Notes 12 and 13)		
Redeemable stock of subsidiaries	1,464	1,321
EQUITY		
THE AES CORPORATION STOCKHOLDERS' EQUITY		
Preferred stock (without par value, 50,000,000 shares authorized; 1,043,050 issued and outstanding at December 31, 2023 and December 31, 2022)	838	838
Common stock ($0.01 par value, 1,200,000,000 shares authorized; 819,051,591 issued and 669,693,234 outstanding at December 31, 2023 and 818,790,001 issued and 668,743,464 outstanding at December 31, 2022)	8	8
Additional paid-in capital	6,355	6,688
Accumulated deficit	(1,386)	(1,635)
Accumulated other comprehensive loss	(1,514)	(1,640)
Treasury stock, at cost (149,358,357 and 150,046,537 shares, respectively)	(1,813)	(1,822)
Total AES Corporation stockholders' equity	2,488	2,437
NONCONTROLLING INTERESTS	3,497	2,067
Total equity	5,985	4,504
TOTAL LIABILITIES AND EQUITY	$ 44,799	$ 38,363

See Accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Operations

Years ended December 31, 2023, 2022, and 2021

	2023	2022	2021
	(in millions, except per share amounts)		
Revenue:			
Non-Regulated	$ 9,245	$ 9,079	$ 8,273
Regulated	3,423	3,538	2,868
Total revenue	12,668	12,617	11,141
Cost of Sales:			
Non-Regulated	(7,173)	(6,907)	(5,982)
Regulated	(2,991)	(3,162)	(2,448)
Total cost of sales	(10,164)	(10,069)	(8,430)
Operating margin	2,504	2,548	2,711
General and administrative expenses	(255)	(207)	(166)
Interest expense	(1,319)	(1,117)	(911)
Interest income	551	389	298
Loss on extinguishment of debt	(63)	(15)	(78)
Other expense	(99)	(68)	(60)
Other income	89	102	410
Gain (loss) on disposal and sale of business interests	134	(9)	(1,683)
Goodwill impairment expense	(12)	(777)	—
Asset impairment expense	(1,067)	(763)	(1,575)
Foreign currency transaction losses	(359)	(77)	(10)
Other non-operating expense	—	(175)	—
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE TAXES AND EQUITY IN EARNINGS OF AFFILIATES	104	(169)	(1,064)
Income tax benefit (expense)	(261)	(265)	133
Net equity in losses of affiliates	(32)	(71)	(24)
LOSS FROM CONTINUING OPERATIONS	(189)	(505)	(955)
Gain from disposal of discontinued businesses, net of income tax benefit (expense) of $7, $0, and $(1), respectively	7	—	4
NET LOSS	(182)	(505)	(951)
Less: Net loss (income) attributable to noncontrolling interests and redeemable stock of subsidiaries	431	(41)	542
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ 249	$ (546)	$ (409)
AMOUNTS ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:			
Income (loss) from continuing operations, net of tax	$ 242	$ (546)	$ (413)
Income from discontinued operations, net of tax	7	—	4
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ 249	$ (546)	$ (409)
BASIC EARNINGS PER SHARE:			
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 0.36	$ (0.82)	$ (0.62)
Income from discontinued operations attributable to The AES Corporation common stockholders, net of tax	0.01	—	0.01
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ 0.37	$ (0.82)	$ (0.61)
DILUTED EARNINGS PER SHARE:			
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 0.34	$ (0.82)	$ (0.62)
Income from discontinued operations attributable to The AES Corporation common stockholders, net of tax	0.01	—	0.01
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ 0.35	$ (0.82)	$ (0.61)

See Accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income (Loss)

Years ended December 31, 2023, 2022, and 2021

	2023	2022	2021
		(in millions)	
NET LOSS	$ (182)	$ (505)	$ (951)
Foreign currency translation activity:			
Foreign currency translation adjustments, net of $0 income tax for all periods	146	(36)	(130)
Reclassification to earnings, net of $0 income tax for all periods	—	—	3
Total foreign currency translation adjustments	146	(36)	(127)
Derivative activity:			
Change in derivative fair value, net of income tax benefit (expense) of $3, $(191), and $1, respectively	(1)	711	5
Reclassification to earnings, net of income tax expense of $9, $9, and $105, respectively	(73)	59	387
Total change in fair value of derivatives	(74)	770	392
Pension activity:			
Change in pension adjustments due to prior service cost, net of $0 income tax for all periods	1	—	—
Change in pension adjustments due to net actuarial gain (loss) for the period, net of income tax expense of $0, $5, and $10, respectively	(4)	13	26
Reclassification to earnings, net of income tax expense of $0, $1, and $3, respectively	—	1	1
Total pension adjustments	(3)	14	27
OTHER COMPREHENSIVE INCOME	69	748	292
COMPREHENSIVE INCOME (LOSS)	(113)	243	(659)
Less: Comprehensive loss (income) attributable to noncontrolling interests and redeemable stock of subsidiaries	498	(127)	438
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ 385	$ 116	$ (221)

See Accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Changes in Equity

Years ended December 31, 2023, 2022, and 2021

	THE AES CORPORATION STOCKHOLDERS									
	Preferred Stock		Common Stock		Treasury Stock		Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss	Noncontrolling Interests [1]
(in millions)	Shares	Amount	Shares	Amount	Shares	Amount				
Balance at December 31, 2020	—	$ —	818.4	$ 8	153.0	$(1,858)	$ 7,561	$ (680)	$ (2,397)	$ 2,086
Net loss	—	—	—	—	—	—	—	(409)	—	(536)
Total foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	—	—	(83)	(44)
Total change in derivative fair value, net of income tax	—	—	—	—	—	—	—	—	247	126
Total pension adjustments, net of income tax	—	—	—	—	—	—	—	—	24	3
Total other comprehensive income	—	—	—	—	—	—	—	—	188	85
Adjustments to redemption value of redeemable stock of subsidiaries [2]	—	—	—	—	—	—	(4)	—	—	—
Disposition of business interests	—	—	—	—	—	—	—	—	—	(132)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	—	(281)
Acquisitions of noncontrolling interests	—	—	—	—	—	—	(9)	—	(11)	(4)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	—	220
Sales to noncontrolling interests			—	—	—	—	(7)	—	—	180
Issuance of preferred shares in subsidiaries	—	—	—	—	—	—	—	—	—	151
Issuance of preferred stock [3]	1.0	838	—	—	—	—	(29)	—	—	—
Dividends declared on common stock ($0.6095/share)	—	—	—	—	—	—	(406)	—	—	—
Issuance and exercise of stock-based compensation benefit plans, net of income tax	—	—	0.3	—	(1.0)	13	—	—	—	—
Balance at December 31, 2021 [3]	1.0	$ 838	818.7	$ 8	152.0	$(1,845)	$ 7,106	$ (1,089)	$ (2,220)	$ 1,769
Net income (loss)	—	—	—	—	—	—	—	(546)	—	128
Total foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	—	—	(37)	1
Total change in derivative fair value, net of income tax	—	—	—	—	—	—	—	—	689	41
Total pension adjustments, net of income tax	—	—	—	—	—	—	—	—	10	4
Total other comprehensive income	—	—	—	—	—	—	—	—	662	46
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	—	(200)
Acquisitions of noncontrolling interests	—	—	—	—	—	—	(78)	—	(80)	(387)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	—	178
Sales to noncontrolling interests	—	—	—	—	—	—	78	—	(2)	473
Issuance of preferred shares in subsidiaries	—	—	—	—	—	—	—	—	—	60
Dividends declared on AES common stock ($0.6399/share)	—	—	—	—	—	—	(428)	—	—	—
Issuance and exercise of stock-based compensation benefit plans, net of income tax	—	—	0.1	—	(2.0)	23	10	—	—	—
Balance at December 31, 2022	1.0	$ 838	818.8	$ 8	150.0	$(1,822)	$ 6,688	$ (1,635)	$ (1,640)	$ 2,067
Net income (loss)	—	—	—	—	—	—	—	249	—	(372)
Total foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	—	—	136	9
Total change in derivative fair value, net of income tax	—	—	—	—	—	—	—	—	3	(77)
Total pension adjustments, net of income tax	—	—	—	—	—	—	—	—	(3)	—
Total other comprehensive income (loss)	—	—	—	—	—	—	—	—	136	(68)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	—	(261)
Acquisitions of noncontrolling interests	—	—	—	—	—	—	24	—	—	(44)
Sales to noncontrolling interests	—	—	—	—	—	—	85	—	(10)	1,754
Issuance of preferred shares in subsidiaries	—	—	—	—	—	—	—	—	—	421
Dividends declared on AES common stock ($0.6702/share)	—	—	—	—	—	—	(449)	—	—	—
Issuance and exercise of stock-based compensation benefit plans, net of income tax	—	—	0.3	—	(0.6)	9	7	—	—	—
Balance at December 31, 2023	1.0	$ 838	819.1	$ 8	149.4	$(1,813)	$ 6,355	$ (1,386)	$ (1,514)	$ 3,497

[1] Excludes redeemable stock of subsidiaries. See Note 16—*Redeemable Stock of Subsidiaries.*
[2] Adjustment to record the redeemable stock of Colon at redemption value.
[3] Includes a $13 million reclass from *Additional paid-in capital* to *Preferred stock* to reflect the retrospective adoption of ASU 2020-06.

See Accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

Years ended December 31, 2023, 2022, and 2021

	2023	2022	2021
		(in millions)	
OPERATING ACTIVITIES:			
Net loss	$ (182)	$ (505)	$ (951)
Adjustments to net loss:			
Depreciation and amortization	1,128	1,053	1,056
Emissions allowance expense	264	425	337
Loss (gain) on realized/unrealized derivatives	143	127	(1)
Gain on remeasurement to acquisition date fair value	—	(5)	(254)
Loss (gain) on disposal and sale of business interests	(134)	9	1,683
Impairment expense	1,079	1,715	1,575
Loss on realized/unrealized foreign currency	331	58	23
Deferred income taxes	(54)	4	(406)
Other	149	123	202
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	161	(532)	(170)
(Increase) decrease in inventory	306	(417)	(93)
(Increase) decrease in prepaid expenses and other current assets	38	(40)	(168)
(Increase) decrease in other assets	5	433	(285)
Increase (decrease) in accounts payable and other current liabilities	(132)	470	(251)
Increase (decrease) in income tax payables, net and other tax payables	(109)	(51)	(271)
Increase (decrease) in deferred income	(2)	33	(314)
Increase (decrease) in other liabilities	43	(185)	190
Net cash provided by operating activities	3,034	2,715	1,902
INVESTING ACTIVITIES:			
Capital expenditures	(7,724)	(4,551)	(2,116)
Acquisitions of business interests, net of cash and restricted cash acquired	(542)	(243)	(658)
Proceeds from the sale of business interests, net of cash and restricted cash sold	254	1	95
Sale of short-term investments	1,318	1,049	616
Purchase of short-term investments	(937)	(1,492)	(519)
Contributions and loans to equity affiliates	(178)	(232)	(427)
Affiliate repayments and returns of capital	5	149	320
Purchase of emissions allowances	(268)	(488)	(265)
Other investing	(116)	(29)	(97)
Net cash used in investing activities	(8,188)	(5,836)	(3,051)
FINANCING ACTIVITIES:			
Borrowings under the revolving credit facilities	7,103	5,424	2,802
Repayments under the revolving credit facilities	(6,285)	(4,687)	(2,420)
Issuance of recourse debt	1,400	200	7
Repayments of recourse debt	(500)	(29)	(26)
Issuance of non-recourse debt	4,521	5,788	1,644
Repayments of non-recourse debt	(2,495)	(3,144)	(2,012)
Payments for financing fees	(142)	(120)	(32)
Purchases under supplier financing arrangements	1,858	1,042	91
Repayments of obligations under supplier financing arrangements	(1,491)	(432)	(35)
Distributions to noncontrolling interests	(323)	(265)	(284)
Acquisitions of noncontrolling interests	(127)	(602)	(117)
Contributions from noncontrolling interests	102	233	365
Sales to noncontrolling interests	1,938	742	173
Issuance of preferred shares in subsidiaries	421	60	153
Issuance of preferred stock	—	—	1,014
Dividends paid on AES common stock	(444)	(422)	(401)
Payments for financed capital expenditures	(10)	(33)	(24)
Other financing	(121)	3	(101)
Net cash provided by financing activities	5,405	3,758	797
Effect of exchange rate changes on cash, cash equivalents and restricted cash	(270)	(56)	(46)
(Increase) decrease in cash, cash equivalents and restricted cash of held-for-sale businesses	(78)	22	55
Total increase (decrease) in cash, cash equivalents and restricted cash	(97)	603	(343)
Cash, cash equivalents and restricted cash, beginning	2,087	1,484	1,827
Cash, cash equivalents and restricted cash, ending	$ 1,990	$ 2,087	$ 1,484

Consolidated Statements of Cash Flows *(continued)*

Years ended December 31, 2023, 2022, and 2021

	2023	2022	2021
		(in millions)	
SUPPLEMENTAL DISCLOSURES:			
Cash payments for interest, net of amounts capitalized	$ 1,317	$ 928	$ 815
Cash payments for income taxes, net of refunds	301	271	459
SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES:			
Initial recognition of contingent consideration for acquisitions (see Note 25)	239	24	9
Noncash recognition of new operating and financing leases (see Note 14)	225	134	56
Dividends declared but not yet paid	116	111	105
Noncash contributions from noncontrolling interests	60	—	—
Noncash contributions to equity affiliates from transfers of tax credits	52	—	—
Notes payable issued for the acquisition of business interests (see Notes 17 and 25)	—	—	258
Noncash consideration transferred for AES Clean Energy acquisitions (see Note 25)	—	—	118

See Accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

1. GENERAL AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The AES Corporation is a holding company (the "Parent Company") that, through its subsidiaries and affiliates, (collectively, "AES" or "the Company") operates a geographically diversified portfolio of electricity generation and distribution businesses. Generally, the liabilities of individual operating entities are non-recourse to the Parent Company and are isolated to the operating entities. Most of our operating entities are structured as limited liability entities, which limit the liability of shareholders. The structure is generally the same regardless of whether a subsidiary is consolidated under a voting or variable interest model. The preparation of these consolidated financial statements is in conformity with accounting principles generally accepted in the United States of America ("U.S. GAAP").

PRINCIPLES OF CONSOLIDATION — The consolidated financial statements of the Company include the accounts of The AES Corporation and its controlled subsidiaries. Furthermore, VIEs in which the Company has an ownership interest and is the primary beneficiary, thus controlling the VIE, have been consolidated. Intercompany transactions and balances are eliminated in consolidation. Investments in entities where the Company has the ability to exercise significant influence, but not control, are accounted for using the equity method of accounting.

NONCONTROLLING INTERESTS — Noncontrolling interests are classified as a separate component of equity in the Consolidated Balance Sheets and Consolidated Statements of Changes in Equity. Additionally, net income and comprehensive income attributable to noncontrolling interests are reflected separately from consolidated net income and comprehensive income on the Consolidated Statements of Operations and Consolidated Statements of Changes in Equity. 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. Losses continue to be attributed to the noncontrolling interests, even when the noncontrolling interests' basis has been reduced to zero.

Equity securities with redemption features that are not solely within the control of the issuer are classified as temporary equity and are included in *Redeemable stock of subsidiaries* on the Consolidated Balance Sheets. Generally, initial measurement will be at fair value. The subsequent allocation of income and dividends is classified in temporary equity. Subsequent measurement and classification vary depending on whether the instrument is probable of becoming redeemable. For those securities that are currently redeemable or where it is probable that the instrument will become redeemable, AES recognizes any changes from the carrying value to redemption value at each reporting period against retained earnings or additional paid-in capital in the absence of retained earnings; such adjustments are classified in temporary equity. When the equity instrument is not probable of becoming redeemable, no adjustment to the carrying value is recognized. Instruments that are mandatorily redeemable are classified as a liability.

EQUITY METHOD INVESTMENTS — Investments in entities over which the Company has the ability to exercise significant influence, but not control, are accounted for using the equity method of accounting and reported in *Investments in and advances to affiliates* on the Consolidated Balance Sheets. The Company's proportionate share of the net income or loss of these companies is included in *Net equity in losses of affiliates* on the Consolidated Statements of Operations.

The Company utilizes the cumulative earnings approach to determine whether distributions received from equity method investees are returns on investment or returns of investment. The Company discontinues the application of the equity method when an investment is reduced to zero and the Company is not otherwise committed to provide further financial support to the investee. The Company resumes the application of the equity method accounting to the extent that net income is greater than the share of net losses not previously recorded.

Upon acquiring the investment, we determine the fair value of the identifiable assets and assumed liabilities and the basis difference between the fair value and the carrying amount of each corresponding asset or liability in the financial statements of the investee. The AES share of the amortization of the basis difference is recognized in *Net equity in losses of affiliates* in the Consolidated Statements of Operations over the life of the asset or liability.

The Company periodically assesses if impairment indicators exist at our equity method investments. When an impairment is observed, any excess of the carrying amount over its estimated fair value is recognized as impairment expense when the loss in value is deemed other-than-temporary and included in *Other non-operating expense* in the Consolidated Statements of Operations.

BUSINESS INTERESTS — Acquisitions and disposals of business interests are generally transactions pertaining to operational legal entities, which may be accounted for as a consolidated business, an asset acquisition, or an equity method investment. Any gains or losses upon the completion of disposals, which include reclassification of cumulative translation adjustments, are recognized in *Gain (loss) on disposal and sale of business interests* in the Consolidated Statements of Operations upon completion of the sale.

ALLOCATION OF EARNINGS — Certain of the Company's businesses are subject to profit-sharing arrangements where the allocation of earnings and losses, cash distributions, and tax benefits are not based on fixed ownership percentages. These arrangements exist for certain U.S. renewable generation partnerships to designate different allocations of value among investors, where the allocations change in form or percentage over the life of the partnership. For these businesses, the Company uses the HLBV method when it is a reasonable approximation of the profit-sharing arrangement. The HLBV method calculates the proceeds that would be attributable to each partner based on the liquidation provisions of the respective operating partnership agreement if the partnership was to be liquidated at book value at the balance sheet date. Each partner’s share of income in the period is equal to the change in the amount of net equity they are legally able to claim based on a hypothetical liquidation of the entity at the end of a reporting period compared to the beginning of that period, adjusted for any capital transactions.

The HLBV method is used both to allocate the equity earnings attributable to AES when the Company accounts for the renewable business as an equity method investment and to calculate the earnings attributable to noncontrolling interest when the business is consolidated by AES. In the early months of operations of a renewable generation facility where HLBV results in a significant decrease in the hypothetical liquidation proceeds attributable to the tax equity investor due to the recognition of ITCs or other adjustments as required by the U.S. Internal Revenue Code, the Company records the impact (sometimes referred to as the ‘Day one gain’) to income in the same period.

USE OF ESTIMATES — U.S. GAAP requires the Company to make estimates and assumptions that affect the asset and liability balances reported as of the date of the consolidated financial statements, as well as the revenues and expenses recognized during the reporting period. Actual results could differ from those estimates. Items subject to such estimates and assumptions include: estimated useful lives of long-lived assets; asset retirement obligations; impairment of goodwill, long-lived assets and equity method investments; valuation allowances for receivables and deferred tax assets; the recoverability of regulatory assets; regulatory liabilities; the fair value of financial instruments; the fair value of assets and liabilities acquired as business combinations or as asset acquisitions by variable interest entities; contingent consideration arising from business combinations or asset acquisitions by variable interest entities; the measurement of equity method investments or noncontrolling interest using the HLBV method for certain renewable generation partnerships; pension liabilities; the incremental borrowing rates used in the determination of lease liabilities; the determination of lease and non-lease components in certain generation contracts; environmental liabilities; temporary equity; and potential litigation claims and settlements.

HELD-FOR-SALE DISPOSAL GROUPS — A disposal group classified as held-for-sale is reflected on the balance sheet at the lower of its carrying amount or estimated fair value less costs to sell. A loss is recognized if the carrying amount of the disposal group exceeds its estimated fair value less costs to sell. If the fair value of the disposal group subsequently exceeds the carrying amount while the disposal group is still held-for-sale, any impairment expense previously recognized will be reversed up to the lesser of the previously recognized expense or the subsequent excess.

Assets and liabilities related to a disposal group classified as held-for-sale are segregated in the balance sheet in the period in which the disposal group is classified as held-for-sale. Assets and liabilities of held-for-sale disposal groups are classified as current when they are expected to be settled or disposed of within twelve months and as noncurrent when they are not expected to be settled or disposed of within the next twelve months. Transactions between the held-for-sale disposal group and businesses that are expected to continue to exist after the disposal are not eliminated to appropriately reflect the continuing operations and balances held-for-sale. See Note 24—*Held-for-Sale and Dispositions* for further information.

DISCONTINUED OPERATIONS — Discontinued operations reporting occurs only when the disposal of a business or a group of businesses represents a strategic shift that has (or will have) a major effect on the

Company's operations and financial results. The Company reports financial results for discontinued operations separately from continuing operations to distinguish the financial impact of disposal transactions from ongoing operations. Prior period amounts in the Consolidated Statements of Operations and Consolidated Balance Sheets are retrospectively revised to reflect the businesses determined to be discontinued operations. The cash flows of businesses that are determined to be discontinued operations are included within the relevant categories within operating, investing and financing activities on the face of the Consolidated Statements of Cash Flows.

Transactions between the businesses determined to be discontinued operations and businesses that are expected to continue to exist after the disposal are not eliminated to appropriately reflect the continuing operations and balances held-for-sale. The results of discontinued operations include any gain or loss recognized on closing or adjustment of the carrying amount to fair value less costs to sell, including gains or losses associated with noncontrolling interests upon completion of the disposal transaction. Adjustments related to components previously reported as discontinued operations under prior accounting guidance are presented as discontinued operations in the current period even if the disposed-of component to which the adjustments are related would not meet the criteria for presentation as a discontinued operation under current guidance.

FAIR VALUE — Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly, hypothetical transaction between market participants at the measurement date, or exit price. The Company applies the fair value measurement accounting guidance to financial assets and liabilities in determining the fair value of investments in marketable debt and equity securities, included in the Consolidated Balance Sheet line items *Short-term investments* and *Other noncurrent assets*; derivative assets, included in *Other current assets* and *Other noncurrent assets*; and, derivative liabilities, included in *Accrued and other liabilities (current)* and *Other noncurrent liabilities*. The Company applies the fair value measurement guidance to nonfinancial assets and liabilities upon the acquisition of a business or assets, or in conjunction with the measurement of an asset retirement obligation or a potential impairment loss on an asset group, equity method investments, or goodwill.

When determining the fair value measurements for assets and liabilities required to be reflected at their fair values, the Company considers the principal or most advantageous market in which it would transact and considers assumptions that market participants would use when pricing the assets or liabilities, such as inherent risk, transfer restrictions and risk of nonperformance. The Company is prohibited from including transaction costs and any adjustments for blockage factors in determining fair value.

In determining fair value measurements, the Company maximizes the use of observable inputs and minimizes the use of unobservable inputs. Assets and liabilities are categorized within a fair value hierarchy based upon the lowest level of input that is significant to the fair value measurement:

- Level 1: Quoted prices in active markets for identical assets or liabilities;
- Level 2: Inputs other than Level 1 that are observable, either directly or indirectly, such as quoted prices in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in markets that are not active or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities; or
- Level 3: Unobservable inputs that are supported by little or no market activity and that are significant to the fair values of the assets or liabilities.

Any transfers between all levels within the fair value hierarchy levels are recognized at the end of the reporting period.

CASH AND CASH EQUIVALENTS — The Company considers unrestricted cash on hand, cash balances not restricted as to withdrawal or usage, deposits in banks, certificates of deposit and short-term marketable securities with original maturities of three months or less to be cash and cash equivalents.

RESTRICTED CASH AND DEBT SERVICE RESERVES — Cash balances restricted as to withdrawal or usage, primarily via contract, are considered restricted cash.

The following table provides a summary of cash, cash equivalents, and restricted cash amounts reported on the Consolidated Balance Sheets that reconcile to the total of such amounts as shown on the Consolidated Statements of Cash Flows (in millions):

	December 31, 2023	December 31, 2022
Cash and cash equivalents	$ 1,426	$ 1,374
Restricted cash	370	536
Debt service reserves and other deposits	194	177
Cash, Cash Equivalents and Restricted Cash	$ 1,990	$ 2,087

INVESTMENTS IN MARKETABLE SECURITIES — The Company's marketable investments are primarily unsecured debentures, certificates of deposit, government debt securities and money market funds.

Short-term investments consist of marketable equity securities and debt securities with original maturities in excess of three months with remaining maturities of less than one year. Marketable debt securities where the Company has both the positive intent and ability to hold to maturity are classified as held-to-maturity and are carried at amortized cost, net of any allowance for credit losses in accordance with ASC 326. Remaining marketable debt securities are classified as available-for-sale or trading and are carried at fair value.

Unrealized gains or losses on available-for-sale debt securities that are not credit-related are reflected in AOCL, a separate component of equity, and the Consolidated Statements of Comprehensive Income (Loss). Any credit-related impairments are recognized as an allowance with a corresponding impact recognized as a credit loss in *Other expense.* Unrealized gains or losses on equity investments are reported in *Other income*. Interest and dividends on investments are reported in *Interest income* and *Other income*, respectively. Gains and losses on sales of investments are determined using the specific identification method.

ACCOUNTS AND NOTES RECEIVABLE AND ALLOWANCE FOR CREDIT LOSSES — Accounts and notes receivable are carried at amortized cost. The Company periodically assesses the collectability of accounts receivable, considering factors such as historical collection experience, the age of accounts receivable and other currently available evidence supporting collectability, and records an allowance for credit losses for the estimated uncollectible amount as appropriate. Credit losses on accounts and notes receivable are generally recognized in *Cost of Sales*. Certain of our businesses charge interest on accounts receivable. Interest income is recognized on an accrual basis. When collection of such interest is not reasonably assured, interest income is recognized as cash is received. Individual accounts and notes receivable are written off when they are no longer deemed collectible.

INVENTORY — Inventory primarily consists of fuel and other raw materials used to generate power, and operational spare parts and supplies used to maintain power generation and distribution facilities. Inventory is carried at lower of cost or net realizable value. Cost is the sum of the purchase price and expenditures incurred to bring the inventory to its existing location. Inventory is primarily valued using the average cost method. Generally, if it is expected fuel inventory will not be recovered through revenue earned from power generation, an impairment is recognized to reflect the fuel at net realizable value. The carrying amount of spare parts and supplies is typically reduced only in instances where the items are considered obsolete.

LONG-LIVED ASSETS — Long-lived assets include property, plant and equipment, assets under finance leases and intangible assets subject to amortization (i.e., finite-lived intangible assets).

Property, plant and equipment — Property, plant and equipment are stated at cost, net of accumulated depreciation. The cost of renewals and improvements that extend the useful life of property, plant and equipment are capitalized.

Construction progress payments, engineering costs, insurance costs, salaries, interest and other costs directly relating to construction in progress are capitalized during the construction period, provided the completion of the construction project is deemed probable, or expensed at the time construction completion is determined to no longer be probable. The continued capitalization of such costs is subject to risks related to successful completion, including those related to government approvals, site identification, financing, construction permitting and contract compliance. Construction-in-progress balances are transferred to electric generation and distribution assets when an asset group is ready for its intended use. Government subsidies, refundable income tax credits that are accounted for as government grants, and liquidated damages recovered for construction delays are recorded as a reduction to property, plant and equipment and reflected in cash flows from investing activities. Maintenance and repairs are charged to expense as incurred.

Depreciation, after consideration of salvage value and asset retirement obligations, is computed using the straight-line method over the estimated useful lives of the assets, which are determined on a composite or component basis. Capital spare parts, including rotable spare parts, are included in electric generation and distribution assets. If the spare part is considered a component, it is depreciated over its useful life after the part is placed in service. If the spare part is deemed part of a composite asset, the part is depreciated over the composite useful life even when being held as a spare part.

Certain of the Company's subsidiaries operate under concession contracts. Certain estimates are utilized to determine depreciation expense for the subsidiaries, including the useful lives of the property, plant and equipment and the amounts to be recovered at the end of the concession contract. The amounts to be recovered under these concession contracts are based on estimates that are inherently uncertain and actual amounts recovered may differ from those estimates. These concession contracts are not within the scope of ASC 853—*Service Concession Arrangements*.

Intangible Assets Subject to Amortization — Finite-lived intangible assets are amortized over their useful lives which range from 1 – 50 years and are included in the Consolidated Balance Sheet line item *Other intangible assets.* The Company accounts for purchased emission allowances as intangible assets and records an expense when they are utilized or sold. Granted emission allowances are valued at zero.

Impairment of Long-lived Assets — When circumstances indicate the carrying amount of long-lived assets in a held-for-use asset group may not be recoverable, the Company evaluates the assets for potential impairment using internal projections of undiscounted cash flows resulting from the use and eventual disposal of the assets. Events or changes in circumstances that may necessitate a recoverability evaluation include, but are not limited to, adverse changes in the regulatory environment, unfavorable changes in power prices or fuel costs, increased competition due to additional capacity in the grid, technological advancements, declining trends in demand, or an expectation it is more likely than not that the asset will be disposed of before the end of its previously estimated useful life. If the carrying amount of the assets exceeds the undiscounted cash flows, an impairment expense is recognized for the amount by which the carrying amount of the asset group exceeds its fair value (subject to the carrying amount not being reduced below fair value for any individual long-lived asset that is determinable without undue cost and effort). An impairment expense for certain assets may be reduced by the establishment of a regulatory asset if recovery through approved rates is probable.

DEBT ISSUANCE COSTS — Costs incurred in connection with the issuance of long-term debt are deferred and presented as a direct reduction from the face amount of that debt and amortized over the related financing period using the effective interest method. Debt issuance costs related to a line-of-credit or revolving credit facility are deferred and presented as an asset and amortized over the related financing period. Make-whole payments in connection with early debt retirements are classified as cash flows used in financing activities.

GOODWILL AND INDEFINITE-LIVED INTANGIBLE ASSETS — The Company evaluates goodwill and indefinite-lived intangible assets for impairment on an annual basis and whenever events or changes in circumstances necessitate an evaluation for impairment. The Company's annual impairment testing date is October 1st.

Goodwill — Goodwill represents the excess of the purchase price of the business acquisition over the fair value of identifiable net assets acquired. Goodwill resulting from an acquisition is assigned to the reporting units that are expected to benefit from the synergies of the acquisition. Generally, each AES business with a goodwill balance constitutes a reporting unit as they are not similar to other businesses in a segment nor are they reported to segment management together with other businesses.

Goodwill is evaluated for impairment either under the qualitative assessment option or the quantitative test option to determine the fair value of the reporting unit. If goodwill is determined to be impaired, an impairment loss measured at the amount by which the reporting unit’s carrying amount exceeds its fair value, not to exceed the carrying amount of goodwill, is recorded.

Indefinite-Lived Intangible Assets — The Company's indefinite-lived intangible assets primarily include land-use rights and transmission rights. Indefinite-lived intangible assets are evaluated for impairment either under the qualitative assessment option or by performing the quantitative impairment test. If the carrying amount of an intangible asset being tested for impairment exceeds its fair value, the excess is recognized as impairment expense.

ACCOUNTS PAYABLE AND OTHER ACCRUED LIABILITIES — Accounts payable consists of amounts due to trade creditors related to the Company's core business operations. These payables include amounts owed to vendors and suppliers for items such as energy purchased for resale, fuel, maintenance, inventory and other raw materials. The remaining balance of other accrued liabilities includes items such as income taxes, regulatory liabilities, legal contingencies, and employee-related costs, including payroll, and benefits.

SUPPLIER FINANCE PROGRAMS — With some purchases, the Company enters into supplier financing arrangements with the goal of securing improved payment terms. The Company confirms supplier invoices to an intermediary financial institution who will pay the supplier directly or reimburse the Company for payments made to the supplier. These arrangements are included in *Supplier financing arrangements* on the Consolidated Balance Sheets in *Current liabilities* as the amounts are all due in less than a year; the related interest expense is recorded on the Consolidated Statements of Operations within *Interest expense*. The company had 28 supplier financing arrangements with a total outstanding balance of $974 million as of December 31, 2023, and 46 supplier financing arrangements with a total outstanding balance of $662 million as of December 31, 2022. The agreements ranged from less than $1 million to $69 million with a weighted average interest rate of 7.51% as of December 31, 2023; as of December 31, 2022, the agreements ranged from less than $1 million to $88 million with a weighted average interest rate of 4.32%. Of the amounts outstanding under supplier financing arrangements, $814 million and $296 million were guaranteed by the Company as of December 31, 2023 and 2022, respectively.

REGULATORY ASSETS AND LIABILITIES — The Company recognizes assets and liabilities that result from regulated ratemaking processes. Regulatory assets generally represent incurred costs which have been deferred due to the probable future recovery via customer rates. Generally, returns earned on regulatory assets are reflected in the Consolidated Statements of Operations within *Interest income*. Regulatory liabilities generally represent obligations to refund customers. Management continually assesses whether regulatory assets are probable of future recovery and regulatory liabilities are probable of future payment by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities, and the status of any pending or potential deregulation legislation. If future recovery of costs previously deferred ceases to be probable, the related regulatory assets are written off and recognized in income from continuing operations.

PENSION AND OTHER POSTRETIREMENT PLANS — The Company recognizes in its Consolidated Balance Sheets an asset or liability reflecting the funded status of pension and other postretirement plans with current-year changes in actuarial gains or losses recognized in AOCL, except for those plans at certain of the Company's regulated utilities that can recover portions of their pension and postretirement obligations through future rates. All plan assets are recorded at fair value. AES follows the measurement date provisions of the accounting guidance, which require a year-end measurement date of plan assets and obligations for all defined benefit plans.

INCOME TAXES — Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax basis. The Company establishes a valuation allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. The Company's tax positions are evaluated under a more likely than not recognition threshold and measurement analysis before they are recognized for financial statement reporting.

Uncertain tax positions have been classified as noncurrent income tax liabilities unless expected to be paid within one year. The Company's policy for interest and penalties related to income tax exposures is to recognize interest and penalties as a component of the provision for income taxes in the Consolidated Statements of Operations.

The Company has elected to treat GILTI as an expense in the period in which the tax is accrued. Accordingly, no deferred tax assets or liabilities are recorded related to GILTI.

The Company applies the flow-through method to account for its investment tax credits.

The Company's accounting policy for releasing the income tax effects from AOCL occurs on a portfolio basis.

The Company has elected an accounting policy not to consider the effects of being subject to the corporate alternative minimum tax in future periods when assessing the realizability of our deferred tax assets, carryforwards, and tax credits. Any effect on the realization of deferred tax assets will be recognized in the period they arise.

Historically, the Company has financed renewables projects with investments from tax equity investors who are allocated certain tax benefits associated with renewable energy projects (e.g. investment tax credits) through partnership agreements. The Inflation Reduction Act allows the owners of renewable energy projects to transfer tax credits directly to third parties. This provides the Company with the flexibility to obtain financing on any particular project with (i) the transfer of tax credits or (ii) investments from tax equity investors who are allocated tax benefits. The Company may also elect to retain the tax credit and use it to reduce its tax liability.

The Company accounts for tax credits that it will retain or transfer as a reduction in income tax expense by either including the expected amount of the tax credit to be claimed or the cash to be received when transferred, respectively, in the calculation of its annual effective tax rate. The estimated tax credits are updated on a quarterly basis, with the year-end calculation including only the tax credits that are associated with projects placed in service, comprising credits claimed or transferred during the year. In assessing realizability for credits to be transferred, the Company includes cash it anticipates receiving in establishing any valuation allowance and establishes a valuation allowance equal to its best estimate of any discount on the transfer. The receipt of cash from the transfer of tax credits is treated as an operating cash inflow.

ASSET RETIREMENT OBLIGATIONS — The Company records the fair value of a liability for a legal obligation to retire an asset in the period in which the obligation is incurred. When a new liability is recognized, the Company capitalizes the costs of the liability by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the obligation, the Company eliminates the liability and, based on the actual cost to retire, may incur a gain or loss.

FOREIGN CURRENCY TRANSLATION — A business's functional currency is the currency of the primary economic environment in which the business operates and is generally the currency in which the business generates and expends cash. Subsidiaries and affiliates whose functional currency is a currency other than the U.S. dollar translate their assets and liabilities into U.S. dollars at the current exchange rates in effect at the end of the fiscal period. Adjustments arising from the translation of the balance sheet of such subsidiaries are included in AOCL. The revenue and expense accounts of such subsidiaries and affiliates are translated into U.S. dollars at the average exchange rates for the period. Gains and losses on intercompany foreign currency transactions that are long-term in nature and which the Company does not intend to settle in the foreseeable future, are also recognized in AOCL. Gains and losses that arise from exchange rate fluctuations on transactions denominated in a currency other than the functional currency are included in determining net income. Accumulated foreign currency translation adjustments are reclassified from AOCL to net income only when realized upon sale or upon complete or substantially complete liquidation of the investment in a foreign entity. The accumulated adjustments are included in carrying amounts in impairment assessments where the Company has committed to a plan that will cause the accumulated adjustments to be reclassified to earnings.

REVENUE RECOGNITION — Revenue is earned from the sale of electricity from our utilities, the production and sale of electricity and capacity from our generation facilities, and development and construction of generation facilities. Revenue is recognized upon the transfer of control of promised goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services. Revenue is recorded net of any taxes assessed on and collected from customers, which are remitted to the governmental authorities.

Utilities — Our utilities sell electricity directly to end-users, such as homes and businesses, and bill customers directly. The majority of our utility contracts have a single performance obligation, as the promises to transfer energy, capacity, and other distribution and/or transmission services are not distinct. Additionally, as the performance obligation is satisfied over time as energy is delivered, and the same method is used to measure progress, the performance obligation meets the criteria to be considered a series. Utility revenue is classified as regulated on the Consolidated Statements of Operations.

In exchange for the right to sell or distribute electricity in a service territory, our utility businesses are subject to government regulation. This regulation sets the framework for the prices (“tariffs”) that our utilities are allowed to charge customers for electricity. Since tariffs are determined by the regulator, the price that our utilities have the right to bill corresponds directly with the value to the customer of the utility's performance completed in each period. The Company also has some month-to-month contracts. Revenue under these contracts is recognized using an output method measured by the MWh delivered each month, which best depicts the transfer of goods or services to the customer, at the approved tariff.

The Company has businesses where it sells and purchases power to and from ISOs and RTOs. Our utility businesses generally purchase power to satisfy the demand of customers that is not contracted through separate PPAs. In these instances, the Company accounts for these transactions on a net hourly basis because the transactions are settled on a net hourly basis. In limited situations, a utility customer may choose to receive generation services from a third-party provider, in which case the Company may serve as a billing agent for the provider and recognize revenue on a net basis.

Generation — Most of our generation fleet sells electricity under contracts to customers such as utilities, industrial users, and corporate clients. Our generation contracts, based on specific facts and circumstances, can have one or more performance obligations as the promise to transfer energy, capacity, and other services may or may not be distinct depending on the nature of the market and terms of the contract.

For contracts determined to have multiple performance obligations, we allocate revenue to each performance obligation based on its relative standalone selling price using a market or expected cost plus margin approach. Additionally, the Company allocates variable consideration to one or more, but not all, distinct goods or services that form part of a single performance obligation when (1) the variable consideration relates specifically to the efforts to transfer the distinct good or service and (2) the variable consideration depicts the amount to which the Company expects to be entitled in exchange for transferring the promised good or service to the customer.

If the contract is determined to contain a performance obligation related to capacity, the performance obligation is generally satisfied over time, and if we use the same method to measure progress, the performance obligations meet the criteria to be considered a series. In measuring progress toward satisfaction of a performance obligation, the Company applies the "right to invoice" practical expedient when available and recognizes revenue in the amount to which the Company has a right to consideration from a customer that corresponds directly with the value of the performance completed to date. Revenue from generation businesses is classified as non-regulated on the Consolidated Statements of Operations.

Energy performance obligations are recognized using an output method, as energy delivered best depicts the transfer of goods or services to the customer. Performance obligations to deliver energy are generally satisfied when the MW is generated. In certain contracts, if plant availability exceeds a contractual target, the Company may receive a performance bonus payment, or if the plant availability falls below a guaranteed minimum target, we may incur a non-availability penalty. Such bonuses or penalties represent a form of variable consideration and are estimated and recognized when it is probable that there will not be a significant reversal.

Certain generation contracts contain operating and sales-type leases where capacity payments are generally considered lease elements. In such cases, the allocation between the lease and non-lease elements is made at the inception of the lease following the guidance in ASC 842.

In assessing whether variable quantities are considered variable consideration or an option to acquire additional goods and services, the Company evaluates the nature of the promise and the legally enforceable rights in the contract. In some contracts, such as requirement contracts, the legally enforceable rights merely give the customer a right to purchase additional goods and services which are distinct. In these contracts, the customer's action results in a new obligation, and the variable quantities are considered an option.

When energy or capacity is sold or purchased in the spot market or to ISOs, the Company assesses the facts and circumstances to determine gross versus net presentation of spot revenues and purchases. Generally, the nature of the performance obligation is to sell surplus energy or capacity above contractual commitments, or to purchase energy or capacity to satisfy deficits. Generally, on an hourly basis, a generator is either a net seller or a net buyer in terms of the amount of energy or capacity transacted with the ISO. In these situations, the Company recognizes revenue for the hours where the generator is a net seller and cost of sales for the hours where the generator is a net buyer.

The transaction price allocated to a construction performance obligation is recognized as revenue over time as construction activity occurs, with revenue being fully recognized upon completion of construction. These contracts may include a difference in timing between revenue recognition and the collection of cash receipts, which may be collected over the term of the entire arrangement. The timing difference could result in a significant financing component for the construction performance obligation if determined to be a material component of the transaction price. The Company accounts for a significant financing component under the effective interest rate method, recognizing a long-term receivable for the expected future payments related to the construction performance obligation in the *Other noncurrent assets* line item on the Consolidated Balance Sheets. As payments are collected from the customer over the term of the contract, consideration related to the construction performance obligation is bifurcated between the principal repayment of the long-term receivable and the related interest income, recognized in the Consolidated Statements of Operations.

Contract Balances — The timing of revenue recognition, billings, and cash collections results in accounts receivable and contract liabilities. Accounts receivable represent unconditional rights to consideration and consist of both billed amounts and unbilled amounts typically resulting from sales under long-term contracts when revenue recognized exceeds the amount billed to the customer. We bill both generation and utilities customers on a contractually agreed-upon schedule, typically at periodic intervals (e.g., monthly). The calculation of revenue earned but not yet billed is based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month.

Our contract liabilities consist of deferred revenue which is classified as current or noncurrent based on the timing of when we expect to recognize revenue. The current portion of our contract liabilities is reported in *Accrued and other liabilities* and the noncurrent portion is reported in *Other noncurrent liabilities* on the Consolidated Balance Sheets.

Remaining Performance Obligations — The transaction price allocated to remaining performance obligations represents future consideration for unsatisfied (or partially unsatisfied) performance obligations at the end of the reporting period. The Company has elected to apply the optional disclosure exemptions under ASC 606. Therefore, the amount disclosed in Note 20—*Revenue* excludes contracts with an original length of one year or less, contracts for which we recognize revenue based on the amount we have the right to invoice for services performed, and variable consideration allocated entirely to a wholly unsatisfied performance obligation when the consideration relates specifically to our efforts to satisfy the performance obligation and depicts the amount to which we expect to be entitled. As such, consideration for energy is excluded from the amount disclosed as the variable consideration relates to the amount of energy delivered and reflects the value the Company expects to receive for the energy transferred. Estimates of revenue expected to be recognized in future periods also exclude unexercised customer options to purchase additional goods or services that do not represent material rights to the customer.

LEASES — The Company has operating and finance leases for energy production facilities, land, office space, transmission lines, vehicles and other operating equipment in which the Company is the lessee. Operating leases with an initial term of 12 months or less are not recorded on the balance sheet, but are expensed on a straight-line basis over the lease term. The Company's leases do not contain any material residual value guarantees, restrictive covenants or subleases.

Right-of-use assets represent our right to use an underlying asset for the lease term while lease liabilities represent our obligation to make lease payments arising from the lease. Right-of-use assets and lease liabilities are recognized on commencement of the lease based on the present value of lease payments over the lease term. Generally, the rate implicit in the lease is not readily determinable; as such, we use the subsidiaries' incremental borrowing rate based on the information available at commencement in determining the present value of lease payments. The right-of-use asset also includes any lease payments made and excludes lease incentives that are paid or payable to the lessee at commencement. The lease term includes the option to extend or terminate the lease if it is reasonably certain that the option will be exercised.

The Company has operating leases for certain generation contracts that contain provisions to provide capacity to a customer, which is a stand-ready obligation to deliver energy when required by the customer in which the Company is the lessor. Capacity payments are generally considered lease elements as they cover the majority of available output from a facility. The allocation of contract payments between the lease and non-lease elements is made at the inception of the lease. Fixed lease payments from such contracts are recognized as lease revenue on a straight-line basis over the lease term, whereas variable lease payments are recognized when earned.

The Company has sales-type leases for BESS in which the Company is the lessor. These arrangements allow customers the ability to determine when to charge and discharge the BESS, representing the transfer of control and constitutes the arrangement as a sales-type lease. Upon commencement of the lease, the book value of the leased asset is removed from the balance sheet and a net investment in sales-type lease is recognized based on the present value of fixed payments under the contract and the residual value of the underlying asset.

SHARE-BASED COMPENSATION — The Company grants share-based compensation in the form of restricted stock units, performance stock units, performance cash units, and stock options. The expense is based on the grant-date fair value of the equity or liability instrument issued and is recognized on a straight-line basis over the requisite service period, net of estimated forfeitures. The Company uses a Black-Scholes option pricing model to estimate the fair value of stock options granted to its employees.

GENERAL AND ADMINISTRATIVE EXPENSES — General and administrative expenses include corporate and other expenses related to corporate staff functions and initiatives, primarily executive management, finance, legal, human resources, and information systems, which are not directly allocable to our business segments. Additionally, all costs associated with corporate business development efforts are classified as general and administrative expenses.

DERIVATIVES AND HEDGING ACTIVITIES — Under the accounting standards for derivatives and hedging, the Company recognizes all contracts that meet the definition of a derivative, except those designated as normal purchase or normal sale at inception, as either assets or liabilities in the Consolidated Balance Sheets and measures those instruments at fair value. See Note 5—*Fair Value* and *Fair value* in this section for additional discussion regarding the determination of fair value.

PPAs and fuel supply agreements are evaluated to assess if they either meet the definition of a derivative or contain an embedded derivative requiring separate valuation and accounting. When available, the Company elects the normal purchase normal sale scope exception for these contracts.

The Company typically designates its derivative instruments as cash flow hedges if they meet the criteria specified in ASC 815, *Derivatives and Hedging*. The Company enters into interest rate swap agreements in order to hedge the variability of expected future cash interest payments. Foreign currency derivative contracts are primarily used to reduce risks arising from variability in forecasted cash flows denominated in non-functional currencies. The objective of these contracts is to minimize the impact of foreign currency fluctuations on operating results. The Company also enters into commodity futures, swaps and options to hedge price variability inherent in forecasted purchases and sales of electricity, fuels, and other commodities. The objectives of the commodity contracts are to minimize the impact of variability in spot commodity prices and stabilize estimated revenue and expense streams. The Company does not use derivative instruments for speculative purposes.

For our cash flow hedges, changes in fair value are deferred in AOCL and are recognized into earnings as the hedged transactions affect earnings. If a derivative is no longer highly effective, hedge accounting will be discontinued prospectively. For cash flow hedges of forecasted transactions, AES estimates the future cash flows of the forecasted transactions and evaluates the probability of the occurrence and timing of such transactions.

Changes in the fair value of derivatives not designated and qualifying as accounting hedges are immediately recognized in earnings. Regardless of when gains or losses on derivatives are recognized in earnings, they are generally classified as interest expense for interest rate and cross-currency derivatives, foreign currency transaction gains or losses for foreign currency derivatives, and non-regulated revenue or non-regulated cost of sales for commodity and other derivatives. Cash flows arising from derivatives are included in the Consolidated Statements of Cash Flows as an operating activity given the nature of the underlying risk being economically hedged and the lack of significant financing elements, except that cash flows on designated and qualifying hedges of variable-rate interest during construction are classified as an investing activity. Cash payments and receipts to terminate interest rate derivatives prior to the end of their effective date are classified as an operating activity however they are excluded from the *Cash payments for interest, net of amounts capitalized* supplementary disclosure on the Consolidated Statements of Cash Flows. These cash receipts (payments) totaled $181 million, $239 million, and $(6) million for the years ended December 31, 2023, 2022, and 2021, respectively. The Company has elected not to offset net derivative positions in the financial statements.

CREDIT LOSSES — In accordance with ASC 326, the Company records an allowance for CECL for accounts and notes receivable, financing receivables, contract assets, net investments in leases recognized as a lessor, held-to-maturity debt securities, financial guarantees related to the non-payment of a financial obligation, and off-balance sheet credit exposures not accounted for as insurance. The CECL allowance is based on the asset's amortized cost and reflects management's expected risk of credit losses over the remaining contractual life of the asset. CECL allowances are estimated using relevant information about the collectibility of cash flows and consider information about past events, current conditions, and reasonable and supportable forecasts of future economic conditions.

The following table represents the rollforward of the allowance for credit losses for the periods indicated (in millions):

Twelve Months Ended December 31, 2023	Accounts Receivable	Mong Duong Loan Receivable	Argentina Receivables[2]	Lease Receivable [3]	Other	Total
CECL reserve balance at beginning of period	$ 3	$ 28	$ 30	$ 20	$ 2	$ 83
Current period provision	23	—	—	—	17	40
Write-offs charged against allowance	(15)	—	—	(20)	—	(35)
Recoveries collected	2	(3)	—	—	—	(1)
Foreign exchange	2	—	(23)	—	(2)	(23)
CECL reserve balance at end of period	$ 15	$ 25	$ 7	$ —	$ 17	$ 64

Twelve Months Ended December 31, 2022	Accounts Receivable [1]	Mong Duong Loan Receivable	Argentina Receivables	Lease Receivable	Other	Total
CECL reserve balance at beginning of period	$ 9	$ 30	$ 23	$ —	$ 1	$ 63
Current period provision	10	—	22	20	1	53
Write-offs charged against allowance	(19)	—	—	—	—	(19)
Recoveries collected	3	(2)	(1)	—	—	—
Foreign exchange	—	—	(14)	—	—	(14)
CECL reserve balance at end of period	$ 3	$ 28	$ 30	$ 20	$ 2	$ 83

(1) Excludes operating lease receivable allowances and contractual dispute allowances of $1 million as of December 31, 2022. Those reserves are not in scope under ASC 326.

(2) Increase in CECL reserve balance for regulatory receivables in Argentina.

(3) Lease receivable credit losses allowance at Southland Energy (AES Gilbert).

NEW ACCOUNTING PRONOUNCEMENTS — The following table provides a brief description of recent accounting pronouncements that had an impact on the Company's consolidated financial statements. Accounting pronouncements not listed below were assessed and determined to be either not applicable or did not have a material impact on the Company's consolidated financial statements.

New Accounting Standards Adopted			
ASU Number and Name	**Description**	**Date of Adoption**	**Effect on the financial statements upon adoption**
2021-08, Business Combinations (Topic 805): Accounting for Contract Assets and Contract Liabilities from Contracts with Customers	This update is to improve the accounting for acquired revenue contracts with customers in a business combination by addressing diversity in practice and inconsistency related to the following: (1) recognition of an acquired contract liability, and (2) payment terms and their effect on subsequent revenue recognized by the acquirer. Early adoption of the amendments is permitted, including adoption in an interim period. An entity that early adopts in an interim period should apply the amendments (1) retrospectively to all business combinations for which the acquisition date occurs on or after the beginning of the fiscal year that includes the interim period of early application and (2) prospectively to all business combinations that occur on or after the date of initial application.	January 1, 2023	The Company adopted this standard on a prospective basis, which is being applied to any business combinations that occur in 2023 or after. The adoption of this ASU did not have a material impact on the Company's consolidated financial statements.
2022-02 Financial Instruments - Credit Losses (Topic 326): Troubled Debt Restructurings and Vintage Disclosures	ASU 2022-02 amends ASC 326-20-50-6 to require public business entities to disclose gross write-offs recorded in the current period, on a year-to-date basis, by year of origination in the vintage disclosures. This disclosure should cover each of the previous five annual periods starting with the date of the financial statements and, for the annual periods before that, an aggregate total. However, upon adoption of the ASU, an entity would not provide the previous five annual periods of gross write-offs. The FASB decided that disclosure of gross write-offs would instead be applied on a prospective transition basis so that preparers can "build" the five-annual-period disclosure over time.	January 1, 2023	The Company adopted this standard on a prospective basis and it did not have a material impact on the Company's consolidated financial statements.

2022-04,Liabilities - Supplier Finance Programs (Topic 450-50): Disclosure of Supplier Finance Program Obligations	This update is to provide additional information and disclosures about an entity's use of supplier finance programs to see how these programs will affect an entity's working capital, liquidity, and cash flows. Entities that use supplier finance programs as the buyer party should disclose (1) the key terms of the payment terms and assets pledged as security or other forms of guarantees provided and (2) the unpaid amount outstanding, a description of where those obligations are presented on the balance sheet, and a rollforward of those obligations during the annual period.	January 1, 2023, except for the rollforward information, which is effective for fiscal years beginning after December 15, 2023.	The ASU only requires disclosures related to the Company's supplier finance programs and does not affect the recognition, measurement, or presentation of supplier finance program obligations on the balance sheet or cash flow statement. The Company adopted the new disclosure requirements in the first quarter of 2023, except for the annual requirement to disclose rollforward information, which the Company expects to adopt and present prospectively beginning in the 2024 annual financial statements.
2023-03, Presentation of Financial Statements (Topic 205), Income Statement - Reporting Comprehensive Income (Topic 220), Distinguishing Liabilities from Equity (Topic 480), Equity (Topic 505), and Compensation - Stock Compensation (Topic 718)	This Accounting Standards Update amends various SEC paragraphs pursuant to SEC Staff Accounting Bulletin No. 120, SEC Staff Announcement at the March 24, 2022 EITF Meeting, and Staff Accounting Bulletin Topic 6.B, Accounting Series Release 280—General Revision of Regulation S-X: Income or Loss Applicable to Common Stock. The amendments in this Update are effective for all entities upon issuance of this Update.	June 30, 2023	The adoption of this ASU did not have a material impact on the Company's consolidated financial statements.

New Accounting Pronouncements Issued But Not Yet Effective — The following table provides a brief description of recent accounting pronouncements that could have a material impact on the Company's consolidated financial statements once adopted. Accounting pronouncements not listed below were assessed and determined to be either not applicable or are expected to have no material impact on the Company's consolidated financial statements.

New Accounting Standards Issued But Not Yet Effective			
ASU Number and Name	Description	Date of Adoption	Effect on the financial statements upon adoption
2023-06 Disclosure Improvements: Codification Amendments in Response to the SEC's Disclosure Update and Simplification Initiative	In U.S. Securities and Exchange Commission (SEC) Release No. 33-10532, Disclosure Update and Simplification, issued August 17, 2018, the SEC referred certain of its disclosure requirements that overlap with, but require incremental information to, generally accepted accounting principles (GAAP) to the FASB for potential incorporation into the Codification. The amendments in this Update are the result of the Board's decision to incorporate into the Codification 14 of the 27 disclosures referred by the SEC. The amendments in this Update represent changes to clarify or improve disclosure and presentation requirements of a variety of Topics. Many of the amendments allow users to more easily compare entities subject to the SEC's existing disclosures with those entities that were not previously subject to the SEC's requirements. Also, the amendments align the requirements in the Codification with the SEC's regulations.	The effective date for each amendment will be the date on which the SEC's removal of that related disclosure becomes effective, with early adoption prohibited. The amendments in this Update should be applied prospectively.	The Company will provide the required disclosures on a prospective basis on the date each amendment becomes effective. The Company does not expect ASU 2023-06 will have any impact to our consolidated financial statements.
2023-07 Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures	The amendments in this section are designed to improve the disclosures related to Segment reporting on an interim and annual basis. Public companies must disclose significant segment expenses and an amount for other segment items. This will also require that a company disclose its annual disclosures under Topic 280 in each interim period. Furthermore, companies will need to disclose the Chief Operating Decision Maker (CODM) and how the CODM assesses the performance of a segment. Lastly, public companies that have a single reportable segment must report the required disclosures under topic 280.	The amendments in this Update are effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024. Early adoption is permitted.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.
2023-09 Income Taxes (Topic 740): Improvements to Income Tax Disclosures	The amendments in this Update require that public business entities on an annual basis (1) disclose specific categories in the rate reconciliation and (2) provide additional information for reconciling items that meet a quantitative threshold. Furthermore, companies are required to disclose a disaggregated amount of income taxes paid at a federal, state, and foreign level as well as a break down of income taxes paid in an jurisdiction that comprises 5% of a company's total income taxes paid. Lastly, this ASU requires that companies disclose income (loss) from continuing operations before income tax at a domestic and foreign level and that companies disclose income tax expense from continuing operations on a federal, state, and foreign level.	The amendments in this Update are effective for fiscal years beginning after December 15, 2024	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.

2. INVENTORY

Inventory is valued primarily using the average-cost method. The following table summarizes the Company's inventory balances as of the dates indicated (in millions):

December 31,	2023	2022
Fuel and other raw materials	$ 424	$ 733
Spare parts and supplies	288	322
Total	$ 712	$ 1,055

3. PROPERTY, PLANT AND EQUIPMENT

The following table summarizes the components of the electric generation, distribution, and other property, plant and equipment (in millions) with their estimated useful lives (in years). The amounts are stated net of all prior asset impairment losses recognized.

	Estimated Useful Life (in years)	December 31, 2023	December 31, 2022
Electric generation and distribution facilities	5-40	$ 27,517	$ 24,135
Other buildings	3-51	1,239	1,197
Furniture, fixtures and equipment	3-30	397	348
Other	1-39	1,037	919
Total electric generation, distribution assets and other		30,190	26,599
Accumulated depreciation		(8,602)	(8,651)
Net electric generation, distribution assets and other		$ 21,588	$ 17,948

The following table summarizes depreciation expense (including the amortization of assets recorded under finance leases and the amortization of asset retirement obligations) and interest capitalized during development and construction on qualifying assets for the periods indicated (in millions):

Years Ended December 31,	2023	2022	2021
Depreciation expense	$ 1,045	$ 982	$ 972
Interest capitalized during development and construction	563	224	226

Property, plant and equipment, net of accumulated depreciation, of $9.5 billion and $8.9 billion was mortgaged, pledged or subject to liens as of December 31, 2023 and 2022, respectively, including assets classified as held-for-sale.

The following table summarizes non-regulated and regulated electric generation, distribution, and other property, plant and equipment and accumulated depreciation as of the dates indicated (in millions):

December 31,	2023	2022
Non-regulated electric generation assets and other, gross	$ 20,195	$ 16,890
Non-regulated accumulated depreciation	(4,777)	(4,584)
Non-regulated electric generation assets and other, net	15,418	12,306
Regulated electric generation, distribution assets and other, gross	9,995	9,709
Regulated accumulated depreciation	(3,825)	(4,067)
Regulated electric generation, distribution assets and other, net	6,170	5,642
Net electric generation, distribution assets and other	$ 21,588	$ 17,948

4. ASSET RETIREMENT OBLIGATIONS

The following table presents amounts recognized related to asset retirement obligations for the periods indicated (in millions):

	2023	2022
Balance at January 1	$ 757	$ 606
Additional liabilities incurred	40	97
Liabilities assumed in acquisition	—	15
Liabilities settled	(14)	(29)
Accretion expense	31	30
Change in estimated cash flows	(35)	35
Other	(1)	3
Balance at December 31	$ 778	$ 757

The Company's asset retirement obligations include active ash landfills, water treatment basins, and the removal or dismantlement of certain plants and equipment. The Company uses the cost approach to determine the initial value of ARO liabilities, which is estimated by discounting expected cash outflows to their present value using market-based rates at the initial recording of the liabilities. Cash outflows are based on the approximate future disposal costs as determined by market information, historical information or other management estimates. Subsequent downward revisions of ARO liabilities are discounted using the market-based rates that existed when the liability was initially recognized. These inputs to the fair value of the ARO liabilities are considered Level 3 inputs under the fair value hierarchy.

During the year ended December 31, 2023, the Company increased the asset retirement obligations and corresponding assets at AES Clean Energy and AES Indiana by $43 million and $34 million, respectively. This was offset by decreases at Southland Energy and AES Brasil of $51 million and $20 million, respectively. The increase at AES Clean Energy is mostly due to an upward revision of estimated cash flows as a result of a decommissioning study done in the fourth quarter of 2023, which mostly impacted the estimated cash flows related to solar assets.

The increase at AES Indiana is mostly due to additional liabilities incurred due to revised remediation plans for ash ponds at Eagle Valley and AES Indiana's solar projects. The decrease at Southland Energy is mostly due to a downward revision of estimated cash flows as a result of revised quotes from vendors for the demolition of the Southland legacy units. The decrease at AES Brasil is mostly due to a downward revision of estimated cash flows at the Mandacaru, Salinas, and Cubico II wind complexes and AES Brasil solar facilities.

During the year ended December 31, 2022, the Company increased the asset retirement obligations and corresponding assets at Southland Energy, AES Clean Energy, AES Indiana, and AES Brasil by $75 million, $27 million, $27 million, and $16 million, respectively. The increase at Southland Energy is mostly due to additional liabilities incurred related to a demolition obligation at Alamitos. The increase at AES Clean Energy is mostly due to additional liabilities incurred as a result of new development projects. The increase at AES Indiana is primarily due to an upward revision of estimated cash flows at the Petersburg, Eagle Valley, and Harding Street plants. The increase at AES Brasil is primarily due to the initial recognition of asset retirement obligations as a result of the Cubico II acquisition.

5. FAIR VALUE

The fair value of current financial assets and liabilities, debt service reserves, and other deposits approximate their reported carrying amounts. The estimated fair values of the Company's assets and liabilities have been determined using available market information. Because these amounts are estimates and based on hypothetical transactions to sell assets or transfer liabilities, the use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts.

Valuation Techniques — The fair value measurement accounting guidance describes three main approaches to measuring the fair value of assets and liabilities: (1) market approach, (2) income approach, and (3) cost approach. The market approach uses prices and other relevant information generated from market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to convert future amounts to a single present value amount. The measurement is based on current market expectations of the return on those future amounts. The cost approach is based on the amount that would currently be required to replace an asset. The Company measures its investments and derivatives at fair value on a recurring basis. Additionally, in connection with annual or event-driven impairment evaluations, certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis. These include long-lived tangible assets (i.e., property, plant and equipment), goodwill, and intangible assets (e.g., sales concessions, land use rights and water rights, etc.). In general, the Company determines the fair value of investments and derivatives using the market approach and the income approach, respectively. In the nonrecurring measurements of nonfinancial assets and liabilities, all three approaches are considered; however, the value estimated under the income approach is often the most representative of fair value.

Investments — The Company's investments measured at fair value generally consist of marketable debt and equity securities. Equity securities are either measured at fair value using quoted market prices or based on comparisons to market data obtained for similar assets. Debt securities primarily consist of unsecured debentures and certificates of deposit held by our Brazilian subsidiaries. Returns and pricing on these instruments are generally indexed to the market interest rates in Brazil. Debt securities are measured at fair value based on comparisons to market data obtained for similar assets.

Derivatives — Derivatives are measured at fair value using quoted market prices or the income approach utilizing spot and forward benchmark interest rates, foreign exchange rates, commodity prices, volatilities and credit data, as applicable. When significant inputs are not observable, the Company uses relevant techniques to determine the inputs, such as regression analysis or prices for similarly traded instruments available in the market.

The Company's methodology to fair value its derivatives is to start with any observable inputs; however, in certain instances the published forward rates or prices may not extend through the remaining term of the contract, and management must make assumptions to extrapolate the curve, which necessitates the use of unobservable inputs, such as proxy commodity prices or historical settlements to forecast forward prices. With respect to credit inputs, in certain instances the spread that reflects the credit or nonperformance risk is unobservable, requiring the use of proxy yield curves of similar credit quality.

To determine the fair value of a derivative, cash flows are discounted using the relevant spot benchmark interest rate. The Company then makes a credit valuation adjustment ("CVA"), as applicable, by further discounting the cash flows for nonperformance or credit risk based on the observable or estimated debt spread of the Company's subsidiary or its counterparty and the tenor of the respective derivative instrument. The CVA for potential future scenarios in which the derivative is in an asset position is based on the counterparty's credit ratings, credit default swap spreads, and debt spreads, as available. The CVA for potential future scenarios in which the derivative is in a liability position is based on the Parent Company's or the subsidiary's current debt spread. In the absence of readily obtainable credit information, the Parent Company's or the subsidiary's estimated credit rating and spreads of comparably rated entities or the respective country's debt spreads are used as a proxy. All derivative instruments are analyzed individually and are subject to unique risk exposures.

The fair value hierarchy of an asset or a liability is based on the level of significance of the input assumptions. An input assumption is considered significant if it affects the fair value by at least 10%. Assets and liabilities are classified as Level 3 when the use of unobservable inputs is significant. When the use of unobservable inputs is insignificant, assets and liabilities are classified as Level 2. Transfers between Level 3 and Level 2 result from changes in significance of unobservable inputs used to calculate the CVA.

Debt — Recourse and non-recourse debt are carried at amortized cost. The fair value of recourse debt is estimated based on quoted market prices. The fair value of non-recourse debt is estimated based upon interest rates and other features of the loan. In general, the carrying amount of variable rate debt is a close approximation of its fair value. For fixed rate loans, the fair value is estimated using quoted market prices or discounted cash flow ("DCF") analyses. The fair value of recourse and non-recourse debt excludes accrued interest at the valuation date. The fair value was determined using available market information as of December 31, 2023. The Company is not aware of any factors that would significantly affect the fair value amounts subsequent to December 31, 2023.

Nonrecurring measurements — For nonrecurring measurements derived using the income approach, fair value is generally determined using valuation models based on the principles of DCF. The income approach is most often used in the impairment evaluation of long-lived tangible assets, equity method investments, goodwill, and intangible assets. Where the use of market observable data is limited or not available for certain input assumptions, the Company develops its own estimates using a variety of techniques such as regression analysis and extrapolations. Depending on the complexity of a valuation, an independent valuation firm may be engaged to assist management in the valuation process.

For nonrecurring measurements derived using the market approach, recent market transactions involving the sale of identical or similar assets are considered. The use of this approach is limited because it is often difficult to identify sale transactions of identical or similar assets. This approach is used in impairment evaluations of certain intangible assets. Otherwise, it is used to corroborate the fair value determined under the income approach.

For nonrecurring measurements derived using the cost approach, fair value is typically based upon a replacement cost approach. This approach involves a considerable amount of judgment, which is why its use is limited to the measurement of long-lived tangible assets. Like the market approach, this approach is also used to corroborate the fair value determined under the income approach.

Fair Value Considerations — In determining fair value, the Company considers the source of observable market data inputs, liquidity of the instrument, the credit risk of the counterparty, and the risk of the Company's or its counterparty's nonperformance. The conditions and criteria used to assess these factors are:

Sources of market assumptions — The Company derives most of its market assumptions from market efficient data sources (e.g., Bloomberg and Reuters). To determine fair value where market data is not readily available, management uses comparable market sources and empirical evidence to develop its own estimates of market assumptions.

Market liquidity — The Company evaluates market liquidity based on whether the financial or physical instrument, or the underlying asset, is traded in an active or inactive market. An active market exists if the prices are fully transparent to market participants, can be measured by market bid and ask quotes, the market has a relatively large proportion of trading volume as compared to the Company's current trading volume, and the market has a significant number of market participants that will allow the market to rapidly absorb the quantity of assets traded without significantly affecting the market price. Another factor the Company considers when determining whether a market is active or inactive is the presence of government or regulatory controls over pricing that could make it difficult to establish a market-based price when entering into a transaction.

Nonperformance risk — Nonperformance risk refers to the risk that an obligation will not be fulfilled and affects the value at which a liability is transferred or an asset is sold. Nonperformance risk includes, but may not be limited to, the Company's or its counterparty's credit and settlement risk. Nonperformance risk adjustments are dependent on credit spreads, letters of credit, collateral, other arrangements available, and the nature of master netting arrangements. The Company is party to various interest rate swaps and options, foreign currency options and forwards, and derivatives and embedded derivatives, which subject the Company to nonperformance risk. The financial and physical instruments held at the subsidiary level are generally non-recourse to the Parent Company.

Nonperformance risk on the investments held by the Company is incorporated in the fair value derived from quoted market data to mark the investments to fair value.

Recurring Measurements — The following table presents, by level within the fair value hierarchy as described in Note 1—*General and Summary of Significant Accounting Policies,* the Company's financial assets and liabilities that were measured at fair value on a recurring basis as of the dates indicated (in millions). For the Company's investments in marketable debt securities, the security classes presented were determined based on the nature and risk of the security and are consistent with how the Company manages, monitors, and measures its marketable securities:

	December 31, 2023				December 31, 2022			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
DEBT SECURITIES:								
Available-for-sale:								
Certificates of deposit	$ —	$ 360	$ —	$ 360	$ —	$ 698	$ —	$ 698
Government debt securities	—	—	—	—	—	3	—	3
Total debt securities	—	360	—	360	—	701	—	701
EQUITY SECURITIES:								
Mutual funds	46	—	—	46	38	—	—	38
Total equity securities	46	—	—	46	38	—	—	38
DERIVATIVES:								
Interest rate derivatives	—	182	2	184	—	314	—	314
Foreign currency derivatives	—	15	59	74	—	22	64	86
Commodity derivatives	—	127	1	128	—	232	13	245
Total derivatives — assets	—	324	62	386	—	568	77	645
TOTAL ASSETS	$ 46	$ 684	$ 62	$ 792	$ 38	$ 1,269	$ 77	$ 1,384
Liabilities								
Contingent consideration	$ —	$ —	$ 165	$ 165	$ —	$ —	$ 48	$ 48
DERIVATIVES:								
Interest rate derivatives	—	102	6	108	—	6	—	6
Cross-currency derivatives	—	63	—	63	—	42	—	42
Foreign currency derivatives	—	19	—	19	—	20	—	20
Commodity derivatives	—	145	111	256	—	346	60	406
Total derivatives — liabilities	—	329	117	446	—	414	60	474
TOTAL LIABILITIES	$ —	$ 329	$ 282	$ 611	$ —	$ 414	$ 108	$ 522

As of December 31, 2023, all available-for-sale debt securities had stated maturities within one year. For the years ended December 31, 2023 and 2022, no impairments of marketable securities were recognized in earnings or other comprehensive income (loss). Gains and losses on the sale of investments are determined using the specific-identification method. The following table presents gross proceeds from sale of available-for-sale securities for the periods indicated (in millions):

Year Ended December 31,	2023	2022	2021
Gross proceeds from sale of available-for-sale securities	$ 1,377	$ 1,065	$ 578

The following tables present a reconciliation of net derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the years ended December 31, 2023 and 2022 (presented net by type of derivative in millions). Transfers between Level 3 and Level 2 principally result from changes in the significance of unobservable inputs used to calculate the credit valuation adjustment.

Year Ended December 31, 2023	Derivative Assets and Liabilities				
	Interest Rate	Foreign Currency	Commodity	Contingent Consideration	Total
Balance at January 1	$ —	$ 64	$ (47)	$ (48)	$ (31)
Total realized and unrealized gains (losses):					
Included in earnings	—	16	(10)	14	20
Included in other comprehensive income — derivative activity	1	6	(48)	—	(41)
Included in regulatory (assets) liabilities	—	—	(1)	—	(1)
Acquisitions	—	—	—	(239)	(239)
Settlements	(1)	(27)	(5)	108	75
Transfers of assets/(liabilities), net into Level 3	(4)	—	—	—	(4)
Transfers of (assets)/liabilities, net out of Level 3	—	—	1	—	1
Balance at December 31	$ (4)	$ 59	$ (110)	$ (165)	$ (220)
Total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets and liabilities held at the end of the period	$ —	$ (4)	$ (13)	$ 14	$ (3)

Year Ended December 31, 2022	Derivative Assets and Liabilities				
	Interest Rate	Foreign Currency	Commodity	Contingent Consideration	Total
Balance at January 1	$ (6)	$ 108	$ (1)	$ (67)	$ 34
Total realized and unrealized gains (losses):					
Included in earnings	4	(26)	—	3	(19)
Included in other comprehensive income — derivative activity	15	(6)	(54)	—	(45)
Included in other comprehensive income — foreign currency translation activity	—	—	—	(2)	(2)
Included in regulatory (assets) liabilities	—	—	8	—	8
Acquisitions	—	—	—	(24)	(24)
Settlements	(2)	(12)	2	42	30
Transfers of assets/(liabilities), net into Level 3	(1)	—	—	—	(1)
Transfers of (assets)/liabilities, net out of Level 3	(10)	—	(2)	—	(12)
Balance at December 31	$ —	$ 64	$ (47)	$ (48)	$ (31)
Total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets and liabilities held at the end of the period	$ 3	$ (34)	$ 5	$ 3	$ (23)

The following table summarizes the significant unobservable inputs used for the Level 3 derivative assets (liabilities) as of December 31, 2023 (in millions, except range amounts):

Type of Derivative	Fair Value	Unobservable Input	Amount or Range (Weighted Average)
Interest rate	$ (4)	Subsidiary credit spread	0.4% - 3.3% (1.9%)
Foreign currency:			
Argentine peso	59	Argentine peso to USD currency exchange rate after one year	1,421 - 2,226 (1,879)
Commodity:			
CAISO Energy Swap	(107)	Forward energy prices per MWh after 2030	$13.13 - $121.53 ($63.51)
Other	(3)		
Total	$ (55)		

For the Argentine peso foreign currency derivatives, increases (decreases) in the estimate of the above exchange rate would increase (decrease) the value of the derivative. For the CAISO Energy Swap, increases (decreases) in the estimate above would decrease (increase) the value of the derivative.

Contingent consideration is primarily related to future milestone payments associated with acquisitions of renewable development projects. The estimated fair value of contingent consideration is determined using probability-weighted discounted cash flows based on internal forecasts, which are considered Level 3 inputs. Changes in Level 3 inputs, particularly changes in the probability of achieving development milestones, could result in material changes to the fair value of the contingent consideration and could materially impact the amount of expense or income recorded each reporting period. Contingent consideration is updated quarterly with any prospective changes in fair value recorded through earnings.

Nonrecurring Measurements —The Company measures fair value using the applicable fair value measurement guidance. Impairment expense, shown as pre-tax loss below, is measured by comparing the fair value at the evaluation date to the then-latest available carrying amount. The following table summarizes our major categories of asset groups measured at fair value on a nonrecurring basis and their level within the fair value hierarchy (in millions):

Year Ended December 31, 2023			**Fair Value**			
Assets	**Measurement Date**	**Carrying Amount** (1)	**Level 1**	**Level 2**	**Level 3**	**Pre-tax Loss**
Long-lived asset groups held and used: (2)						
Norgener (3)	5/1/2023	$ 196	$ —	$ —	$ 24	$ 137
GAF Projects (AES Renewable Holdings)	5/31/2023	29	—	—	11	18
TEG	7/31/2023	170	—	—	93	77
TEP	7/31/2023	153	—	—	94	59
New York Wind	11/30/2023	310	—	—	124	186
Warrior Run (4)	11/30/2023	250	—	—	25	198
Held-for-sale businesses: (5)						
Jordan (6)	3/31/2023	$ 179	$ —	$ 170	$ —	$ 14
Jordan (6)	6/30/2023	179	—	170	—	15
Jordan (6)	9/30/2023	178	—	170	—	14
Jordan (6)	12/31/2023	180	—	170	—	16
Mong Duong (7)	12/31/2023	575	—	413	—	167
Goodwill: (8)						
TEG TEP	10/1/2023	$ 12	$ —	$ —	$ —	$ 12

Year Ended December 31, 2022			**Fair Value**			
Assets	**Measurement Date**	**Carrying Amount** (1)	**Level 1**	**Level 2**	**Level 3**	**Pre-tax Loss**
Long-lived asset groups held and used: (2)						
Maritza	4/30/2022	$ 920	$ —	$ —	$ 452	$ 468
TEG	10/1/2022	268	—	—	164	104
TEP	10/1/2022	236	—	—	147	89
Held-for-sale businesses: (5)						
Jordan (6)	9/30/2022	$ 216	$ —	$ 170	$ —	$ 51
Jordan (6)	12/31/2022	190		170		25
Goodwill: (8)						
AES Andes	10/1/2022	$ 644	$ —	$ —	$ —	$ 644
AES El Salvador	10/1/2022	133	—	—	—	133
Equity method investments: (9)						
sPower	12/31/2022	$ 607	$ —	$ —	$ 432	$ 175

(1) Represents the carrying values at the dates of initial measurement, before fair value adjustment.

(2) See Note 22—*Asset Impairment Expense* for further information. Per ASC 360-10, the pre-tax impairment expense for long-lived asset groups held and used is limited to the carrying amount of the long-lived assets.

(3) The Norgener asset group includes long-lived assets, inventory, land, and other working capital, however per ASC 360-10, the pre-tax impairment expense is limited to the carrying amount of the long-lived assets. The Company evaluated the carrying amount of the assets outside the scope of ASC 360-10 and determined that the carrying value of the other assets should not be reduced.

(4) The Warrior Run asset group includes long-lived assets, inventory, and other working capital, however per ASC 360-10, the pre-tax impairment expense is limited to the carrying amount of the long-lived assets. The Company evaluated the carrying amount of the assets outside the scope of ASC 360-10 and recognized an inventory impairment of $6 million in *Other expense*. See Note 21—*Other Income and Expense* for further information.

(5) See Note 24—*Held-for-Sale and Dispositions* for further information.

(6) The pre-tax loss recognized was calculated using the $170 million fair value of the Jordan disposal group less costs to sell of $5 million for the September 30, 2022, December 31, 2022, and March 31, 2023 measurement dates and $6 million for the June 30, 2023, September 30, 2023 and December 31, 2023 measurement dates.

(7) The pre-tax loss recognized was calculated using the $413 million fair value of the Mong Duong disposal group less costs to sell of $5 million.

(8) See Note 9—*Goodwill and Other Intangible Assets* for further information.

(9) See Note 8—*Investments in and Advances to Affiliates* for further information.

AES Clean Energy Development Projects — On a quarterly basis, the Company reviews the status of development projects to identify projects that are no longer viable and will be abandoned. The fair value of each abandoned project with no salvage value is presumed to be zero as there are no future projected cash flows, resulting in a full write-off of the carrying value of project development intangibles and capitalized development costs incurred.

The Company recognized $151 million of pre-tax asset impairment expense in 2023, including $137 million during the fourth quarter, primarily related to the write-off of project development intangibles which were recognized at fair value when the Company acquired sPower's development platform as part of the formation of AES Clean Energy Development. See Note 22—*Asset Impairment Expense* for further information.

The following table summarizes the significant unobservable inputs used in the Level 3 measurement of long-lived asset groups held and used measured on a nonrecurring basis during the year ended December 31, 2023 (in millions, except range amounts):

December 31, 2023	Fair Value	Valuation Technique	Unobservable Input	Range (Weighted Average)
Long-lived asset groups held and used:				
New York Wind	$ 124	Discounted cash flow	Annual revenue growth	(1)% to 5% (2%)
			Annual variable margin	2% to 17% (9%)
TEP	94	Discounted cash flow	Annual revenue growth	(31)% to 6% (-2%)
			Annual variable margin	22% to 37% (26%)
			Discount rate	14% to 25% (14%)
TEG	93	Discounted cash flow	Annual revenue growth	(7)% to 9% (0%)
			Annual variable margin	14% to 33% (20%)
			Discount rate	14% to 25% (14%)
Warrior Run [(1)]	25	Discounted cash flow	Annual variable margin	(931)% to 74% (-506%)
Norgener [(2)]	24	Discounted cash flow	Annual revenue growth	(90)% to 994% (85%)
			Annual variable margin	(75)% to 276% (16%)
GAF Projects (AES Renewable Holdings)	11	Discounted cash flow	Annual revenue growth	(42)% to 44% (1%)
			Discount rate	9%
Total	$ 371			

(1) The fair value of the Warrior Run asset group is mainly related to cash on hand and existing coal inventory not subject to impairment under ASC 360-10, and is partially reduced by expected decommissioning and demolition costs.

(2) The fair value of the Norgener asset group subsequent to the impairment analysis performed on May 1, 2023 was mainly related to existing coal inventory not subject to impairment under ASC 360-10. In December 2023, the Company recognized an inventory impairment of $23 million in *Other expense*. See Note 21—*Other Income and Expense* for further information.

Financial Instruments not Measured at Fair Value in the Consolidated Balance Sheets

The following table presents (in millions) the carrying amount, fair value, and fair value hierarchy of the Company's financial assets and liabilities that are not measured at fair value in the Consolidated Balance Sheets as of the periods indicated, but for which fair value is disclosed:

		December 31, 2023				
		Carrying Amount	Fair Value			
			Total	Level 1	Level 2	Level 3
Assets:	Accounts receivable — noncurrent	$ 193	$ 239	$ —	$ —	$ 239
Liabilities:	Non-recourse debt	22,144	22,174	—	20,676	1,498
	Recourse debt	4,464	4,210	—	4,210	—

		December 31, 2022				
		Carrying Amount	Fair Value			
			Total	Level 1	Level 2	Level 3
Assets:	Accounts receivable — noncurrent [(1)]	$ 301	$ 340	$ —	$ —	$ 340
Liabilities:	Non-recourse debt	19,429	18,527	—	17,089	1,438
	Recourse debt	3,894	3,505	—	3,505	—

(1) These amounts primarily relate to amounts impacted by the Stabilization Fund enacted by the Chilean government. These amounts are included in *Other noncurrent assets* in the accompanying Consolidated Balance Sheets. See Note 7—*Financing Receivables* for further information.

6. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Volume of Activity — The following table presents the Company's maximum notional (in millions) over the remaining contractual period by type of derivative as of December 31, 2023, and the dates through which the maturities for each type of derivative range:

Interest Rate and Foreign Currency Derivatives	Maximum Notional Translated to USD	Latest Maturity
Interest rate	$ 7,738	2059
Cross-currency swaps (Brazilian Reais)	404	2026
Foreign currency:		
Chilean peso	216	2026
Euro	110	2026
Mexican peso	75	2024
Brazilian real	32	2026
Colombian peso	25	2025
Argentine peso	1	2026

Commodity Derivatives	Maximum Notional	Latest Maturity
Natural Gas (in MMBtu)	177	2029
Power (in MWhs)	23	2040
Coal (in Metric Tonnes)	4	2027

Accounting and Reporting — *Assets and Liabilities* — The following tables present the fair value of the Company's derivative assets and liabilities as of the periods indicated (in millions):

Fair Value	December 31, 2023			December 31, 2022		
Assets	Designated	Not Designated	Total	Designated	Not Designated	Total
Interest rate derivatives	$ 184	$ —	$ 184	$ 313	$ 1	$ 314
Foreign currency derivatives	23	51	74	27	59	86
Commodity derivatives	—	128	128	—	245	245
Total assets	$ 207	$ 179	$ 386	$ 340	$ 305	$ 645
Liabilities						
Interest rate derivatives	$ 108	$ —	$ 108	$ 6	$ —	$ 6
Cross-currency derivatives	63	—	63	42	—	42
Foreign currency derivatives	5	14	19	9	11	20
Commodity derivatives	107	149	256	59	347	406
Total liabilities	$ 283	$ 163	$ 446	$ 116	$ 358	$ 474

Fair Value	December 31, 2023		December 31, 2022	
	Assets	Liabilities	Assets	Liabilities
Current	$ 216	$ 152	$ 271	$ 168
Noncurrent	170	294	374	306
Total	$ 386	$ 446	$ 645	$ 474

Credit Risk-Related Contingent Features	December 31, 2023	December 31, 2022
Net position of derivatives subject to collateralization	$ (4)	$ 104
Cash collateral held by third parties or in escrow	104	42

Earnings and Other Comprehensive Income (Loss) — The following table presents the pre-tax gains (losses) recognized in AOCL and earnings related to all derivative instruments for the periods indicated (in millions):

	Years Ended December 31,		
	2023	2022	2021
Cash flow hedges			
Gains (losses) recognized in AOCL			
Interest rate derivatives	$ 42	$ 869	$ 51
Cross-currency derivatives	—	—	(11)
Foreign currency derivatives	2	17	(34)
Commodity derivatives	(48)	16	(1)
Total	$ (4)	$ 902	$ 5
Gains (losses) reclassified from AOCL to earnings			
Interest rate derivatives	$ 51	$ (72)	$ (419)
Cross-currency derivatives	—	—	(15)
Foreign currency derivatives	(4)	2	(62)
Commodity derivatives	17	2	4
Total	$ 64	$ (68)	$ (492)
Gains (losses) on fair value hedging relationships			
Cross-currency derivatives			
Derivatives designated as hedging instruments	$ (72)	$ (35)	$ (6)
Hedged items	58	26	4
Total	$ (14)	$ (9)	$ (2)
Loss reclassified from AOCL to earnings due to impairment of assets	$ —	$ (16)	$ —
Gains reclassified from AOCL to earnings due to change in forecast	$ 14	$ 26	$ —
Gain (losses) recognized in earnings related to			
Not designated as hedging instruments:			
Interest rate derivatives	$ (7)	$ 4	$ 105
Foreign currency derivatives	19	21	29
Commodity derivatives and other	261	(43)	(28)
Total	$ 273	$ (18)	$ 106

Reclassifications from AOCL to earnings are forecasted to increase pre-tax income from continuing operations by $36 million for the twelve months ended December 31, 2024, primarily related to interest rate derivatives.

7. FINANCING RECEIVABLES

Receivables with contractual maturities of greater than one year are considered financing receivables. The following table presents financing receivables by country as of the dates indicated (in millions).

	December 31, 2023			December 31, 2022		
	Gross Receivable	Allowance	Net Receivable	Gross Receivable	Allowance	Net Receivable
U.S.	$ 149	$ —	$ 149	$ 46	$ —	$ 46
Chile	33	—	33	239	—	239
Other	11	—	11	18	—	18
Total	$ 193	$ —	$ 193	$ 303	$ —	$ 303

U.S. — During this period, AES has recorded non-current receivables pertaining to the sale of the Redondo Beach land and the Warrior Run PPA termination agreement. The anticipated collection period extends beyond December 31, 2024. See Note 20—*Revenue* for further details regarding the Warrior Run PPA termination agreement.

Chile — AES Andes has recorded receivables pertaining to revenues recognized on regulated energy contracts that were impacted by the Stabilization Funds created by the Chilean government in October 2019 and August 2022, in conjunction with the Tariff Stabilization Laws. Historically, the government updated the prices for these contracts every six months to reflect the contracts' indexation to exchange rates and commodities prices. The Tariff Stabilization Laws do not allow the pass-through of these contractual indexation updates to customers beyond the pricing in effect at July 1, 2019, until new lower-cost renewable contracts are incorporated to supply regulated contracts. Consequently, costs incurred in excess of the July 1, 2019 price are accumulated and borne by generators. Through different programs, AES Andes aims to reduce its exposure and has already sold a significant portion of the receivables accumulated as of December 31, 2023.

On August 14, 2023, AES Andes executed an agreement aiming for the sale of up to $227 million of receivables pursuant to the Stabilization Funds, of which $131 million was sold and collected as of December 31, 2023. Through different agreements and programs, as of December 31, 2023, $17 million of current receivables and $8 million of noncurrent receivables were recorded in *Accounts receivable* and *Other noncurrent assets*, respectively. Additionally, $25 million of payment deferrals granted to mining customers as part of our green blend agreements were recorded as financing receivables included in *Other noncurrent assets* at December 31, 2023.

8. INVESTMENTS IN AND ADVANCES TO AFFILIATES

The following table summarizes the relevant effective equity ownership interest and carrying values for the Company's investments accounted for under the equity method as of the periods indicated:

December 31,		2023	2022	2023	2022
Affiliate	Country	Carrying Value (in millions)		Ownership Interest %	
sPower [(1)]	United States	$ 423	$ 432	50 %	50 %
Fluence	United States	148	205	29 %	34 %
Grupo Energía Gas Panamá [(2)]	Panama	114	82	24 %	49 %
Uplight [(3)]	United States	86	81	29 %	29 %
Energía Natural Dominicana Enadom [(4)]	Dominican Republic	77	64	33 %	43 %
Mesa La Paz	Mexico	42	32	50 %	50 %
Other affiliates [(5)]	Various	51	56		
Total		$ 941	$ 952		

(1) The Company owns 50% of sPower, LLC and accounts for its investment as an equity method investment. Furthermore, there are two specific portfolios of operating solar and wind assets, OpCo A and OpCo B, in which sPower, LLC owns 51%, resulting in an AES effective ownership of approximately 26% in these portfolios.

(2) The Company's ownership in Grupo Energía Gas Panamá is held through AES Panama, a 49%-owned consolidated subsidiary. AES Panama owns 49% of Grupo Energía Gas Panamá, resulting in an AES effective ownership of 24%.

(3) On February 9, 2024, the Company's equity interest was diluted to approximately 25% as a result of Uplight's acquisition of AutoGrid, a market leader in the fast-growing Virtual Power Plant ("VPP") space.

(4) The Company's ownership in Energía Natural Dominicana Enadom is held through Andres, a 65%-owned consolidated subsidiary. Andres owns 50% of Energía Natural Dominicana Enadom, resulting in an AES effective ownership of 33%. See Note 17—*Equity* for further information regarding the selldown of AES Dominicana in December 2023.

(5) Includes Bosforo, Tucano, Barry, Alto Maipo, and various other equity method investments. Barry and Alto Maipo represent VIEs in which the Company holds a variable interest but is not the primary beneficiary.

Fluence — In December 2023, the Company redeemed 7,087,500 common units of Fluence Energy, LLC. Fluence Energy, Inc. settled this redemption through the issuance of an equivalent number of shares of its Class A common stock. In conjunction with this redemption, the Company executed a public sale of the Class A shares, resulting in proceeds received of $156 million, after expenses, and a pre-tax gain on sale of $136 million, recorded in *Gain (loss) on disposal and sale of business interests*. As a result of this transaction, AES' ownership interest decreased from 33% to 29%. As the Company still does not control but has significant influence over Fluence after the transaction, it continues to be accounted for as an equity method investment. Fluence is reported in the New Energy Technologies SBU reportable segment.

Grupo Energía Gas Panamá — In September 2023, AES Latin America completed the sale of its interest in Grupo Energía Gas Panamá, a joint venture formed for the Gatun combined cycle natural gas development project, to AES Panama, a 49%-owned consolidated subsidiary. As a result of the transaction, the Company's effective ownership in Grupo Energía Gas Panamá decreased from 49% to approximately 24%. As the Company still does not control the investment after this transaction, it continues to be accounted for as an equity method investment and is reported in the Energy Infrastructure SBU reportable segment.

sPower — In December 2022, the Company agreed to sell 49% of its indirect interest in a portfolio of sPower's operating assets ("OpCo B"). At the time the purchase and sale agreement was signed, a loss was expected upon closing the transaction. The expected loss on sale was identified as a triggering event and the Company evaluated whether its investment in sPower was other-than-temporarily impaired. Based on management's estimate of fair value of $432 million, the Company recognized an other-than-temporary impairment of $175 million in *Other non-operating expense* in December 2022.

sPower primarily holds operating assets where the tax credits associated with underlying projects have already been allocated to tax equity investors. The application of HLBV accounting increases the carrying value of these investments, as earnings are initially disproportionately allocated to the sponsor entity. Since sPower does not have any ongoing development or other value creation activities following the transfer of these activities to AES Clean Energy Development, the impairment adjusts the carrying value to the fair market value of the operating assets.

On February 28, 2023, sPower closed on the sale for $196 million. As a result of the transaction, the Company received $98 million in sales proceeds and recorded a pre-tax gain on sale of $5 million, recorded in *Gain (loss) on disposal and sale of business interests*. After the sale, the Company's ownership interest in OpCo B decreased from 50% to approximately 26%. As the Company still does not control but has significant influence over sPower after the transaction, it continues to be accounted for as an equity method investment. sPower is reported in the Renewables SBU reportable segment.

Alto Maipo — In May 2022, Alto Maipo emerged from bankruptcy in accordance with Chapter 11 of the U.S. Bankruptcy Code. Alto Maipo, as restructured, is considered a VIE. As the Company lacks the power to make significant decisions, it does not meet the criteria to be considered the primary beneficiary of Alto Maipo and therefore will not consolidate the entity. The Company has elected the fair value option to account for its investment in Alto Maipo as management believes this approach will better reflect the economics of its equity interest. As of December 31, 2023, the fair value is insignificant. Alto Maipo is reported in the Energy Infrastructure SBU reportable segment.

Barry — The Company holds a 100% ownership interest in AES Barry Ltd. ("Barry"), a dormant entity in the U.K. that disposed of its generation and other operating assets. Due to a debt agreement, no material financial or operating decisions can be made without the banks' consent, and the Company does not control Barry. As of December 31, 2023 and 2022, other long-term liabilities included $41 million and $39 million, respectively, related to this debt agreement. Barry is reported in the Energy Infrastructure SBU reportable segment.

Summarized Financial Information — The following tables summarize financial information of the Company's 50%-or-less-owned affiliates and majority-owned unconsolidated subsidiaries that are accounted for using the equity method (in millions):

	50%-or-less Owned Affiliates			Majority-Owned Unconsolidated Subsidiaries[1]		
Years ended December 31,	**2023**	**2022**	**2021**	**2023**	**2022**	**2021**
Revenue	$ 2,905	$ 1,780	$ 1,316	$ 1	$ 1	$ 1
Operating loss	(28)	(361)	(53)	(1)	(1)	(1)
Net loss	(182)	(527)	(242)	(1)	—	(3)
Net loss attributable to affiliates	(157)	(405)	(40)	(1)	—	(3)
December 31,	**2023**	**2022**		**2023**	**2022**	
Current assets	$ 1,759	$ 2,223		$ 117	$ 125	
Noncurrent assets	7,569	7,522		533	643	
Current liabilities	1,638	1,931		114	118	
Noncurrent liabilities	4,085	4,040		572	677	
Stockholders' equity	2,318	2,978		(30)	(26)	
Noncontrolling interests	1,287	796		(6)	(1)	

(1) The summarized financial information of Alto Maipo is not included in the table above as the Company is not the primary beneficiary, the fair value of the investment is insignificant, and the investment in Alto Maipo is not material to the financial results of the Company.

At December 31, 2023, retained earnings included $325 million related to the undistributed losses of the Company's 50%-or-less owned affiliates. Dividends received from these affiliates were $5 million, $47 million, and $25 million for the years ended December 31, 2023, 2022, and 2021, respectively. As of December 31, 2023, the aggregate carrying amount of our investments in equity affiliates exceeded the underlying equity in the net assets of our equity affiliates by $118 million.

9. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill — The following table summarizes the carrying amount of goodwill by reportable segment for the years ended December 31, 2023 and 2022 (in millions):

	Renewables SBU	Utilities SBU	Energy Infrastructure SBU	New Energy Technologies SBU	Total
Balance as of December 31, 2022					
Goodwill	$ 355	$ 2,709	$ 683	$ 3	$ 3,750
Accumulated impairment losses	(35)	(2,709)	(644)	—	(3,388)
Net balance	320	—	39	3	362
Impairment losses	—	—	(12)	—	(12)
Goodwill derecognized during the year	(2)	—	—	—	(2)
Balance as of December 31, 2023					
Goodwill	353	2,709	683	3	3,748
Accumulated impairment losses	(35)	(2,709)	(656)	—	(3,400)
Net balance	$ 318	$ —	$ 27	$ 3	$ 348

TEG TEP — During the fourth quarter of 2023, the Company performed the goodwill impairment test for the TEG TEP reporting unit. The fair value of the reporting unit was determined under the income approach using a discounted cash flow valuation model. The estimated fair value was less than its carrying amount and as a result the Company recognized impairment expense of $12 million, reducing the goodwill balance of TEG TEP to zero. The decrease in fair value since the date of our last impairment test on July 31, 2023 was primarily driven by an increase in the discount rate due to increasing risk of non-renewal of operating permits required to operate after March 31, 2024. In February 2024, the Mexican Comision Reguladora de Energia ("CRE") rejected TEG's request to transition to the new energy regime and renew its operating permits. This request was denied on the basis of a lawsuit concerning the electricity law that has been withdrawn. TEG has subsequently reiterated with the agency the lawsuit has been withdrawn and has formally requested that CRE issue a new permit. TEG and TEP are reported in the Energy Infrastructure SBU reportable segment.

AES Andes — During the fourth quarter of 2022, the Company performed the annual goodwill impairment test for the AES Andes reporting unit. The fair value of the reporting unit was determined under the income approach using a discounted cash flow valuation model. The estimated fair value was less than its carrying amount and as a result the Company recognized impairment expense of $644 million, reducing the goodwill balance of AES Andes to zero. The decrease in fair value since the date of our last impairment test was primarily driven by a higher discount rate resulting from increased interest rates and country risk premiums, as well as a decrease in forecasted energy prices and other unfavorable macroeconomic assumptions in Colombia. AES Andes is reported in the Energy Infrastructure SBU reportable segment.

AES El Salvador — During the fourth quarter of 2022, the Company performed the annual goodwill impairment test for the El Salvador reporting unit. The Company performed a quantitative impairment test and utilized the income approach. The estimated fair value was less than its carrying amount and as a result the Company recognized goodwill impairment expense of $133 million, reducing the goodwill balance of AES El Salvador to zero. Since the date of our last impairment test in 2021, the Company has seen market participants substantially increase return expectations for the perceived country risk for El Salvador. The impact of the increase has substantially increased our discount rate, resulting in a full impairment. AES El Salvador is reported in the Utilities SBU reportable segment.

Other Intangible Assets — The following table summarizes the balances comprising *Other intangible assets* in the accompanying Consolidated Balance Sheets (in millions) as of the periods indicated:

	December 31, 2023						December 31, 2022					
	Gross Balance		Accumulated Amortization		Net Balance		Gross Balance		Accumulated Amortization		Net Balance	
Subject to Amortization												
Internal-use software	$	696	$	(324)	$	372	$	582	$	(307)	$	275
Contracts		337		(37)		300		342		(40)		302
Project development rights [1]		1,222		(43)		1,179		991		(17)		974
Emissions allowances [2]		50		—		50		37		—		37
Concession rights		222		(71)		151		207		(50)		157
Land use rights		119		(3)		116		20		(1)		19
Other [3]		45		(20)		25		37		(19)		18
Subtotal		2,691		(498)		2,193		2,216		(434)		1,782
Indefinite-Lived Intangible Assets												
Land use rights		22		—		22		42		—		42
Transmission rights		20		—		20		16		—		16
Other		8		—		8		1		—		1
Subtotal		50		—		50		59		—		59
Total	$	2,741	$	(498)	$	2,243	$	2,275	$	(434)	$	1,841

(1) Includes emission offset fee to the Air Quality Management District ("AQMD") in order to transfer emission offsets from retired legacy Southland units to the new CCGT.
(2) Acquired or purchased emissions allowances are finite-lived intangible assets that are expensed when utilized and included in net income for the year.
(3) Includes management rights, renewable energy credits and incentives, and other individually insignificant intangible assets.

The following tables summarize other intangible assets acquired during the periods indicated (in millions):

December 31, 2023		Amount	Subject to Amortization/ Indefinite-Lived	Weighted Average Amortization Period (in years)	Amortization Method
Internal-use software	$	159	Subject to Amortization	15	Straight-line
Contracts		12	Subject to Amortization	21	Straight-line
Project development rights		242	Subject to Amortization	39	Straight-line
Emissions allowances		23	Subject to Amortization	Various	As utilized
Land use rights		91	Various	N/A	Various
Other		9	Various	N/A	N/A
Total	$	536			

December 31, 2022		Amount	Subject to Amortization/ Indefinite-Lived	Weighted Average Amortization Period (in years)	Amortization Method
Internal-use software	$	136	Subject to Amortization	14	Straight-line
Contracts		196	Subject to Amortization	23	Straight-line
Project development rights		67	Subject to Amortization	4	Straight-line
Emissions allowances		35	Subject to Amortization	Various	As utilized
Land use rights		13	Indefinite-Lived	N/A	N/A
Other		1	Subject to Amortization	N/A	N/A
Total	$	448			

The following table summarizes the estimated amortization expense by intangible asset category for 2024 through 2028:

(in millions)	2024		2025		2026		2027		2028	
Internal-use software	$	42	$	39	$	37	$	34	$	34
Contracts		21		17		17		17		17
Concession rights		17		17		17		17		17
Project development rights		10		10		12		12		12
Other		2		6		6		4		5
Total	$	92	$	89	$	89	$	84	$	85

Intangible asset amortization expense was $82 million, $71 million and $69 million for the years ended December 31, 2023, 2022 and 2021, respectively.

10. REGULATORY ASSETS AND LIABILITIES

The Company has recorded regulatory assets and liabilities (in millions) that it expects to pass through to its customers in accordance with, and subject to, regulatory provisions as follows:

December 31,	2023	2022	Recovery/Refund Period
Regulatory assets			
Current regulatory assets:			
Undercollection of rate riders	$ 127	$ 65	1 year
El Salvador energy pass through costs recovery	119	78	Quarterly
AES Indiana deferred fuel and purchased power costs	—	80	1 year
Other	19	14	1 year
Total current regulatory assets	265	237	
Noncurrent regulatory assets:			
AES Indiana Petersburg Units 1 and 2 retirement costs	260	287	10 years
AES Indiana and AES Ohio defined benefit pension obligations [1]	179	194	Various
AES Indiana environmental costs	70	73	Various
AES Ohio regulatory compliance costs	45	6	5 years
AES Indiana deferred Midcontinent ISO costs	21	34	3 years
Other	123	130	Various
Total noncurrent regulatory assets	698	724	
Total regulatory assets	$ 963	$ 961	
Regulatory liabilities			
Current regulatory liabilities:			
Overcollection of costs to be passed back to customers	$ 34	$ 46	1 year
Other	7	18	1 year
Total current regulatory liabilities	41	64	
Noncurrent regulatory liabilities:			
AES Indiana and AES Ohio accrued costs of removal and AROs	586	657	Over life of assets
AES Indiana and AES Ohio income taxes payable to customers through rates	117	134	Various
Other	6	22	Various
Total noncurrent regulatory liabilities	709	813	
Total regulatory liabilities	$ 750	$ 877	

(1) Past expenditures on which the Company earns a rate of return.

Our regulatory assets and current regulatory liabilities primarily consist of under or overcollection of costs that are generally non-controllable, such as purchased electricity, energy transmission, fuel costs, and other sector costs. These costs are recoverable or refundable as defined by the laws and regulations in our markets. Our regulatory assets also include defined pension and postretirement benefit obligations equal to the previously unrecognized actuarial gains and losses and prior service costs that are expected to be recovered through future rates. Additionally, our regulatory assets include the carrying value of AES Indiana's Petersburg Unit 1 and Petersburg Unit 2 at their retirement dates, which are amortized over the life of the assets beginning on the dates of retirement. Other current and noncurrent regulatory assets primarily consist of:

- Deferred Midcontinent ISO costs at AES Indiana;
- Deferred TDSIC costs and unamortized premiums reacquired or redeemed on long-term debt, which are amortized over the lives of the original issuances, at AES Indiana; and
- Vegetation management costs and proactive reliability optimization at AES Ohio.

Our noncurrent regulatory liabilities primarily consist of obligations for removal costs which do not have an associated legal retirement obligation. Our noncurrent regulatory liabilities also include deferred income taxes related to differences in income recognition between tax laws and accounting methods, which will be passed through to our regulated customers via a decrease in future retail rates.

In the accompanying Consolidated Balance Sheets, current regulatory assets and liabilities are reflected in *Other current assets* and *Accrued and other liabilities*, respectively, and noncurrent regulatory assets and liabilities are reflected in *Other noncurrent assets* and *Other noncurrent liabilities*, respectively. All of the regulatory assets and liabilities as of December 31, 2023 and December 31, 2022 are related to the Utilities SBU reportable segment.

11. DEBT

NON-RECOURSE DEBT — The following table summarizes the carrying amount and terms of non-recourse debt at our subsidiaries as of the periods indicated (in millions):

NON-RECOURSE DEBT	Weighted Average Interest Rate	Maturity	December 31, 2023	December 31, 2022
Variable Rate:				
Bank loans	7.39%	2024 - 2045	$ 5,568	$ 3,306
Notes and bonds	4.62%	2024 - 2047	1,768	2,137
Revolver borrowings	7.18%	2024 - 2027	2,356	1,832
Other	11.85%	2024 - 2030	31	71
Fixed Rate:				
Bank loans	7.20%	2024 - 2064	1,473	461
Notes and bonds	5.09%	2024 - 2079	11,228	11,130
Other [(1)]	5.90%	2024 - 2061	53	801
Unamortized (discount) premium & debt issuance (costs), net			(333)	(309)
Subtotal			$ 22,144	$ 19,429
Less: Current maturities [(2)]			(3,924)	(1,752)
Noncurrent maturities [(2)]			$ 18,220	$ 17,677

(1) Other fixed rate debt as of December 31, 2022 includes $756 million at Mong Duong, which was classified as held and used as of December 31, 2022, but is classified as held-for-sale as of December 31, 2023. See Note 24—*Held-for-Sale and Dispositions* for further information.

(2) Excludes $8 million and $6 million (current) and $262 million and $169 million (noncurrent) finance lease liabilities included in the respective non-recourse debt line items on the Consolidated Balance Sheets as of December 31, 2023 and 2022, respectively. See Note 14—*Leases* for further information.

The interest rate on variable rate debt represents the total of a variable component that is based on changes in an interest rate index and a fixed component. The Company has interest rate swap agreements that economically fix the variable component of the interest rates on the portion of the variable rate debt being hedged in an aggregate notional principal amount of approximately $2.7 billion on non-recourse debt outstanding at December 31, 2023.

The following table summarizes the amounts due under our non-recourse debt agreements for the next five years and thereafter, as of December 31, 2023 (in millions):

December 31,	Annual Maturities
2024	$ 3,935
2025	2,232
2026	3,515
2027	2,566
2028	932
Thereafter	9,297
Unamortized (discount) premium & debt issuance (costs), net	(333)
Total	$ 22,144

As of December 31, 2023, AES subsidiaries with facilities under construction had a total of approximately $1.3 billion of committed but unused credit facilities available to fund construction and other related costs. Excluding these facilities under construction, AES subsidiaries had approximately $1.7 billion in various unused committed credit lines to support their working capital, debt service reserves and other business needs. These credit lines can be used for borrowings, letters of credit, or a combination of these uses.

Significant transactions — During the year ended December 31, 2023, the Company's following subsidiaries had significant debt issuances (in millions):

Subsidiary	Issuances [(1)]
AES Clean Energy	$ 2,654
Netherlands and Colon	350
AES Indiana	300
AES Ohio	300

(1) These amounts do not include revolving credit facility activity at the Company's subsidiaries.

AES Ohio — The $300 million of debt issued at AES Ohio is primarily related to $200 million of First Mortgage Bonds issued in December 2023 in a private placement offering, in which AES Ohio issued $92 million aggregate principal of 5.49% bonds and $108 million aggregate principal of 5.70% bonds due in 2028 and 2033, respectively. The net proceeds from the issuances were used primarily to repay existing indebtedness and for general corporate purposes.

AES Indiana — In November 2023, AES Indiana executed a $300 million term loan due in 2024. The net proceeds from this issuance were used for general corporate purposes.

Netherlands and Colon — In March 2022, AES Hispanola Holdings BV, a Netherlands based company, and Colon, as co-borrowers, executed a $500 million bridge loan due in 2023. The Company allocated $450 million and $50 million of the proceeds from the agreement to AES Hispanola Holdings BV and Colon, respectively.

In January 2023, AES Hispanola Holdings BV and Colon, as co-borrowers, executed a $350 million credit agreement at 8.85%, due in 2028. The Company allocated $300 million and $50 million of the proceeds from the agreement to AES Hispanola Holdings BV and Colon, respectively. The net proceeds from the agreement were used to partially repay the $500 million bridge loan executed in 2022. The remaining principal outstanding of the bridge loan was repaid with proceeds from operating cash flows as well as cash from the Parent Company. As a result of these transactions, the Company recognized a loss on extinguishment of debt of $1 million.

United Kingdom — On January 6, 2022, Mercury Chile HoldCo LLC ("Mercury Chile"), a UK based company, executed a $350 million bridge loan and used the proceeds, as well as an additional capital contribution of $196 million from the Parent Company, to purchase the minority interest in AES Andes through intermediate holding companies (see Note 17—*Equity* for further information). On January 24, 2022, Mercury Chile issued $360 million aggregate principal of 6.5% senior secured notes due in 2027 and used the proceeds from the issuance to fully prepay the $350 million bridge loan.

AES Clean Energy — In December 2023, Bellefield Portfolio Seller, LLC and Bellefield 1 Finco, LLC, subsidiaries of AES Clean Energy Development, executed a construction, tax equity bridge, and letter of credit financing agreement for commitments of up to $2.4 billion due in 2026. As of December 31, 2023, there was $998 million in outstanding borrowings under the facilities, and the net proceeds were used primarily to repay existing indebtedness and to fund development of renewables projects.

In October 2023, Rexford I Holdings, LLC, a subsidiary of AES Renewable Holdings, executed a $300 million bridge loan due in 2024. The net proceeds from this issuance were used primarily to fund development of renewables projects.

In December 2022, AES Renewable Holdings OpCo 1, LLC executed a term loan in the amount of $632 million due in 2027. The proceeds were used to prepay the outstanding principal of $692 million of its six credit facilities. As a result of this transaction, the Company recognized a loss on extinguishment of debt of $12 million.

In December 2022, AES Clean Energy Development, AES Renewable Holdings, and sPower, an equity method investment, collectively referred to as the Issuers, entered into a Master Indenture agreement whereby long-term notes will be issued from time to time to finance or refinance operating wind, solar, and storage projects that are owned by the Issuers. On December 13, 2022, the Issuers entered into the Note Purchase Agreement for the issuance of up to $647 million of 6.55% Senior Notes due in 2047. The Notes were sold on December 14, 2022, at par for $647 million. In 2023, the Issuers sold an additional $246 million in 6.37% notes. As a result of the additional issuance and repayments, the aggregate principal amount of Notes outstanding was $884 million as of December 31, 2023. Each of the Issuers is considered a "Co-Issuer" and will be jointly and severally liable with each other Co-Issuer for all obligations under the facility. As a result of the 2023 issuance, AES Clean Energy Development recorded an increase in liabilities of $215 million, resulting in an aggregate carrying amount of the Notes attributable to AES Clean Energy Development and AES Renewable Holdings of $252 million as of December 31, 2023.

In 2021, AES Clean Energy Development, AES Renewable Holdings, and sPower, collectively referred to as the Borrowers, executed two Credit Agreements with aggregate commitments of $1.2 billion and maturity dates in December 2024 and September 2025. The Borrowers executed amendments to the revolving credit facilities, which have resulted in an aggregate increase in the commitments of $2.6 billion, bringing the total commitments under the new agreements to $3.8 billion. Under a 2023 amendment, the maturity date of one of the Credit Agreements was extended from December 2024 to May 2026. Each of the Borrowers is considered a “Co-Borrower” and will be jointly and severally liable with each other Co-Borrower for all obligations under the facilities. As a result of increases in commitments used, AES Clean Energy Development and AES Renewable Holdings recorded, in aggregate, an increase in liabilities of $1 billion in 2023, resulting in total commitments used under the revolving credit facilities, as of December 31, 2023, of $2.3 billion. As of December 31, 2023, the aggregate commitments used under the revolving credit facilities for the Co-Borrowers was $2.8 billion.

Non-Recourse Debt Covenants, Restrictions and Defaults — The terms of the Company's non-recourse debt include certain financial and nonfinancial covenants. These covenants are limited to subsidiary activity and vary among the subsidiaries. These covenants may include, but are not limited to, maintenance of certain reserves and financial ratios, minimum levels of working capital and limitations on incurring additional indebtedness.

As of December 31, 2023 and 2022, approximately $341 million and $424 million, respectively, of restricted cash was maintained in accordance with certain covenants of the non-recourse debt agreements. Of these amounts, $158 million and $285 million, respectively, were included within *Restricted cash* and $183 million and $139 million, respectively, were included within *Debt service reserves and other deposits* in the accompanying Consolidated Balance Sheets. As of December 31, 2023 and 2022, approximately $90 million and $56 million, respectively, of the restricted cash balances were for collateral held to cover potential liability for current and future insurance claims being assumed by AGIC, AES' captive insurance company.

Various lender and governmental provisions restrict the ability of certain of the Company's subsidiaries to transfer their net assets to the Parent Company. Such restricted net assets of subsidiaries amounted to approximately $901 million at December 31, 2023.

The following table summarizes the Company's subsidiary non-recourse debt in default (in millions) as of December 31, 2023. Due to the defaults, these amounts are included in the current portion of non-recourse debt:

Subsidiary	Primary Nature of Default	December 31, 2023 Debt in Default	December 31, 2023 Net Assets
AES Mexico Generation Holdings (TEG and TEP)	Covenant	$ 150	$ 24
AES Puerto Rico	Covenant/Payment	143	(170)
AES Ilumina (Puerto Rico)	Covenant	25	29
AES Jordan Solar	Covenant	7	11
Total		$ 325	

The amounts in default related to AES Puerto Rico are covenant and payment defaults. In July 2023, AES Puerto Rico signed forbearance and standstill agreements with its noteholders because of the insufficiency of funds to meet the principal and interest obligations on its Series A Bond Loans due and payable on June 1, 2023, and going forward. These agreements expired on December 31, 2023 and were extended until January 17, 2024. Although there is no forbearance in place after January 17, 2024, AES Puerto Rico continues to work with PREPA and its noteholders on these liquidity challenges.

All other defaults listed are not payment defaults. All other subsidiary non-recourse defaults were triggered by failure to comply with covenants or other requirements contained in the non-recourse debt documents of the applicable subsidiary.

The AES Corporation's recourse debt agreements include cross-default clauses that will trigger if a subsidiary provides 20% or more of the Parent Company's total cash distributions from businesses for the four most recently completed fiscal quarters and has an outstanding principal in excess of $200 million in default. As of December 31, 2023, the Company's subsidiaries had no defaults which resulted in a cross-default under the recourse debt of the Parent Company. In the event the Parent Company is not in compliance with the financial covenants of its revolving credit facility, restricted payments will be limited to regular quarterly shareholder dividends at the then-prevailing rate. Payment defaults and bankruptcy defaults would preclude the making of any restricted payments.

RECOURSE DEBT — The following table summarizes the carrying amount and terms of recourse debt of the Company as of the periods indicated (in millions):

	Interest Rate	Final Maturity	December 31, 2023	December 31, 2022
Senior Variable Rate Term Loan	SOFR + 1.125%	2024	$ 200	$ 200
Senior Unsecured Note	3.30%	2025	900	900
Senior Unsecured Note	1.375%	2026	800	800
Drawings on revolving credit facility	SOFR + 1.75%	2027	—	325
Senior Unsecured Note	5.45%	2028	900	—
Senior Unsecured Note	3.95%	2030	700	700
Senior Unsecured Note	2.45%	2031	1,000	1,000
Unamortized (discount) premium & debt issuance (costs), net			(36)	(31)
Subtotal			$ 4,464	$ 3,894
Less: Current maturities			(200)	—
Noncurrent maturities			$ 4,264	$ 3,894

The following table summarizes the principal amounts due under our recourse debt for the next five years and thereafter (in millions):

December 31,	Annual Maturities
2024	$ 200
2025	900
2026	800
2027	—
2028	900
Thereafter	1,700
Unamortized (discount) premium & debt issuance (costs), net	(36)
Total recourse debt	$ 4,464

Senior Notes due 2028 — In May 2023, the Company issued $900 million aggregate principal of 5.45% senior notes due in 2028. The Company used the proceeds from this issuance for general corporate purposes and to fund investments in the Company's Renewables and Utilities SBUs.

AES Clean Energy Development — In March 2023, AES Clean Energy Development Holdings, LLC executed a $500 million bridge loan due in December 2023 and used the proceeds for general corporate purposes. The obligations under the bridge loan were unsecured and fully guaranteed by the Parent Company. The bridge loan was repaid in December 2023.

Commercial Paper Program — In March 2023, the Company established a commercial paper program under which the Company may issue unsecured commercial paper notes (the "Notes") up to a maximum aggregate face amount of $750 million outstanding at any time. The maturities of the Notes may vary but will not exceed 397 days from the date of issuance. The proceeds of the Notes will be used for general corporate purposes. The Notes will be sold on customary terms in the U.S. commercial paper market on a private placement basis. The commercial paper program is backed by the Company's $1.5 billion revolving credit facility, and the Company cannot issue commercial paper in an aggregate amount exceeding the then available capacity under its revolving credit facilities. During 2023, the Company borrowed and repaid approximately $45.8 billion under the commercial paper program, with average daily outstanding borrowings of $449 million. As of December 31, 2023, the Company had no outstanding borrowings under the commercial paper program.

Revolving Credit Facility — In September 2022, AES executed an amendment to its revolving credit facility. The aggregate commitment under the new agreement is $1.5 billion and matures in August 2027. The existing credit agreement had an aggregate commitment of $1.25 billion and matured in September 2026. As of December 31, 2023, AES had no outstanding drawings under its revolving credit facility.

Term Loan due 2024 — In September 2022, the AES Corporation entered into a term loan agreement, under which AES can obtain term loans in an aggregate principal amount of up to $200 million, with all term loans to mature no later than September 30, 2024. On September 30, 2022 the AES Corporation borrowed $200 million under this agreement with a maturity date of September 30, 2024.

Recourse Debt Covenants and Guarantees — The Company's obligations under the revolving credit facility and indentures governing the senior notes due 2025 and 2030 are currently unsecured following the achievement of two investment grade ratings and the release of security in accordance with the terms of the facility and the notes. If the Company's credit rating falls below "Investment Grade" from at least two of Fitch Investors Service Inc., Standard & Poor's Ratings Services or Moody's Investors Service, Inc., as determined in accordance with the terms of the revolving credit facility and indenture dated May 15, 2020 (BBB-, or in the case of Moody's Investor Services, Inc. Baa3), then the obligations under the revolving credit facility and the indentures governing the senior notes due 2025 and 2030 become, subject to certain exceptions, secured by (i) all of the capital stock of domestic subsidiaries owned directly by the Company or certain subsidiaries and 65% of the capital stock of certain foreign subsidiaries owned directly by the Company and certain subsidiaries, and (ii) certain intercompany receivables, certain intercompany notes and certain intercompany tax sharing agreements.

The revolving credit facility contains customary covenants and restrictions on the Company's ability to engage in certain activities, including, but not limited to, limitations on liens; restrictions on mergers and acquisitions and the disposition of assets; and other financial reporting requirements.

The revolving credit facility also contains one financial covenant, evaluated quarterly, requiring the Company to maintain a maximum ratio of recourse debt to adjusted operating cash flow of 5.75 times.

The terms of the Company's senior notes contain certain customary covenants, including limitations on the Company's ability to incur liens or enter into sale and leaseback transactions.

12. COMMITMENTS

The Company enters into long-term contracts for construction projects, maintenance and service, transmission of electricity, operations services and purchases of electricity and fuel. In general, these contracts are subject to variable quantities or prices and are terminable only in limited circumstances. The following table shows the future minimum commitments for continuing operations under these contracts as of December 31, 2023 for 2024 through 2028 and thereafter as well as actual purchases under these contracts for the years ended December 31, 2023, 2022, and 2021 (in millions):

Actual purchases during the year ended December 31,	**Electricity Purchase Contracts**	**Fuel Purchase Contracts**	**Other Purchase Contracts**
2021	$ 709	$ 2,070	$ 1,261
2022	1,156	3,375	3,602
2023	1,134	1,982	3,181
Future commitments for the year ending December 31,			
2024	$ 1,222	$ 2,069	$ 4,698
2025	962	1,678	1,047
2026	700	1,166	737
2027	686	1,222	718
2028	656	1,056	629
Thereafter	5,873	3,874	1,720
Total	$ 10,099	$ 11,065	$ 9,549

13. CONTINGENCIES

Parent Guarantees and Letters of Credit — In connection with certain project financings (including tax equity transactions), acquisitions and dispositions, power purchases, EPC contracts, and other agreements, the Parent Company has expressly undertaken limited obligations and commitments, most of which will only be effective or will be terminated upon the occurrence of future events. In the normal course of business, the Parent Company has entered into various agreements, mainly guarantees and letters of credit, to provide financial or performance assurance to third parties on behalf of AES businesses. These agreements are entered into primarily to support or enhance the creditworthiness otherwise achieved by a business on a stand-alone basis, thereby facilitating the availability of sufficient credit to accomplish their intended business purposes. Most of the contingent obligations relate to future performance commitments which the Company or its businesses expect to fulfill within the normal course of business. The expiration dates of these guarantees vary from less than one year to no more than 33 years.

The following table summarizes the Parent Company's contingent contractual obligations as of December 31, 2023. Amounts presented in the following table represent the Parent Company's current undiscounted exposure to guarantees and the range of maximum undiscounted potential exposure per individual agreement. The maximum exposure is not reduced by the amounts, if any, that could be recovered under the recourse or collateralization provisions in the guarantees.

Contingent Contractual Obligations	Maximum Exposure (in millions)	Number of Agreements	Maximum Exposure Range for Each Agreement (in millions)
Guarantees and commitments	$ 3,978	90	< $1 — 970
Letters of credit under bilateral agreements	235	4	$54 — 64
Letters of credit under the unsecured credit facilities	188	31	< $1 — 70
Letters of credit under the revolving credit facility	124	17	< $1 — 40
Surety bonds	2	2	< $1 — 1
Total	$ 4,527	144	

During the year ended December 31, 2023, the Parent Company paid letter of credit fees ranging from 1% to 3% per annum on the outstanding amounts of letters of credit.

Subsidiary Guarantees and Letters of Credit — In connection with certain project financings (including tax equity transactions), acquisitions and dispositions, power purchases, EPC contracts, and other agreements, certain of the Company's subsidiaries have expressly undertaken limited obligations and commitments, most of which will only be effective or will be terminated upon the occurrence of future events, or are customary payment guarantees for amounts due under existing contracts in the normal course of business. These contingent contractual obligations are issued at the subsidiary level and are non-recourse to the Parent Company. As of December 31, 2023, the maximum undiscounted potential exposure to guarantees issued by our subsidiaries was $2.8 billion, including $1.8 billion of customary payment guarantees under EPC contracts and other agreements, and $1 billion of tax equity financing related guarantees. In addition, as of December 31, 2023, our subsidiaries had $359 million of letters of credit outstanding.

Environmental — The Company periodically reviews its obligations as they relate to compliance with environmental laws, including site restoration and remediation. For the periods ended December 31, 2023 and 2022, the Company recognized liabilities of $9 million and $10 million, respectively, for projected environmental remediation costs. Due to the uncertainties associated with environmental assessment and remediation activities, future costs of compliance or remediation could be higher or lower than the amount currently accrued. Moreover, where no liability has been recognized, it is reasonably possible that the Company may be required to incur remediation costs or make expenditures in amounts that could be material but could not be estimated as of December 31, 2023. In aggregate, the Company estimates the range of potential losses related to environmental matters, where estimable, to be up to $13 million. The amounts considered reasonably possible do not include amounts accrued as discussed above.

Litigation — The Company is involved in certain claims, suits and legal proceedings in the normal course of business. The Company accrues for litigation and claims when it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. The Company has recognized aggregate liabilities for all claims of approximately $17 million and $22 million as of December 31, 2023 and 2022, respectively. These amounts are reported on the Consolidated Balance Sheets within *Accrued and other liabilities* and *Other noncurrent liabilities*. A significant portion of these accrued liabilities relate to regulatory matters and commercial disputes in international jurisdictions. There can be no assurance that these accrued liabilities will be adequate to cover all existing and future claims or that we will have the liquidity to pay such claims as they arise.

Where no accrued liability has been recognized, it is reasonably possible that some matters could be decided unfavorably to the Company and could require the Company to pay damages or make expenditures in amounts that could be material but could not be estimated as of December 31, 2023. The material contingencies where a loss is reasonably possible primarily include disputes with offtakers, suppliers and EPC contractors; alleged breaches of contract; alleged violation of laws and regulations; income tax and non-income tax matters with tax authorities; and regulatory matters. In aggregate, the Company estimates the range of potential losses, where estimable, related to these reasonably possible material contingencies to be between $146 million and $185 million. The amounts considered reasonably possible do not include the amounts accrued, as discussed above. These material contingencies do not include income tax-related contingencies which are considered part of our uncertain tax positions. See Note 23—*Income Taxes* for further information.

14. LEASES

LESSEE — Right-of-use assets are long-term by nature. The following table summarizes the amounts recognized on the Consolidated Balance Sheets related to lease asset and liability balances as of the periods indicated (in millions):

	Consolidated Balance Sheet Classification	December 31, 2023	December 31, 2022
Assets			
Right-of-use assets — finance leases	Electric generation, distribution assets and other	$ 250	$ 160
Right-of-use assets — operating leases	Other noncurrent assets	380	356
Total right-of-use assets		$ 630	$ 516
Liabilities			
Finance lease liabilities (current)	Non-recourse debt (current liabilities)	$ 8	$ 6
Finance lease liabilities (noncurrent)	Non-recourse debt (noncurrent liabilities)	262	169
Total finance lease liabilities		270	175
Operating lease liabilities (current)	Accrued and other liabilities	37	26
Operating lease liabilities (noncurrent)	Other noncurrent liabilities	387	374
Total operating lease liabilities		424	400
Total lease liabilities		$ 694	$ 575

The following table summarizes supplemental balance sheet information related to leases as of the periods indicated:

Lease Term and Discount Rate	December 31, 2023	December 31, 2022
Weighted-average remaining lease term — finance leases	34 years	33 years
Weighted-average remaining lease term — operating leases	27 years	25 years
Weighted-average discount rate — finance leases	5.36 %	4.59 %
Weighted-average discount rate — operating leases	7.70 %	6.22 %

The following table summarizes the components of lease cost recognized in *Cost of Sales* on the Consolidated Statements of Operations for the periods indicated (in millions):

	Years Ended December 31,	
Components of Lease Cost	**2023**	**2022**
Operating lease cost	$ 52	$ 46
Finance lease cost:		
Amortization of right-of-use assets	7	8
Interest on lease liabilities	10	8
Short-term lease costs	16	28
Variable lease cost	—	1
Total lease cost	$ 85	$ 91

Operating cash outflows from operating leases included in the measurement of lease liabilities were $54 million and $54 million for the years ended December 31, 2023 and 2022, respectively, and operating cash outflows from finance leases were $5 million and $22 million for the years ended December 31, 2023 and 2022, respectively. Right-of-use assets obtained in exchange for new operating and finance lease liabilities were $129 million and $96 million, respectively, for the years ended December 31, 2023.

The following table shows the future lease payments under operating and finance leases for continuing operations together with the present value of the net lease payments as of December 31, 2023 for 2024 through 2028 and thereafter (in millions):

	Maturity of Lease Liabilities	
	Finance Leases	**Operating Leases**
2024	$ 14	$ 56
2025	14	45
2026	15	43
2027	15	41
2028	15	38
Thereafter	545	986
Total	618	1,209
Less: Imputed interest	(348)	(785)
Present value of lease payments	$ 270	$ 424

LESSOR — The Company has operating leases for certain generation contracts that contain provisions to provide capacity to a customer, which is a stand-ready obligation to deliver energy when required by the customer. Capacity payments are generally considered lease elements as they cover the majority of available output from a facility. The allocation of contract payments between the lease and non-lease elements is made at the inception of the lease. Lease payments from such contracts are recognized as lease revenue on a straight-line basis over the lease term, whereas variable lease payments are recognized when earned.

The following table presents lease revenue from operating leases in which the Company is the lessor, recognized in *Revenue* on the Consolidated Statements of Operations for the periods indicated (in millions):

	Years Ended December 31,	
Lease Income	**2023**	**2022**
Total lease revenue	$ 490	$ 527
Less: Variable lease revenue	(65)	(49)
Total non-variable lease revenue	$ 425	$ 478

The following table presents the underlying gross assets and accumulated depreciation of operating leases included in *Property, Plant and Equipment* on the Consolidated Balance Sheets as of the periods indicated (in millions):

Lease Assets	**December 31, 2023**	**December 31, 2022**
Gross assets	$ 1,227	$ 1,319
Less: Accumulated depreciation	(182)	(139)
Net assets	$ 1,045	$ 1,180

The option to extend or terminate a lease is based on customary early termination provisions in the contract, such as payment defaults, bankruptcy, or lack of performance on energy delivery. The Company has not recognized any early terminations as of December 31, 2023. Certain leases may provide for variable lease payments based on usage or index-based (e.g., the U.S. Consumer Price Index) adjustments to lease payments.

The following table shows the future lease receipts as of December 31, 2023 for 2024 through 2028 and thereafter (in millions):

	Future Cash Receipts for	
	Sales-Type Leases	**Operating Leases**
2024	$ 34	$ 393
2025	32	394
2026	32	280
2027	32	183
2028	32	60
Thereafter	441	484
Total	603	$ 1,794
Less: Imputed interest	(296)	
Present value of total lease receipts	$ 307	

Battery Storage Lease Arrangements — The Company constructs and operates projects consisting only of a stand-alone BESS facility, as well as projects that pair a BESS with solar energy systems. These projects allow more flexibility on when to provide energy to the grid. The Company will enter into PPAs for the full output of the facility that allow customers the ability to determine when to charge and discharge the BESS. These arrangements include both lease and non-lease elements under ASC 842, with the BESS component typically constituting a sales-type lease. The Company recognized lease revenue on sales-type leases through variable payments of $3 million and $2 million and interest income of $13 million and $23 million for the years ended December 31, 2023 and 2022, respectively. During the second quarter of 2022, the Company recognized a full allowance of $20 million on a sales-type lease receivable at AES Gilbert. See Note 21—*Other Income and Expense* for further information. During the second quarter of 2023, the sales-type lease receivable and the associated allowance were written-off.

The Company recorded a loss at commencement of sales-type leases of $20 million and $5 million for the years ended December 31, 2023 and 2022, respectively. These amounts are recognized in *Other expense* in the Consolidated Statement of Operations. See Note 21—*Other Income and Expense* for further information. Effective January 1, 2022, the Company adopted ASU 2021-05 in which lessors classify and account for certain leases with primarily variable-based lease payments as operating leases. The Company adopted this standard on a prospective basis. See Note 1—*General and Summary of Significant Accounting Policies* for further information.

15. BENEFIT PLANS

Defined Contribution Plans — The Company sponsors four defined contribution plans ("the DC Plans"). Two plans cover U.S. non-union employees; one for Parent Company and certain U.S. business employees, and one for AES Ohio employees. The remaining two plans include union and non-union employees at AES Indiana and union employees at AES Ohio. The DC Plans are qualified under section 401 of the Internal Revenue Code. Most U.S. employees of the Company are eligible to participate in the appropriate plan except for those employees who are covered by a collective bargaining agreement, unless such agreement specifically provides that the employee is considered an eligible employee under a plan. Within the DC Plans, the Company provides matching contributions in addition to other non-matching contributions. Participants are fully vested in their own contributions. The Company's contributions vest over various time periods ranging from immediate up to five years. For the years ended December 31, 2023, 2022 and 2021, costs for defined contribution plans were approximately $40 million, $31 million and $26 million, respectively.

Defined Benefit Plans — Certain of the Company's subsidiaries have defined benefit pension plans covering substantially all of their respective employees ("the DB Plans"). Pension benefits are based on years of credited service, age of the participant, and average earnings. Of the 27 active DB Plans as of December 31, 2023, five are at U.S. subsidiaries and the remaining plans are at foreign subsidiaries.

The following table reconciles the Company's funded status, both domestic and foreign, as of the periods indicated (in millions):

	2023		2022	
	U.S.	Foreign	U.S.	Foreign
Change in projected benefit obligation:				
Benefit obligation as of January 1	$ 914	$ 177	$ 1,225	$ 173
Service cost	8	4	14	4
Interest cost	47	21	28	17
Plan amendments	2	—	—	—
Plan settlements	—	(1)	—	—
Benefits paid	(115)	(15)	(65)	(13)
Divestitures	—	—	—	(1)
Actuarial loss (gain)	19	(2)	(288)	(11)
Effect of foreign currency exchange rate changes	—	6	—	8
Benefit obligation as of December 31	$ 875	$ 190	$ 914	$ 177
Change in plan assets:				
Fair value of plan assets as of January 1	$ 911	$ 114	$ 1,218	$ 106
Actual return on plan assets	80	10	(250)	7
Employer contributions	8	9	8	5
Plan settlements	—	(1)	—	—
Benefits paid	(116)	(15)	(65)	(13)
Effect of foreign currency exchange rate changes	—	10	—	9
Fair value of plan assets as of December 31	$ 883	$ 127	$ 911	$ 114
Reconciliation of funded status:				
Funded status as of December 31	$ 8	$ (63)	$ (3)	$ (63)

The following table summarizes the amounts recognized on the Consolidated Balance Sheets related to the funded status of the DB Plans, both domestic and foreign, as of the periods indicated (in millions):

December 31,	2023		2022	
Amounts Recognized on the Consolidated Balance Sheets	U.S.	Foreign	U.S.	Foreign
Noncurrent assets	$ 41	$ 10	$ 34	$ 7
Accrued benefit liability—current	—	(9)	—	(8)
Accrued benefit liability—noncurrent	(33)	(64)	(37)	(62)
Net amount recognized at end of year	$ 8	$ (63)	$ (3)	$ (63)

The following table summarizes the Company's U.S. and foreign accumulated benefit obligation as of the periods indicated (in millions):

December 31,	2023		2022	
	U.S.	Foreign	U.S.	Foreign
Accumulated benefit obligation	$ 860	$ 182	$ 900	$ 170
Information for pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	$ 325	$ 180	$ 340	$ 169
Accumulated benefit obligation	316	174	333	163
Fair value of plan assets	292	107	304	98
Information for pension plans with a projected benefit obligation in excess of plan assets:				
Projected benefit obligation	$ 325	$ 180	$ 340	$ 169
Fair value of plan assets	292	107	304	98

The following table summarizes the significant weighted average assumptions used in the calculation of benefit obligation and net periodic benefit cost, both domestic and foreign, as of the periods indicated:

December 31,		2023		2022	
		U.S.	Foreign	U.S.	Foreign
Benefit Obligation:	Discount rate	5.17 %	11.14 %	5.41 %	13.23 %
	Rate of compensation increase	2.75 %	8.01 %	2.75 %	11.06 %
Periodic Benefit Cost:	Discount rate	5.41 %	13.23 % [(1)]	2.82 %	10.45 % [(1)]
	Expected long-term rate of return on plan assets	5.55 %	9.44 %	4.50 %	6.36 %
	Rate of compensation increase	2.75 %	11.06 %	2.75 %	7.76 %

(1) Includes an inflation factor that is used to calculate future periodic benefit cost, but is not used to calculate the benefit obligation.

The Company establishes its estimated long-term return on plan assets considering various factors, which include the targeted asset allocation percentages, historic returns, and expected future returns.

The measurement of pension obligations, costs, and liabilities is dependent on a variety of assumptions. These assumptions include estimates of the present value of projected future pension payments to all plan participants, taking into consideration the likelihood of potential future events such as salary increases and demographic experience. These assumptions may have an effect on the amount and timing of future contributions.

The assumptions used in developing the required estimates include the following key factors: discount rates, salary growth, retirement rates, inflation, expected return on plan assets, and mortality rates. The effects of actual results differing from the Company's assumptions are accumulated and amortized over future periods and, therefore, generally affect the Company's recognized expense in such future periods. Unrecognized gains or losses are amortized using the “corridor approach,” under which the net gain or loss in excess of 10% of the greater of the projected benefit obligation or the market-related value of the assets, if applicable, is amortized.

Sensitivity of the Company's pension funded status to the indicated increase or decrease in the discount rate and long-term rate of return on plan assets assumptions is shown below. Note that these sensitivities may be asymmetric and are specific to the base conditions at year-end 2023. They also may not be additive, so the impact of changing multiple factors simultaneously cannot be calculated by combining the individual sensitivities shown. The funded status as of December 31, 2023 is affected by the assumptions as of that date. Pension expense for 2023 is affected by the December 31, 2022 assumptions. The impact on pension expense from a one percentage point change in these assumptions is shown in the following table (in millions):

Increase of 1% in the discount rate	$ (7)
Decrease of 1% in the discount rate	8
Increase of 1% in the long-term rate of return on plan assets	(11)
Decrease of 1% in the long-term rate of return on plan assets	11

The following table summarizes the components of the net periodic benefit cost, both domestic and foreign, for the years indicated (in millions):

December 31,	2023		2022		2021	
Components of Net Periodic Benefit Cost:	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign
Service cost	$ 8	$ 4	$ 14	$ 4	$ 14	$ 6
Interest cost	47	21	28	17	24	15
Expected return on plan assets	(52)	(11)	(53)	(7)	(59)	(8)
Amortization of prior service cost	3	—	4	—	4	—
Amortization of net loss	7	—	8	1	15	3
Curtailment gain recognized	—	—	—	—	—	(17)
Total Net Periodic Benefit Cost	$ 13	$ 14	$ 1	$ 15	$ (2)	$ (1)

The following table summarizes the amounts reflected in AOCL, including AOCL attributable to noncontrolling interests, on the Consolidated Balance Sheet as of December 31, 2023, that have not yet been recognized as components of net periodic benefit cost (in millions):

December 31, 2023	Accumulated Other Comprehensive Income (Loss)	
	U.S.	Foreign
Prior service cost	$ (3)	$ 1
Unrecognized net actuarial loss	(21)	(14)
Total	$ (24)	$ (13)

The following table summarizes the Company's target allocation for 2023 and pension plan asset allocation, both domestic and foreign, as of the periods indicated:

		Target Allocations		Percentage of Plan Assets as of December 31, 2023		2022	
Asset Category		**U.S.**	**Foreign**	**U.S.**	**Foreign**	**U.S.**	**Foreign**
Mutual Funds							
	Equity securities	22%	6%	21.80 %	5.30 %	22.17 %	3.53 %
	Debt securities	78%	88%	77.60 %	89.30 %	77.28 %	92.14 %
Real estate		—%	1%	— %	0.80 %	— %	1.09 %
Other		—%	5%	0.60 %	4.60 %	0.55 %	3.24 %
Total pension assets				100.00 %	100.00 %	100.00 %	100.00 %

The U.S. DB Plans seek to achieve the following long-term investment objectives:

- maintenance of sufficient income and liquidity to pay retirement benefits and other lump sum payments;
- long-term rate of return in excess of the annualized inflation rate;
- long-term rate of return, net of relevant fees, that meets or exceeds the assumed actuarial rate; and
- long-term competitive rate of return on investments, net of expenses, that equals or exceeds various benchmark rates.

The asset allocation is reviewed periodically to determine a suitable asset allocation which seeks to manage risk through portfolio diversification and takes into account the above-stated objectives, in conjunction with current funding levels, cash flow conditions, and economic and industry trends. The following table summarizes the Company's U.S. DB Plan assets by category of investment and level within the fair value hierarchy as of the periods indicated (in millions):

		December 31, 2023				December 31, 2022			
U.S. Plans		**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Mutual Funds	Equity securities: (1)	$ —	$ 193	$ —	$ 193	$ —	$ 202	$ —	$ 202
	Debt securities: (1)	—	685	—	685	—	704	—	704
Cash and cash equivalents		5	—	—	5	5	—	—	5
	Total plan assets	$ 5	$ 878	$ —	$ 883	$ 5	$ 906	$ —	$ 911

(1) For the U.S. plans, the balances under the equity securities and debt securities categories represent investments through common collective trusts, for which the underlying investments are equity and debt securities.

The investment strategy of the foreign DB Plans seeks to maximize return on investment while minimizing risk. The assumed asset allocation has less exposure to equities in order to closely match market conditions and near term forecasts. The following table summarizes the Company's foreign DB plan assets by category of investment and level within the fair value hierarchy as of the periods indicated (in millions):

		December 31, 2023				December 31, 2022			
Foreign Plans		**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Equity Securities	Private equity	$ —	$ —	$ 2	$ 2	$ —	$ —	$ 1	$ 1
Mutual Funds	Equity securities: (1)	—	5	—	5	—	3	—	3
	Debt securities: (1)	40	73	—	113	35	70	—	105
Real estate	Real estate	—	—	1	1	—	—	1	1
Other	Other assets	1	3	2	6	1	2	1	4
	Total plan assets	$ 41	$ 81	$ 5	$ 127	$ 36	$ 75	$ 3	$ 114

(1) Mutual funds categorized as debt securities and equity securities consist of mutual funds for which debt securities and equity securities are the primary underlying investment.

The following table summarizes the estimated cash flows for U.S. and foreign expected employer contributions and expected future benefit payments, both domestic and foreign (in millions):

	U.S.	Foreign
Expected employer contribution in 2024	$ 8	$ 11
Expected benefit payments for fiscal year ending:		
2024	63	19
2025	63	17
2026	64	18
2027	64	20
2028	66	21
2029 - 2033	318	125

16. REDEEMABLE STOCK OF SUBSIDIARIES

The following table is a reconciliation of changes in redeemable stock of subsidiaries (in millions):

December 31,	2023	2022
Balance at the beginning of the period	$ 1,321	$ 1,257
Net loss	(59)	(87)
Other comprehensive income	1	40
Distributions to holders of redeemable stock of subsidiaries	(62)	(64)
Acquisitions of redeemable stock of subsidiaries	—	(60)
Contributions from holders of redeemable stock of subsidiaries	163	67
Sales of redeemable stock of subsidiaries	100	168
Balance at the end of the period	$ 1,464	$ 1,321

The following table summarizes the Company's redeemable stock of subsidiaries balances as of the periods indicated (in millions):

December 31,	2023	2022
IPALCO common stock	$ 773	$ 782
AES Clean Energy Development common stock	544	436
AES Clean Energy Development tax equity partnerships	129	86
Potengi common and preferred stock	18	17
Total redeemable stock of subsidiaries	$ 1,464	$ 1,321

AES Clean Energy Development Tax Equity Partnerships — The majority of solar projects in the U.S. have been financed with tax equity structures, in which tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes, that vary over the life of the projects. In some cases, these agreements contain certain partnership rights, though not currently in effect, that would enable the tax equity investor to exit in the future. As a result, the noncontrolling ownership interest is considered temporary equity. The redemption features of these tax equity partnership agreements are typically contingent upon the underlying assets being placed in service by a guaranteed date. The Company has concluded it is probable that these projects will be placed in service by the guaranteed dates. Therefore, the noncontrolling ownership interests are not probable of becoming redeemable and subsequent adjustments to the carrying value were not required.

In 2023 and 2022, AES Clean Energy Development, through multiple transactions, sold noncontrolling interests in project companies to tax equity investors, resulting in increases to *Redeemable stock of subsidiaries* of $100 million and $157 million, respectively. AES Clean Energy Development is reported in the Renewables SBU reportable segment.

IPALCO — In December 2022, CDPQ made equity capital contributions of $77 million as part of a capital call to raise proceeds for AES Indiana's TDSIC and replacement generation project. The Company and CDPQ made capital contributions on a proportional share basis; therefore, the capital calls did not change either party's ownership interests in IPALCO. The Company has concluded that the likelihood of an event that would allow CDPQ to redeem its interest under the terms of the shareholder agreement is remote. Therefore, the noncontrolling ownership interest is not probable of becoming redeemable and subsequent adjustments to the carrying value were not required. IPALCO is reported in the Utilities SBU reportable segment.

AES Indiana — In December 2022, AES Indiana redeemed all of its outstanding preferred shares for $60 million. The preferred shares were retired upon redemption as there is no intention for the shares to be reissued. AES Indiana is reported in the Utilities SBU reportable segment.

Potengi — In March 2022, Tucano Holding I ("Tucano"), a subsidiary of AES Brasil, issued new shares in the Potengi wind development project. BRF S.A. ("BRF") acquired shares representing 24% of the equity in the project for $12 million, reducing the Company's indirect ownership interest in Potengi to 35.5%. As the Company maintained control after the transaction, Potengi continues to be consolidated by the Company. As part of the transaction, BRF was given an option to sell its entire ownership interest at the conclusion of the PPA term and therefore the noncontrolling ownership interest is considered temporary equity. Any subsequent changes in the redemption value of the exit rights will be recognized against permanent equity in accordance with ASC 480-10-S99, as it is probable that the shares will become redeemable. Potengi is reported in the Renewables SBU reportable segment.

17. EQUITY

Equity Units

In March 2021, the Company issued 10,430,500 Equity Units with a total notional value of $1,043 million. Each Equity Unit has a stated amount of $100 and was initially issued as a Corporate Unit, consisting of a forward stock purchase contract ("2024 Purchase Contracts") and a 10% undivided beneficial ownership interest in one share of 0% Series A Cumulative Perpetual Convertible Preferred Stock, issued without par and with a liquidation preference of $1,000 per share ("Series A Preferred Stock").

The Company concluded that the Equity Units should be accounted for as one unit of account based on the economic linkage between the 2024 Purchase Contracts and the Series A Preferred Stock, as well as the Company's assessment of the applicable accounting guidance relating to combining freestanding instruments. The Equity Units represent mandatorily convertible preferred stock. Accordingly, the shares associated with the combined instrument are reflected in diluted earnings per share using the if-converted method.

In conjunction with the issuance of the Equity Units, the Company received approximately $1 billion in proceeds, net of underwriting costs and commissions, before offering expenses. The proceeds for the issuance of 1,043,050 shares were attributed to the Series A Preferred Stock for $838 million and $205 million for the present value of the quarterly payments due to holders of the 2024 Purchase Contracts ("Contract Adjustment Payments"). The proceeds were used for the development of the AES renewable businesses, U.S. utility businesses, LNG infrastructure, and for other developments determined by management.

The Series A Preferred Stock does not bear any dividends and the liquidation preference of the convertible preferred stock does not accrete. The Series A Preferred Stock has no maturity date and will remain outstanding unless converted by holders or redeemed by the Company. Holders of the preferred shares have limited voting rights. The Series A Preferred Stock was pledged as collateral to support holders' purchase obligations under the 2024 Purchase Contracts. The 2024 Purchase Contracts obligated the holders to purchase, on February 15, 2024, for a price of $100 in cash, a maximum number of 57,467,883 shares of the Company's common stock (subject to customary anti-dilution adjustments). The initial settlement rate determining the number of shares that each holder must purchase cannot exceed the maximum settlement rate and was determined over a market value averaging period preceding February 15, 2024. If the applicable market value of the Company's common stock was less than or equal to the reference price, the settlement rate would be the maximum settlement rate; and if the applicable market value of common stock was greater than the reference price, the settlement rate would be a number of shares of the Company's common stock equal to $100 divided by the applicable market value.

The initial maximum settlement rate of 3.864 was calculated using an initial reference price of $25.88, equal to the last reported sale price of the Company's common stock on March 4, 2021. As of December 31, 2023, due to the customary anti-dilution provisions, the maximum settlement rate was 3.8809, equivalent to a reference price of $25.77. On February 15, 2024, the Series A Preferred Stock was tendered to satisfy the Purchase Contract's settlement price and the Corporate Units were converted into shares of the Company's common stock at a settlement rate of 3.8859, equivalent to a reference price of $25.73. The Series A Preferred Stock was cancelled upon conversion.

The Company paid Contract Adjustment Payments to the holders of the 2024 Purchase Contracts at a rate of 6.875% per annum, payable quarterly in arrears on February 15, May 15, August 15, and November 15, commencing on May 15, 2021. The $205 million present value of the Contract Adjustment Payments at inception reduced the Series A Preferred Stock. As each quarterly Contract Adjustment Payment was made, the related liability was reduced and the difference between the cash payment and the present value accreted to interest expense, approximately $5 million over the three-year term. As of December 31, 2023, the present value of the Contract Adjustment Payments was $18 million. The final Contract Adjustment Payments were made on February 15, 2024.

Equity Transactions with Noncontrolling Interests

U.S. Renewable Energy Tax Equity Partnerships — The majority of solar projects in the U.S. have been financed with tax equity structures, in which tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes, that vary over the life of the projects.

In 2023, 2022, and 2021, AES Clean Energy Development and AES Renewable Holdings, through multiple transactions, sold noncontrolling interests in project companies to tax equity investors, resulting in the following increases to NCI (in millions):

Business	2023	2022	2021
AES Clean Energy Development	$ 1,039	$ 230	$ —
AES Renewable Holdings	124	88	127

In the third quarter of 2023, AES Renewable Holdings completed buyouts of tax equity partners at Buffalo Gap I, Buffalo Gap II and six other project companies, resulting in a decrease to NCI of $45 million and an increase to additional paid-in capital of $34 million. AES Clean Energy Development and AES Renewable Holdings are reported in the Renewables SBU reportable segment.

In December 2023, AES Indiana sold a noncontrolling interest in the Hardy Hills solar project to a tax equity investor, resulting in a $79 million increase to NCI. AES Indiana is reported in the Utilities SBU reportable segment.

Chile Renovables — In July 2021, AES Andes completed the sale of a 49% ownership interest in Chile Renovables SpA (“Chile Renovables”), a subsidiary which owns the Los Cururos wind facility, to Global Infrastructure Management, LLC (“GIP”) for $53 million. AES Andes retained a 51% ownership interest in Chile Renovables and the transaction decreased the Company’s indirect ownership in the subsidiary to 34%.

Under its renewable partnership agreement with GIP, AES Andes will contribute a specified pipeline of renewable development projects to Chile Renovables as the projects reach commercial operations, and GIP may make additional contributions to maintain its 49% ownership interest. During 2022 and 2023, AES Andes completed sales of the following projects to Chile Renovables (in millions):

Business	Transaction Period	Sale Price	Increase to Noncontrolling Interests	Increase (Decrease) to Additional Paid-In Capital
Andes Solar 2a	January 2022	$ 37	$ 28	$ 9
Los Olmos	June 2022	80	68	12
Campo Lindo	September 2023	50	59	(9)
Bolero	November 2023	58	57	1
Andes Solar 2b	December 2023	156	145	11

In December 2023, Chile Renovables issued $275 million of preferred shares to GIP, the proceeds of which will be used to fund the development of a additional pipeline of renewables projects. As each project reaches commercial operations, the preferred shares will convert to common stock and GIP may make additional contributions to maintain its 49% ownership interest.

As the Company maintained control after these transactions, Chile Renovables continues to be consolidated by the Company within the Energy Infrastructure SBU reportable segment.

AES Dominicana — In December 2023, the Company completed the sale of a 20% ownership interest in AES Dominicana for $192 million. AES Dominicana consists of five operating subsidiaries: Andres, Los Mina, Bayasol, Santanasol, and Agua Clara. This transaction decreased the Company's economic interest to 65% and resulted in a $74 million increase in Parent Company Stockholder's Equity due to an increase in additional paid-in-capital of $73 million and the reclassification of accumulated other comprehensive losses from AOCL to NCI of $1 million. As the Company maintained control after the sale, AES Dominicana continues to be consolidated by the Company. Andres and Los Mina are included within the Energy Infrastructure SBU reportable segment and Bayasol, Santanasol, and Aqua Clara are included within the Renewables SBU reportable segment.

Colon — In September 2021, the Company acquired the remaining 49.9% minority ownership interest in Colon to become its sole owner. The purchase price was paid over two installments in November 2021 and December 2023. This transaction resulted in a $12 million decrease in Parent Company Stockholders' Equity due to a decrease in additional paid-in-capital of $8 million and the reclassification of accumulated other comprehensive losses from *Redeemable stock of subsidiaries* to AOCL of $4 million.

In December 2023, the Company completed the sale a 35% ownership interest in Colon for $146 million, which decreased the Company's economic interest to 65%. This transaction resulted in a $43 million increase in Parent Company Stockholder's Equity due to an increase in additional paid-in-capital of $31 million and the reclassification of accumulated other comprehensive losses from AOCL to NCI of $12 million. As the Company maintained control after the sale, Colon continues to be consolidated by the Company within the Energy Infrastructure SBU reportable segment.

AES Renewable Holdings — In December 2023, AES Renewable Holdings issued preferred shares in a portfolio of operating assets ("OpCo 1") to HASI for total proceeds of $143 million. As the Company maintained control after the transaction, AES Renewable Holdings continues to be consolidated by the Company within the Renewables SBU reportable segment.

AES Panama — In September 2023, AES Latin America completed the sale of its interest in the Grupo Energía Gas Panamá joint venture to AES Panama, a 49%-owned consolidated subsidiary. See Note 8—*Investments in and Advances to Affiliates* for further information. As a result of the transaction, AES Panama received $42 million from noncontrolling interest holders and the Company reclassified accumulated other comprehensive income from AOCL to NCI of $23 million. AES Panama is reported in the Renewables SBU reportable segment however the investment in Grupo Energía Gas Panamá is reported in the Energy Infrastructure SBU reportable segment.

Southland Energy — In December 2022, the Company completed the sale of a 14.9% ownership interest in the Southland Energy assets for $157 million, which decreased the Company's economic interest to 50.1%. This transaction resulted in a $91 million increase in Parent Company Stockholder's Equity due to an increase in additional paid-in-capital of $94 million, net of tax and transaction costs, partially offset by the reclassification of accumulated other comprehensive income from AOCL to NCI of $3 million. As the Company maintained control after the sale, Southland Energy continues to be consolidated by the Company. The CCGT units and interconnected battery-based energy storage facilities are included within the Energy Infrastructure SBU and Renewables SBU reportable segments, respectively.

AES Brasil — In August 2020, AES Holdings Brasil Ltda. ("AHB") committed to migrate AES Tietê to the Novo Mercado, which is a listing segment of the Brazilian stock exchange that requires equity capital to be composed only of common shares. On December 18, 2020, the AES Tietê board approved a proposal for the corporate reorganization and exchange of shares issued by AES Tietê with newly issued shares of AES Brasil, a formerly wholly-owned entity of AES Tietê, with the intent to list AES Brasil on Novo Mercado as the 100% shareholder of AES Tietê. The reorganization and the exchange of shares was completed on March 26, 2021, and the shares issued by AES Brasil started trading on Novo Mercado on March 29, 2021. The Company maintains majority representation on AES Brasil's board of directors.

Through multiple transactions in 2021, AHB acquired an additional 1.6% ownership in AES Brasil for $17 million. These transactions increased the Company's economic interest in AES Brasil to 45.7% and resulted in a $13 million decrease in Parent Company Stockholder's Equity due to a decrease in additional paid-in-capital of $6 million and the reclassification of accumulated other comprehensive losses from NCI to AOCL of $7 million.

In October 2021, AES Brasil concluded a follow-on offering for the issuance of 93 million newly issued shares, which further increased the Company's indirect beneficial interest in AES Brasil to 46.7% and resulted in a $7 million increase in Parent Company Stockholder's Equity due to an increase in additional paid-in capital.

In September 2022, AES Brasil commenced a private placement offering for its existing shareholders to subscribe for up to 116 million newly issued shares, of which 107 million were subscribed. AHB and noncontrolling interest holders subscribed for 54 million and 53 million shares, respectively, thereby increasing AES' indirect beneficial interest in AES Brasil to 47.4% and resulting in additional capital contributions from noncontrolling interest holders of $98 million, an increase in additional paid-in capital of $10 million, and the reclassification of accumulated other comprehensive losses from NCI to AOCL of $3 million. AES Brasil is reported in the Renewables SBU reportable segment.

Guaimbê Holding — In April 2021, Guaimbê Solar Holding S.A ("Guaimbê Holding"), a subsidiary of AES Brasil which wholly owned the Guaimbê solar complex and the Alto Sertão II wind facility, issued preferred shares representing 19.9% ownership in the subsidiary for total proceeds of $158 million. The transaction decreased the Company's indirect ownership interest in the operational entities from 45.3% to 36.3%.

In January 2022, the Ventus wind complex and AGV solar complex were incorporated by Guaimbê Holding. Guaimbê Holding issued additional preferred shares representing 3.5% ownership in the subsidiary for total proceeds of $63 million. The transaction further decreased the Company's indirect ownership interest to 35.8%. As the Company maintained control after these transactions, Guaimbê Holding continues to be consolidated by the Company within the Renewables SBU reportable segment.

AES Andes — On December 29, 2020, AES Andes commenced a preemptive rights offering for its existing shareholders to subscribe for up to 1.98 billion of newly issued shares to fund its renewable growth program. The period ended on February 5, 2021 and Inversiones Cachagua SpA, an AES subsidiary, subscribed for 1.35 billion shares at a cost of $205 million, increasing AES' indirect beneficial interest in AES Andes from 67% to 67.1%. The noncontrolling interest holders subscribed for 629 million shares, resulting in additional capital contributions of $94 million.

In January 2022, Cachagua completed a tender offer for the shares of AES Andes held by minority shareholders for $522 million, net of transaction costs. Upon completion, AES' indirect beneficial interest in AES Andes increased from 67.1% to 98.1%. Through multiple transactions in 2022 following the tender offer, Cachagua acquired an additional 1.3% ownership in AES Andes for $22 million, further increasing AES' indirect beneficial interest to 99.4% The tender offer and these follow-on transactions resulted in a $172 million decrease to Parent Company Stockholder's Equity due to a decrease in additional paid-in capital of $96 million and the reclassification of accumulated other comprehensive losses from NCI to AOCL of $76 million. AES Andes is reported in the Energy Infrastructure SBU reportable segment.

The following table summarizes the net income (loss) attributable to The AES Corporation and all transfers (to) from noncontrolling interests for the periods indicated (in millions):

December 31,	**2023**	**2022**	**2021**
Net income (loss) attributable to The AES Corporation	$ 249	$ (546)	$ (409)
Transfers from noncontrolling interest:			
Increase (decrease) in The AES Corporation's paid-in capital for sale of subsidiary shares	85	78	(7)
Increase (decrease) in The AES Corporation's paid-in-capital for purchase of subsidiary shares	24	(78)	(9)
Net transfers (to) from noncontrolling interest	109	—	(16)
Change from net income (loss) attributable to The AES Corporation and transfers (to) from noncontrolling interests	$ 358	$ (546)	$ (425)

Deconsolidations

Alto Maipo — In November 2021, Alto Maipo SpA filed a voluntary petition for relief under Chapter 11 of the U.S. Bankruptcy Code. The Company determined it no longer had control over Alto Maipo and deconsolidated the business, which increased Parent Company Stockholder's Equity by $182 million due to the disposition of $177 million of accumulated other comprehensive losses and $5 million of accumulated deficit. See Note 24—*Held-for-Sale and Dispositions* for further information.

Accumulated Other Comprehensive Loss — The changes in AOCL by component, net of tax and noncontrolling interests, for the periods indicated were as follows (in millions):

	Foreign currency translation adjustment, net	Derivative gains (losses), net	Unfunded pension obligations, net	Total
Balance at December 31, 2021	$ (1,734)	$ (456)	$ (30)	$ (2,220)
Other comprehensive income (loss) before reclassifications	(37)	645	10	618
Amount reclassified to earnings	—	44	—	44
Other comprehensive income (loss)	(37)	689	10	662
Reclassification from NCI due to share sales and repurchases	(57)	(22)	(3)	(82)
Balance at December 31, 2022	$ (1,828)	$ 211	$ (23)	$ (1,640)
Other comprehensive income (loss) before reclassifications	136	55	(3)	188
Amount reclassified to earnings	—	(52)	—	(52)
Other comprehensive income (loss)	136	3	(3)	136
Reclassification from NCI due to share sales	—	(10)	—	(10)
Balance at December 31, 2023	$ (1,692)	$ 204	$ (26)	$ (1,514)

Reclassifications out of AOCL are presented in the following table. Amounts for the periods indicated are in millions and those in parenthesis indicate debits to the Consolidated Statements of Operations.

Details About AOCL Components	Affected Line Item in the Consolidated Statements of Operations	December 31, 2023	2022	2021
Foreign currency translation adjustments, net				
	Gain on disposal and sale of business interests	$ —	$ —	$ (3)
	Net income attributable to The AES Corporation	$ —	$ —	$ (3)
Derivative gains (losses), net				
	Non-regulated revenue	$ (8)	$ (1)	$ (1)
	Non-regulated cost of sales	(3)	(1)	1
	Interest expense	17	(58)	(85)
	Gain (loss) on disposal and sale of business interests	33	—	(362)
	Asset impairment expense	—	(16)	(13)
	Foreign currency transaction losses	(3)	2	(15)
	Income from continuing operations before taxes and equity in earnings of affiliates	36	(74)	(475)
	Income tax benefit (expense)	9	9	105
	Net equity in losses of affiliates	28	6	(17)
	Net income (loss)	73	(59)	(387)
	Less: Net loss (income) attributable to noncontrolling interests and redeemable stock of subsidiaries	(21)	15	133
	Net income (loss) attributable to The AES Corporation	$ 52	$ (44)	$ (254)
Amortization of defined benefit pension actuarial losses, net				
	Non-regulated cost of sales	$ —	$ (1)	$ (1)
	Other expense	—	(1)	(3)
	Income from continuing operations before taxes and equity in earnings of affiliates	—	(2)	(4)
	Income tax benefit (expense)	—	1	3
	Net income (loss)	—	(1)	(1)
	Less: Net income attributable to noncontrolling interests and redeemable stock of subsidiaries	—	1	—
	Net income (loss) attributable to The AES Corporation	$ —	$ —	$ (1)
Total reclassifications for the period, net of income tax and noncontrolling interests		$ 52	$ (44)	$ (258)

Common Stock Dividends — The Parent Company paid dividends of $0.1659 per outstanding share to its common stockholders during the first, second, third, and fourth quarters of 2023 for dividends declared in December 2022, February 2023, July 2023, and October 2023, respectively.

On December 8, 2023, the Board of Directors declared a quarterly common stock dividend of $0.1725 per share payable on February 15, 2024 to shareholders of record at the close of business on February 1, 2024.

Stock Repurchase Program — No shares were repurchased in 2023. The cumulative repurchases from the commencement of the Stock Repurchase Program in July 2010 through December 31, 2023 totaled 154.3 million shares for a total cost of $1.9 billion, at an average price per share of $12.12 (including a nominal amount of commissions). As of December 31, 2023, $264 million remained available for repurchase under the Stock Repurchase Program.

The common stock repurchased has been classified as treasury stock and accounted for using the cost method. A total of 149,358,357 and 150,046,537 shares were held as treasury stock at December 31, 2023 and December 31, 2022, respectively. Restricted stock units under the Company's employee benefit plans are issued from treasury stock. The Company has not retired any common stock repurchased since it began the Stock Repurchase Program in July 2010.

18. SEGMENTS AND GEOGRAPHIC INFORMATION

The segment reporting structure uses the Company's management reporting structure as its foundation to reflect how the Company manages the businesses internally. In our 2022 Form 10-K, the management reporting structure and the Company's reportable segments were mainly organized by geographic regions. In March 2023, we announced internal management changes as a part of our ongoing strategy to align our business to meet our customers' needs and deliver on our major strategic objectives. The management reporting structure is now composed of four SBUs, mainly organized by technology, led by our President and Chief Executive Officer. Using the accounting guidance on segment reporting, the Company determined that its four operating segments are aligned with its four reportable segments corresponding to its SBUs. All prior period results have been retrospectively revised to reflect the new segment reporting structure.

- *Renewables* — Solar, wind, energy storage, and hydro generation facilities;
- *Utilities* — AES Indiana, AES Ohio and AES El Salvador regulated utilities and their generation facilities;
- *Energy Infrastructure* — Natural gas, LNG, coal, pet coke, diesel and oil generation facilities, and our businesses in Chile, which have a mix of generation sources, including renewables, that are pooled to service our existing PPAs; and
- *New Energy Technologies* — Green hydrogen initiatives and investments in Fluence, Uplight, 5B, and other new and innovative energy technology businesses.

Our Renewables, Utilities, and Energy Infrastructure SBUs participate in our generation business line, in which we own and/or operate power plants to generate and sell power to customers, such as utilities, industrial users, and other intermediaries. Our Utilities SBU participates in our utilities business line, in which we own and/or operate utilities to generate or purchase, distribute, transmit and sell electricity to end-user customers in the residential, commercial, industrial, and governmental sectors within a defined service area. In certain circumstances, our utilities also generate and sell electricity on the wholesale market. Our New Energy Technologies SBU includes investments in new and innovative technologies to support leading-edge greener energy solutions.

Included in "Corporate and Other" are the results of the AES self-insurance company, corporate overhead costs which are not directly associated with the operations of our four reportable segments, and certain intercompany charges such as self-insurance premiums which are fully eliminated in consolidation.

During the first quarter of 2023, management began assessing operational performance and making resource allocation decisions using Adjusted EBITDA. Therefore, the Company uses Adjusted EBITDA as its primary segment performance measure. Adjusted EBITDA, a non-GAAP measure, is defined by the Company as earnings before interest income and expense, taxes, depreciation and amortization, adjusted for the impact of NCI and interest, taxes, depreciation and amortization of our equity affiliates, and adding back interest income recognized under service concession arrangements; excluding gains or losses of both consolidated entities and entities accounted for under the equity method due to (a) unrealized gains or losses related to derivative transactions and equity securities; (b) unrealized foreign currency gains or losses; (c) gains, losses, benefits and costs associated with dispositions and acquisitions of business interests, including early plant closures, and gains and losses recognized at commencement of sales-type leases; (d) losses due to impairments; (e) gains, losses and costs due to the early retirement of debt; and (f) net gains at Angamos, one of our businesses in the Energy Infrastructure SBU, associated with the early contract terminations with Minera Escondida and Minera Spence.

The Company has concluded Adjusted EBITDA better reflects the underlying business performance of the Company and is the most relevant measure considered in the Company's internal evaluation of the financial performance of its segments. Additionally, given its large number of businesses and overall complexity, the Company concluded that Adjusted EBITDA is a more transparent measure that better assists investors in determining which businesses have the greatest impact on the Company's results.

Revenue and Adjusted EBITDA are presented before inter-segment eliminations, which includes the effect of intercompany transactions with other segments except for charges for certain management fees and the write-off of intercompany balances, as applicable. All intra-segment activity has been eliminated within the segment. Inter-segment activity has been eliminated within the total consolidated results.

The following tables present financial information by segment for the periods indicated (in millions):

	Total Revenue		
Year Ended December 31,	**2023**	**2022**	**2021**
Renewables SBU	$ 2,339	$ 1,893	$ 1,562
Utilities SBU	3,495	3,617	2,944
Energy Infrastructure SBU	6,836	7,204	6,702
New Energy Technologies SBU	76	3	7
Corporate and Other	138	116	108
Eliminations	(216)	(216)	(182)
Total Revenue	$ 12,668	$ 12,617	$ 11,141

Reconciliation from Net Income (Loss):	Adjusted EBITDA		
Year Ended December 31,	**2023**	**2022**	**2021**
Net loss	$ (182)	$ (505)	$ (951)
Income tax expense (benefit)	261	265	(133)
Interest expense	1,319	1,117	911
Interest income	(551)	(389)	(298)
Depreciation and amortization	1,128	1,053	1,056
EBITDA	$ 1,975	$ 1,541	$ 585
Less: Income from discontinued operations	(7)	—	(4)
Less: Adjustment for noncontrolling interests and redeemable stock of subsidiaries [1]	(552)	(704)	(47)
Less: Income tax expense (benefit), interest expense (income) and depreciation and amortization from equity affiliates	130	126	123
Interest income recognized under service concession arrangements	71	77	82
Unrealized derivative and equity securities losses (gains)	34	131	(4)
Unrealized foreign currency losses	301	42	14
Disposition/acquisition losses (gains)	(79)	40	863
Impairment losses	877	1,658	1,153
Loss on extinguishment of debt	62	20	71
Net gains from early contract terminations at Angamos	—	—	(256)
Adjusted EBITDA	$ 2,812	$ 2,931	$ 2,580

(1) The allocation of earnings and losses to tax equity investors from both consolidated entities and equity affiliates is removed from Adjusted EBITDA.

	Adjusted EBITDA		
Year Ended December 31,	**2023**	**2022**	**2021**
Renewables SBU	$ 645	$ 605	$ 545
Utilities SBU	678	612	633
Energy Infrastructure SBU	1,531	1,836	1,494
New Energy Technologies SBU	(62)	(116)	(77)
Corporate and Other	22	(19)	(20)
Eliminations	(2)	13	5
Total Adjusted EBITDA	$ 2,812	$ 2,931	$ 2,580

The Company uses long-lived assets as its measure of segment assets. Long-lived assets includes amounts recorded in *Property, plant and equipment, net* and right-of-use assets for operating leases recorded in *Other noncurrent assets* on the Consolidated Balance Sheets.

Year Ended December 31,	Long-Lived Assets 2023	2022	2021
Renewables SBU	$ 15,735	$ 9,533	$ 6,353
Utilities SBU	7,166	6,311	6,027
Energy Infrastructure SBU	7,414	7,532	7,778
New Energy Technologies SBU	14	2	4
Corporate and Other	9	17	21
Long-Lived Assets	30,338	23,395	20,183
Current assets	6,649	7,643	5,356
Investments in and advances to affiliates	941	952	1,080
Debt service reserves and other deposits	194	177	237
Goodwill	348	362	1,177
Other intangible assets	2,243	1,841	1,450
Deferred income taxes	396	319	409
Other noncurrent assets, excluding right-of-use assets for operating leases	2,879	3,674	1,911
Noncurrent held-for-sale assets	811	—	1,160
Total Assets	$ 44,799	$ 38,363	$ 32,963

Year Ended December 31,	Depreciation and Amortization 2023	2022	2021	Capital Expenditures 2023	2022	2021
Renewables SBU	$ 338	$ 260	$ 222	$ 5,759	$ 2,972	$ 721
Utilities SBU	400	376	361	1,374	859	544
Energy Infrastructure SBU	381	404	458	585	742	847
New Energy Technologies SBU	1	2	1	5	—	—
Corporate and Other	8	11	14	10	11	28
Total	$ 1,128	$ 1,053	$ 1,056	$ 7,733	$ 4,584	$ 2,140

Year Ended December 31,	Interest Income 2023	2022	2021	Interest Expense 2023	2022	2021	Net Equity in Earnings (Losses) of Affiliates 2023	2022	2021
Renewables SBU	$ 181	$ 131	$ 55	$ 326	$ 236	$ 200	$ 41	$ 28	$ 63
Utilities SBU	12	8	5	243	234	218	5	6	3
Energy Infrastructure SBU	337	246	236	534	488	422	6	9	(4)
New Energy Technologies SBU	2	—	—	—	—	—	(84)	(114)	(86)
Corporate and Other	19	4	2	216	159	71	—	—	—
Total	$ 551	$ 389	$ 298	$ 1,319	$ 1,117	$ 911	$ (32)	$ (71)	$ (24)

The following table presents information, by country, about the Company's consolidated operations for each of the three years ended December 31, 2023, 2022, and 2021, and as of December 31, 2023 and 2022 (in millions). Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

Year Ended December 31,	Total Revenue 2023	2022	2021	Long-Lived Assets 2023	2022
United States [1]	$ 4,439	$ 4,093	$ 3,531	$ 19,750	$ 13,833
Non-U.S.:					
Chile	1,932	2,064	2,297	3,018	2,730
Dominican Republic	1,400	1,591	1,087	1,098	1,013
El Salvador	935	902	792	442	395
Colombia	706	417	383	390	308
Brazil	697	560	471	2,482	1,811
Panama	644	678	595	1,910	1,880
Mexico	536	595	471	271	409
Bulgaria	528	790	700	483	487
Argentina	407	501	390	431	461
Vietnam [2]	344	323	320	—	1
Jordan	97	102	98	39	41
Other Non-U.S.	3	1	6	24	26
Total Non-U.S.	8,229	8,524	7,610	10,588	9,562
Total	$ 12,668	$ 12,617	$ 11,141	$ 30,338	$ 23,395

(1) Includes Puerto Rico revenues of $269 million, $293 million, and $311 million for the years ended December 31, 2023, 2022, and 2021, respectively, and long-lived assets of $145 million and $96 million as of December 31, 2023 and 2022, respectively.

(2) The Mong Duong 2 power project is operated under a BOT contract. Future expected payments for the construction performance obligation were recognized in *Other noncurrent assets* on the Consolidated Balance Sheets as of December 31, 2022. The Mong Duong assets were classified as held-for-sale as of December 31, 2023. See Note 20—*Revenue* and Note 24—*Held-for-Sale and Dispositions* for further information.

19. SHARE-BASED COMPENSATION

RESTRICTED STOCK

Restricted Stock Units — The Company issues RSUs under its long-term compensation plan. The RSUs are generally granted based upon a percentage of the participant's base salary. Most RSUs have a three-year vesting period and vest evenly in annual increments over that period. In all circumstances, RSUs granted by AES do not entitle the holder the right, or obligate AES, to settle the RSU in cash or other assets of AES.

For the years ended December 31, 2023, 2022, and 2021, RSUs issued had a grant date fair value equal to the closing price of the Company's stock on the grant date. The Company does not discount the grant date fair values to reflect any post-vesting restrictions. RSUs granted to employees during the years ended December 31, 2023, 2022, and 2021 had grant date weighted average fair values per RSU of $22.33, $20.92, and $26.46, respectively.

The 2021, 2022, and 2023 RSUs awarded to certain executives have a performance condition related to the achievement of environmental and social goals for the three-year periods ending December 31, 2023, December 31, 2024, and December 31, 2025, respectively. This performance condition can adjust the final number of units that vest to increase or decrease by up to 15% of the total units for all three years. The adjustment will be reflected in the number of units that vest at the end of the three-year performance period.

The following table summarizes the components of the Company's stock-based compensation related to its employee RSUs recognized in the Company's consolidated financial statements (in millions):

December 31,	2023	2022	2021
RSU expense before income tax	$ 16	$ 16	$ 12
Tax benefit	(3)	(2)	(2)
RSU expense, net of tax	$ 13	$ 14	$ 10
Total value of RSUs converted [1]	$ 10	$ 8	$ 13
Total fair value of RSUs vested	$ 15	$ 13	$ 10

[1] Amount represents fair market value on the date of conversion.

Cash was not used to settle RSUs for the years ended December 31, 2023, 2022, and 2021. In the year ended December 31, 2023, $1 million of compensation cost was capitalized as part of the cost of an asset. In the years ended December 31, 2022 and 2021, no compensation cost was capitalized as part of the cost of an asset. As of December 31, 2023, total unrecognized compensation cost related to RSUs of $29 million is expected to be recognized over a weighted average period of approximately 1.9 years. There were no modifications to RSU awards during the year ended December 31, 2023.

A summary of the activity of RSUs for the year ended December 31, 2023 follows (RSUs in thousands):

	RSUs	Weighted Average Grant Date Fair Values	Weighted Average Remaining Vesting Term
Nonvested at December 31, 2022	1,701	$ 23.22	
Vested	(632)	23.04	
Forfeited and expired	(255)	24.32	
Granted	1,229	22.33	
Nonvested at December 31, 2023	2,043	$ 22.60	1.75
Expected to vest at December 31, 2023	1,894	$ 22.68	

The Company initially recognizes compensation cost on the estimated number of instruments for which the requisite service is expected to be rendered. In 2023, AES has estimated a weighted average forfeiture rate of 6.14% for RSUs granted in 2023. This estimate will be revised if subsequent information indicates that the actual number of instruments forfeited is likely to differ from previous estimates. Based on the estimated forfeiture rate, the Company expects to expense $26 million on a straight-line basis over a weighted average period of three years.

The following table summarizes the RSUs that vested and were converted during the periods indicated (RSUs in thousands):

Year Ended December 31,	2023	2022	2021
RSUs vested during the year	632	576	634
RSUs converted during the year, net of shares withheld for taxes	407	380	452
Shares withheld for taxes	225	196	182

OTHER SHARE BASED COMPENSATION

The Company has three other share-based award programs. The Company has recorded expense of $2 million, $23 million, and $14 million for 2023, 2022, and 2021, respectively, related to these programs.

Performance Stock Units — In 2021, 2022, and 2023, the Company issued PSUs to officers under its long-term compensation plan. PSUs are stock units which include performance conditions. For 2021, 2022, and 2023, performance conditions are based on the Company's Parent Free Cash Flow target. The performance conditions determine the vesting and final share equivalent per PSU and can result in earning an award payout range of 0% to 200%, depending on the achievement. The Company believes it is probable that the performance condition will be met and will continue to be evaluated throughout the performance period. In all circumstances, PSUs granted by AES do not entitle the holder the right, or obligate AES, to settle the stock units in cash or other assets of AES.

Performance Cash Units — In 2021, 2022, and 2023, the Company issued PCUs to its officers under its long-term compensation plan. The value for the 2021, 2022, and 2023 units is dependent on the market condition of total stockholder return on AES common stock as compared to the total stockholder return of the Standard and Poor's 500 Utilities Sector Index, Standard and Poor's 500 Index, and MSCI Emerging Markets Latin America Index over a three-year measurement period. Since PCUs are settled in cash, they qualify for liability accounting and periodic measurement is required.

Stock options — In the past, AES granted options to non-employee directors to purchase shares of common stock at a price equal to 100% of the market price at the date the option was granted. AES has not granted options since 2021. All stock options are fully vested and have a contractual term of 10 years. In all circumstances, stock options granted by AES do not entitle the holder the right, or oblige AES, to settle the stock options in cash or other assets of AES.

20. REVENUE

The following table presents our revenue from contracts with customers and other revenue for the periods indicated (in millions):

	Year Ended December 31, 2023					
	Renewables SBU	Utilities SBU	Energy Infrastructure SBU	New Energy Technologies SBU	Corporate, Other and Eliminations	Total
Non-Regulated Revenue						
Revenue from contracts with customers	$ 2,198	$ 68	$ 6,181	$ 75	$ (77)	$ 8,445
Other non-regulated revenue [1]	141	4	655	1	(1)	800
Total non-regulated revenue	2,339	72	6,836	76	(78)	9,245
Regulated Revenue						
Revenue from contracts with customers	—	3,391	—	—	—	3,391
Other regulated revenue	—	32	—	—	—	32
Total regulated revenue	—	3,423	—	—	—	3,423
Total revenue	$ 2,339	$ 3,495	$ 6,836	$ 76	$ (78)	$ 12,668

	Year Ended December 31, 2022					
	Renewables SBU	Utilities SBU	Energy Infrastructure SBU	New Energy Technologies SBU	Corporate, Other and Eliminations	Total
Non-Regulated Revenue						
Revenue from contracts with customers	$ 1,791	$ 75	$ 6,871	$ 1	$ (100)	$ 8,638
Other non-regulated revenue [1]	102	4	333	2	—	441
Total non-regulated revenue	1,893	79	7,204	3	(100)	9,079
Regulated Revenue						
Revenue from contracts with customers	—	3,507	—	—	—	3,507
Other regulated revenue	—	31	—	—	—	31
Total regulated revenue	—	3,538	—	—	—	3,538
Total revenue	$ 1,893	$ 3,617	$ 7,204	$ 3	$ (100)	$ 12,617

	Year Ended December 31, 2021					
	Renewables SBU	Utilities SBU	Energy Infrastructure SBU	New Energy Technologies SBU	Corporate, Other and Eliminations	Total
Non-Regulated Revenue						
Revenue from contracts with customers	$ 1,438	$ 73	$ 6,143	$ 6	$ (74)	$ 7,586
Other non-regulated revenue [1]	124	3	559	1	—	687
Total non-regulated revenue	1,562	76	6,702	7	(74)	8,273
Regulated Revenue						
Revenue from contracts with customers	—	2,831	—	—	—	2,831
Other regulated revenue	—	37	—	—	—	37
Total regulated revenue	—	2,868	—	—	—	2,868
Total revenue	$ 1,562	$ 2,944	$ 6,702	$ 7	$ (74)	$ 11,141

(1) Other non-regulated revenue primarily includes lease and derivative revenue not accounted for under ASC 606.

Contract Balances — The timing of revenue recognition, billings, and cash collections results in accounts receivable and contract liabilities. The contract liabilities from contracts with customers were $328 million and $337 million as of December 31, 2023 and December 31, 2022, respectively.

During the years ended December 31, 2023 and 2022, we recognized revenue of $70 million and $36 million, respectively, that was included in the corresponding contract liability balance at the beginning of the periods.

In June 2023, the Company closed on an agreement to terminate the PPA for the Warrior Run coal-fired power plant for total consideration of $357 million, to be paid by the offtaker through the end of the previous contract term in January 2030. Under the termination agreement, the plant will continue providing capacity through May 2024. The termination represents a contract modification under which the discounted termination payments, as well as a pre-existing contract liability, will be recognized as revenue on a straight-line basis over the remaining performance obligation period for approximately $32 million per month. As of December 31, 2023, the corresponding receivable balance was $148 million, of which $40 million and $108 million was recorded in *Other current assets* and *Other noncurrent assets*, respectively, on the Consolidated Balance Sheet. A significant financing component of $57 million is being recognized over the life of the payment term as interest income using the effective interest method.

In August 2020, AES Andes reached an agreement with Minera Escondida and Minera Spence to early terminate two PPAs of the Angamos coal-fired plant in Chile, further accelerating AES Andes' decarbonization strategy. As a result of the termination payment, Angamos recognized a contract liability of $655 million, of which $55 million was derecognized each month through the end of the remaining performance obligation in August 2021.

A significant financing arrangement exists for our Mong Duong plant in Vietnam. The plant was constructed under a BOT contract and will be transferred to the Vietnamese government after the completion of a 25 year PPA. The performance obligation to construct the facility was substantially completed in 2015. Contract consideration related to the construction, but not yet collected through the 25 year PPA, was reflected on the Consolidated Balance Sheet. As of December 31, 2022, the Mong Duong loan receivable balance was $1.1 billion, net of CECL reserve of $28 million. Of the loan receivable balance, $97 million was classified as *Other current assets*, and $1 billion as *Other noncurrent assets* on the Consolidated Balance Sheet as of December 31, 2022. As of December 31, 2023, Mong Duong met the held-for-sale criteria and the loan receivable balance of $1.1 billion, net of CECL reserve of $26 million was classified as held-for-sale assets. Of the loan receivable balance, $108 million was classified as *Current held-for-sale assets*, and $962 million was classified as *Noncurrent held-for-sale assets*, respectively. See Note 24—*Held-for-Sale and Dispositions* for further information.

Remaining Performance Obligations — The transaction price allocated to remaining performance obligations represents future consideration for unsatisfied (or partially unsatisfied) performance obligations at the end of the reporting period. As of December 31, 2023, the aggregate amount of transaction price allocated to remaining performance obligations was $7 million, primarily consisting of fixed consideration for the sale of renewable energy credits ("RECs") in long-term contracts in the U.S. We expect to recognize revenue of approximately $1 million per year between 2024 and 2028, and the remainder thereafter.

21. OTHER INCOME AND EXPENSE

Other income generally includes gains on insurance recoveries in excess of property damage, gains on asset sales and liability extinguishments, favorable judgments on contingencies, allowance for funds used during construction, and other income from miscellaneous transactions. Other expense generally includes losses on asset sales and dispositions, losses on legal contingencies, and losses from other miscellaneous transactions. The components are summarized as follows (in millions):

	Year Ended December 31,	2023	2022	2021
Other Income	Gain on sale and disposal of assets	$ 19	$ —	$ 24
	Gain on remeasurement of contingent consideration [(1)]	16	3	28
	AFUDC (US Utilities)	14	10	8
	Insurance proceeds [(2)]	6	12	—
	Dividend income on investments	6	3	1
	Legal settlements [(3)]	4	6	53
	Gain on remeasurement of investment [(4)]	—	22	—
	Liquidated damages under a power sales agreement	—	10	—
	Gain on remeasurement to acquisition-date fair value [(5)]	—	5	254
	Non-service pension income	—	5	10
	Gain on acquired customer contracts	—	5	—
	Gain on pension curtailment	—	—	11
	Other	24	21	21
	Total other income	$ 89	$ 102	$ 410
Other Expense	Loss on sale and disposal of assets [(6)]	$ 49	$ 13	$ 14
	Loss on commencement of sales-type leases [(7)]	20	5	13
	Non-service pension and other postretirement costs	12	—	—
	Legal contingencies and settlements	2	8	2
	Cost of disposition of business interests [(8)]	—	15	—
	Loss on sale of receivables [(9)]	—	—	9
	Other	16	27	22
	Total other expense	$ 99	$ 68	$ 60

(1) Related to certain remeasurements of contingent consideration on projects acquired at AES Clean Energy. See Note 25—*Acquisitions* for further information.

(2) For the year ended December 31, 2022, primarily related to insurance recoveries associated with property damage at TermoAndes.

(3) For the year ended December 31, 2021, primarily related to settlement of legal arbitration at Alto Maipo.

(4) For the year ended December 31, 2022, related to the remeasurement of our existing investment in 5B, accounted for using the measurement alternative.

(5) For the year ended December 31, 2021, related to the remeasurement of our existing equity interest in sPower's development platform as part of the step acquisition to form AES Clean Energy Development. See Note 25—*Acquisitions* for further information.

(6) For the year ended December 31, 2023, primarily related to impairments of inventory due to planned early plant closures at Ventanas 2, Norgener, and Warrior Run.

(7) Related to losses recognized at commencement of sales-type leases at AES Renewable Holdings. See Note 14—*Leases* for further information.

(8) Cost of disposition of a business interest at AES Gilbert due to a fire incident in April 2022, including the recognition of an allowance on the sales-type lease receivable.

(9) Associated with loss on sale of Stabilization Fund receivables at AES Andes. See Note 7—*Financing Receivables* for further information.

22. ASSET IMPAIRMENT EXPENSE

Year ended December 31, (in millions)	2023	2022	2021
Warrior Run	$ 198	$ —	$ —
New York Wind	186	—	—
Mong Duong	167	—	—
AES Clean Energy Development Projects	151	18	18
Norgener	137	—	—
TEG	77	104	—
TEP	59	89	—
Jordan	59	76	—
GAF Projects (AES Renewable Holdings)	18	—	—
Buffalo Gap III	6	—	91
Buffalo Gap I	4	—	29
Maritza	—	468	—
Ventanas 3 & 4	—	—	649
Puerto Rico	—	—	475
Angamos	—	—	155
Buffalo Gap II	—	—	73
Mountain View I & II	—	—	67
Estrella del Mar I	—	—	11
Other	5	8	7
Total	$ 1,067	$ 763	$ 1,575

Warrior Run — On September 30, 2023, the Company filed a Generator Deactivation Notice with PJM stating its intention to either retire or mothball the Warrior Run coal-fired facility on June 1, 2024. On November 30, 2023, PJM approved the potential deactivation, therefore management reassessed the economic useful life of the generation facility. Due to the approval from PJM and the absence of other economically viable options, an impairment indicator was identified. The Company performed an impairment analysis as of November 30, 2023, and determined that the fair value of the asset group was $25 million, using the income approach. As a result, and since pre-tax losses are limited to the carrying value of the long-lived assets, the Company recognized pre-tax asset impairment expense of $198 million. Warrior Run is reported in the Energy Infrastructure SBU reportable segment.

New York Wind — In November 2023, AES Clean Energy Development, LLC ("ACED") was awarded ten projects from NYSERDA, six of which were related to the repowering of existing wind assets in New York that were acquired in November 2021. On November 28, 2023, the Company approved plans to execute the repowering project and sign a PPA with NYSERDA for the energy and capacity related to the repowered assets. As the repowering will result in decommissioning the existing turbines and reducing their depreciable lives, the approval to move forward with the repowering project was identified as an impairment indicator. The Company performed an impairment analysis as of November 30, 2023, and determined that the fair value of the asset group was $124 million, using the income approach. As a result, the Company recognized pre-tax asset impairment expense of $186 million. New York Wind is reported in the Renewables SBU reportable segment.

Mong Duong — In November 2023, the Company entered into an agreement to sell its entire 51% ownership interest in Mong Duong 2, a coal-fired plant in Vietnam, and 51% equity interest in Mong Duong Finance Holdings B.V., an SPV accounted for as an equity affiliate (collectively "Mong Duong"). As of December 31, 2023, Mong Duong was classified as held-for-sale. The carrying amount of Mong Duong exceeded the agreed-upon sales price and as a result, the Company recognized pre-tax impairment expense of $167 million. See Note 24—*Held-for-Sale and Dispositions* for further information. Mong Duong is reported in the Energy Infrastructure SBU reportable segment.

AES Clean Energy Development Projects — AES Clean Energy Development has a pipeline of U.S. renewable projects that are in various stages of development and construction. In some cases, if development efforts are not successful, the Company may abandon a particular project, writing off all the intangible assets and capitalized development costs incurred. The fair value of each abandoned project with no salvage value is presumed to be zero as there are no future projected cash flows.

In 2023, 2022, and 2021, the Company recognized pre-tax asset impairment expense related to the write-off of projects that were determined to be no longer viable totaling $151 million, $18 million, and $18 million, respectively. The impairment expense recognized in 2023 primarily relates to the write-off of project development intangibles which were recognized at fair value when the Company acquired sPower's development platform as part of the formation of AES Clean Energy Development. See Note 25—*Acquisitions* for further information. The write-off of capitalized development costs incurred remained consistent with prior years. AES Clean Energy Development is reported in the Renewables SBU reportable segment.

TEG and TEP — On October 1, 2022, the Company performed the annual goodwill impairment test for the TEG TEP reporting unit. The quantitative impairment test resulted in an estimated fair value of the reporting unit which was less than its carrying amount. The failure of the goodwill impairment test was identified as an impairment indicator for the long-lived assets of the TEG and TEP asset groups. The Company performed an impairment analysis as of October 1, 2022, and determined that the carrying amounts of the asset groups were not recoverable. The TEG and TEP asset groups were determined to have fair values of $164 million and $147 million, respectively, using the income approach. As a result, the Company recognized pre-tax asset impairment expense of $104 million and $89 million, respectively. Subsequent to the asset impairment being recorded, the Company re-performed the goodwill test and no impairment was noted.

During the third quarter of 2023, management identified an impairment indicator at the TEG and TEP asset groups due to a reduction in expected capacity cash flows after expiration of the current PPA. The Company performed an impairment analysis as of July 31, 2023, and determined that the carrying amounts of the asset groups were not recoverable. The TEG and TEP asset groups were determined to have fair values of $93 million and $94 million, respectively, using the income approach. As a result, the Company recognized pre-tax asset impairment expense of $77 million and $59 million, respectively. TEG and TEP are reported in the Energy Infrastructure SBU reportable segment.

Norgener — In May 2023, AES Andes announced its intention to accelerate the retirement of the Norgener coal-fired plant in Chile in order to further advance its decarbonization strategy. Due to this strategic development and the resulting decrease in useful life of the generation facility, the Company performed an impairment analysis as of May 1, 2023, and determined that the carrying amount of the asset group was not recoverable. The Norgener asset group was determined to have a fair value of $24 million, using the income approach. As a result, and since pre-tax losses are limited to the carrying amount of the long-lived assets, the Company recognized pre-tax asset impairment expense of $137 million. Norgener is reported in the Energy Infrastructure SBU reportable segment.

Jordan — In November 2020, the Company signed an agreement to sell 26% ownership interest in Amman East and IPP4 for $58 million and as of December 31, 2023, the generation plants continued to be classified as held-for-sale. Due to the delay in closing the transaction, the carrying amount of the asset group in subsequent periods exceeded the agreed-upon sales price and total pre-tax impairment expense of $59 million and $76 million was recorded during 2023 and 2022, respectively. See Note 24—*Held-for-Sale and Dispositions* for further information. Amman East and IPP4 are reported in the Energy Infrastructure SBU reportable segment.

GAF Projects — During the second quarter of 2023, management concluded that the carrying value of six project companies at AES Renewable Holdings (the “GAF Projects”) may not be recoverable as the expected purchase price on the buyout of tax equity investors implied a loss on the transaction. The buyout was completed in July 2023. Management performed a recoverability test as of May 31, 2023 and concluded that the undiscounted cash flows of the GAF Projects did not exceed the carrying values of the asset groups for five of the six projects. The asset groups for the GAF Projects were determined to have a fair value of $11 million, using the income approach. As a result, the Company recognized pre-tax asset impairment expense of $18 million. AES Renewable Holdings is reported in the Renewables SBU reportable segment.

Maritza — In May 2022, the Council for the European Union approved Bulgaria’s National Recovery and Resilience plan which commits the country to cease generating electricity from coal beyond 2038. As this plan is expected to prohibit the Company from operating the Maritza coal-fired plant through its estimated useful life, it was determined that an indicator of impairment had occurred. The Company reassessed the useful life of the facility and performed an impairment analysis as of April 30, 2022, in which it was determined that the carrying amount of the asset group was not recoverable. The Maritza asset group was determined to have a fair value of $452 million using the income approach. As a result, the Company recognized pre-tax asset impairment expense of $468 million. Maritza is reported in the Energy Infrastructure SBU reportable segment.

Buffalo Gap — During the fourth quarter of 2021, due to an expired PPA and volatile spot prices in the ERCOT market, management concluded that the carrying value of the long-lived assets of Buffalo Gap I, II, and III wind generation facilities may not be recoverable. As such, the Company performed an impairment analysis and determined that the fair value of each asset group, using the income approach, was zero. As a result, the Company recognized pre-tax asset impairment expense of $29 million, $73 million, and $91 million at Buffalo Gap I, II, and III, respectively. During the fourth quarter of 2023, the Company recorded and subsequently impaired asset retirement costs of $4 million and $6 million related to Buffalo Gap I and III, respectively. The Buffalo Gap wind generation facilities are reported in the Renewables SBU reportable segment.

Ventanas and Angamos — In July 2021, AES Andes entered into an agreement committing to accelerate the retirement of the Ventanas 3, Ventanas 4, Angamos 1, and Angamos 2 coal-fired plants in Chile. Due to these strategic developments, the Company performed impairment analyses as of June 30, 2021, and determined that the carrying amounts of the asset groups were not recoverable. The Ventanas 3 & 4 and Angamos asset groups were determined to have fair values of $12 million and $86 million, respectively, using the income approach. As a result, the Company recognized pre-tax asset impairment expense of $649 million and $155 million, respectively. Ventanas and Angamos are reported in the Energy Infrastructure SBU reportable segment.

Mountain View I & II — In April 2021, the Company approved plans to execute a repowering project for the Mountain View I & II wind facility and signed two new PPAs for the energy and capacity related to the repowered asset. As the repowering will result in decommissioning the majority of the existing wind turbines in advance of their depreciable lives, the execution of the new PPAs was identified as an impairment indicator. The asset group was determined to have a fair value of $11 million using the income approach. As a result, the Company recognized pre-tax asset impairment expense of $67 million. Mountain View I & II is reported in the Renewables SBU reportable segment.

Puerto Rico — New factors arose in the first quarter of 2021 associated with the economic costs and operational and reputational risks of disposal of coal combustion residuals off island. In addition, new legislative initiatives surrounding the prohibition of coal generation assets in Puerto Rico were introduced. Collectively, these factors along with management's decision on how to best achieve our stated decarbonization goals resulted in an indicator of impairment at our asset group in Puerto Rico. As such, management performed a recoverability test in accordance with ASC 360 and concluded that Puerto Rico's undiscounted cash flows did not exceed the carrying value of the asset group. The fair value of the asset group was determined to be $73 million, resulting in pre-tax impairment expense of $475 million. Puerto Rico is reported in the Energy Infrastructure SBU reportable segment.

Estrella del Mar I — In September 2021, the Company recognized asset impairment expense of $11 million due to a change in the estimated market value of the Estrella del Mar I power barge. The Company completed the sale of the power barge in November 2021. See Note 24—*Held-for-Sale and Dispositions* for further information. Prior to its sale, Estrella del Mar I was reported in the Renewables SBU reportable segment.

23. INCOME TAXES

Income Tax Provision — The following table summarizes the expense for income taxes on continuing operations for the periods indicated (in millions):

December 31,		2023	2022	2021
Federal:	Current	$ 9	$ 3	$ (2)
	Deferred	15	(18)	42
State:	Current	16	2	1
	Deferred	30	1	18
Foreign:	Current	289	256	273
	Deferred	(98)	21	(465)
Total		$ 261	$ 265	$ (133)

Effective and Statutory Rate Reconciliation — The following table summarizes a reconciliation of the U.S. statutory federal income tax rate to the Company's effective tax rate as a percentage of income from continuing operations before taxes for the periods indicated:

December 31,	2023	2022	2021
Statutory Federal tax rate	21 %	21 %	21 %
State taxes, net of Federal tax benefit	87 %	(1)%	(6)%
Taxes on foreign earnings	14 %	(42)%	(2)%
Valuation allowance	83 %	(10)%	7 %
Uncertain tax positions	— %	7 %	16 %
Change in tax law	— %	— %	(1)%
U.S. Investment Tax Credit	(70)%	— %	— %
Noncontrolling interest in U.S. subsidiaries	115 %	— %	— %
Alto Maipo deconsolidation	— %	— %	(17)%
Noncontrolling interest on Buffalo Gap impairments	— %	— %	(3)%
Nondeductible goodwill impairments	3 %	(127)%	— %
Other—net	(2)%	(5)%	(2)%
Effective tax rate	251 %	(157)%	13 %

For 2023, included in the 14% taxes on foreign earnings are inflationary and foreign currency benefits at our Argentine businesses. Further, the Company recorded tax expense associated with the change in realizability of deferred tax assets at certain of those Argentine businesses, which is included in the 83% valuation allowance item. The (70)% U.S. Investment Tax Credit relates to investment tax credits for renewables projects placed in service this year. Not included in the 2023 effective tax rate is $28 million of income tax expense recorded to additional paid-in capital resulting from the Company's sales of a 20% ownership interest in AES Dominicana and a 35% ownership interest in Colon. See Note 17—*Equity* for details of the sales.

For 2022, included in the (42)% taxes on foreign earnings is the impact of favorable LNG transactions at the Energy Infrastructure SBU and inflation and foreign currency impacts at certain Argentine businesses. The (127)% nondeductible goodwill impairments relates to the impairments at AES Andes and AES El Salvador. Not included in the 2022 effective tax rate is $27 million of income tax expense recorded to additional paid-in capital related to the

Company's sale of a 14.9% ownership interest in the Southland Energy assets. See Note 17—*Equity* for details of the sale.

For 2021, included in the 7% for valuation allowance is approximately $93 million related to the release of valuation allowance at one of our Brazilian subsidiaries. Included in the 16% uncertain tax positions is approximately $176 million of income tax benefit related to effective settlement resulting from the exam closure of the Company’s U.S. 2017 tax return, the focus of which was on the TCJA one-time transition tax. The (17)% included in the Alto Maipo deconsolidation item above primarily reflects the lack of tax benefit for approximately $775 million of the $2,074 million pretax Alto Maipo deconsolidation loss. Also included in this item is approximately $41 million of tax benefit related to resulting tax over book outside basis difference in Alto Maipo, which is offset by $41 million of tax expense in the valuation allowance line item. The (3)% Buffalo Gap impairments item relates to the amounts of impairment allocated to tax equity noncontrolling interest which are nondeductible.

Income Tax Receivables and Payables — The current income taxes receivable and payable are included in *Other current assets* and *Accrued and other liabilities*, respectively, on the accompanying Consolidated Balance Sheets. The noncurrent income taxes receivable and payable are included in *Other noncurrent assets* and *Other noncurrent liabilities*, respectively, on the accompanying Consolidated Balance Sheets. The following table summarizes the income taxes receivable and payable as of the periods indicated (in millions):

December 31,	**2023**	**2022**
Income taxes receivable—current	$ 95	$ 107
Income taxes receivable—noncurrent	41	69
Total income taxes receivable	$ 136	$ 176
Income taxes payable—current	$ 103	$ 104
Income taxes payable—noncurrent	—	—
Total income taxes payable	$ 103	$ 104

Deferred Income Taxes — Deferred income taxes reflect the net tax effects of (a) temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and (b) operating loss and tax credit carryforwards. These items are stated at the enacted tax rates that are expected to be in effect when taxes are actually paid or recovered.

As of December 31, 2023, the Company had federal net operating loss carryforwards for tax return purposes of approximately $769 million, which carry forward indefinitely. The Company also had federal general business tax credit carryforwards of approximately $79 million, which expire in 2040 and beyond. Additionally, the Company had state net operating loss carryforwards as of December 31, 2023 of approximately $4.8 billion expiring primarily in years 2024 to 2042. As of December 31, 2023, the Company had foreign net operating loss carryforwards of approximately $2.9 billion that expire at various times beginning in 2024 and some of which carry forward without expiration.

Valuation allowances increased $95 million during 2023 to $672 million at December 31, 2023. This net increase was primarily due to valuation allowance established at acquisition of a Chilean subsidiary, as well as changes in realizability of deferred tax assets at certain Argentine subsidiaries.

Valuation allowances increased $49 million during 2022 to $577 million at December 31, 2022. This net increase was primarily the result of valuation allowance established at acquisition of a Brazilian subsidiary.

The Company believes that it is more likely than not that the net deferred tax assets as shown below will be realized when future taxable income is generated through the reversal of existing taxable temporary differences and income that is expected to be generated by businesses that have long-term contracts or a history of generating taxable income.

The following table summarizes deferred tax assets and liabilities, as of the periods indicated (in millions):

December 31,	2023	2022
Differences between book and tax basis of property	$ (966)	$ (903)
Investment in U.S. tax partnerships	(578)	(582)
Other taxable temporary differences	(403)	(350)
Total deferred tax liability	(1,947)	(1,835)
Operating loss carryforwards	1,132	1,129
Capital loss carryforwards	65	62
Bad debt and other book provisions	92	57
Tax credit carryforwards	72	62
Other deductible temporary differences	409	282
Total gross deferred tax asset	1,770	1,592
Less: Valuation allowance	(672)	(577)
Total net deferred tax asset	1,098	1,015
Net deferred tax liability	$ (849)	$ (820)

The Company considers undistributed earnings of certain foreign subsidiaries to be indefinitely reinvested outside of the U.S. Except for the one-time transition tax in the U.S., no taxes have been recorded with respect to our indefinitely reinvested earnings in accordance with the relevant accounting guidance for income taxes. Should the earnings be remitted as dividends, the Company may be subject to additional foreign withholding and state income taxes. Under the TCJA, future distributions from foreign subsidiaries will generally be subject to a federal dividends received deduction in the U.S. As of December 31, 2023, the cumulative amount of U.S. GAAP foreign un-remitted earnings upon which additional income taxes have not been provided is approximately $4 billion. It is not practicable to estimate the amount of any additional taxes which may be payable on the undistributed earnings.

Income from operations in certain countries is subject to reduced tax rates as a result of satisfying specific commitments regarding employment and capital investment. The Company's income tax benefits related to the tax status of these operations are estimated to be $19 million, $27 million and $27 million for the years ended December 31, 2023, 2022 and 2021, respectively. The per share effect of these benefits after noncontrolling interests was $0.02 for each of the years ended December 31, 2023, 2022 and 2021. Included in the Company's income tax benefits is the benefit related to our operations in Vietnam, which is estimated to be $16 million, $18 million and $16 million for the years ended December 31, 2023, 2022 and 2021, respectively. The per share effect of these benefits related to our operations in Vietnam after noncontrolling interest was $0.01 for each of the years ended December 31, 2023, 2022 and 2021.

The following table shows the income (loss) from continuing operations, before income taxes, net equity in earnings of affiliates and noncontrolling interests, for the periods indicated (in millions):

December 31,	2023	2022	2021
U.S.	$ (238)	$ 22	$ 622
Non-U.S.	342	(191)	(1,686)
Total	$ 104	$ (169)	$ (1,064)

Uncertain Tax Positions — Uncertain tax positions have been classified as noncurrent income tax liabilities unless they are expected to be paid within one year. The Company's policy for interest and penalties related to income tax exposures is to recognize interest and penalties as a component of the provision for income taxes in the Consolidated Statements of Operations. The following table shows the total amount of gross accrued income taxes related to interest and penalties included in the Consolidated Balance Sheets for the periods indicated (in millions):

December 31,	2023	2022
Interest related	$ 2	$ 2
Penalties related	—	—

The following table shows the expense/(benefit) related to interest and penalties on unrecognized tax benefits for the periods indicated (in millions):

December 31,	2023	2022	2021
Total benefit for interest related to unrecognized tax benefits	$ —	$ —	$ 1
Total expense for penalties related to unrecognized tax benefits	—	—	1

We are potentially subject to income tax audits in numerous jurisdictions in the U.S. and internationally until the applicable statute of limitations expires. Tax audits by their nature are often complex and can require several years to complete. The following is a summary of tax years potentially subject to examination in the significant tax and business jurisdictions in which we operate:

Jurisdiction	Tax Years Subject to Examination
Argentina	2017-2023
Brazil	2017-2023
Chile	2020-2023
Colombia	2017-2023
Dominican Republic	2020-2023
El Salvador	2020-2023
Netherlands	2017-2023
Panama	2020-2023
United Kingdom	2020-2023
United States (Federal)	2017-2023

As of December 31, 2023, 2022 and 2021, the total amount of unrecognized tax benefits was $107 million, $107 million and $122 million, respectively. The total amount of unrecognized tax benefits that would benefit the effective tax rate as of December 31, 2023, 2022 and 2021 is $107 million, $107 million and $122 million, respectively, of which $1 million, $2 million, and $4 million, respectively, would be in the form of tax attributes that would warrant a full valuation allowance. Further, the total amount of unrecognized tax benefit that would benefit the effective tax rate as of 2023 would be reduced by approximately $34 million of tax expense related to remeasurement from 35% to 21%.

The total amount of unrecognized tax benefits anticipated to result in a net increase to unrecognized tax benefits within 12 months of December 31, 2023 is estimated to be between zero and $10 million, primarily as a result of ongoing audits, including potential tax exam resolutions.

The following is a reconciliation of the beginning and ending amounts of unrecognized tax benefits for the periods indicated (in millions):

	2023	2022	2021
Balance at January 1	$ 107	$ 122	$ 458
Additions for current year tax positions	1	4	28
Additions for tax positions of prior years	—	—	14
Reductions for tax positions of prior years	(1)	(16)	—
Settlements	—	(3)	(377)
Lapse of statute of limitations	—	—	(1)
Balance at December 31	$ 107	$ 107	$ 122

The 2021 settlement amount of $377 million above primarily relates to effective settlement of historic unrecognized tax benefits as a result of the exam closure of the Company’s U.S. 2017 tax return, the focus of which was on the TCJA one-time transition tax assessed on cumulative foreign earnings and profits. This amount is based on the pre-TCJA income tax rate of 35% though the actual impact to the Company’s income tax expense is an income tax benefit computed at 21%.

The Company and certain of its subsidiaries are currently under examination by the relevant taxing authorities for various tax years. The Company regularly assesses the potential outcome of these examinations in each of the taxing jurisdictions when determining the adequacy of the amount of unrecognized tax benefit recorded. While it is often difficult to predict the final outcome or the timing of resolution of any particular uncertain tax position, we believe we have appropriately accrued for our uncertain tax benefits. However, audit outcomes and the timing of audit settlements and future events that would impact our previously recorded unrecognized tax benefits and the range of anticipated increases or decreases in unrecognized tax benefits are subject to significant uncertainty. It is possible that the ultimate outcome of current or future examinations may exceed our provision for current unrecognized tax benefits in amounts that could be material, but cannot be estimated as of December 31, 2023. Our effective tax rate and net income in any given future period could therefore be materially impacted.

24. HELD-FOR-SALE AND DISPOSITIONS

Held-for-Sale

Jordan — In November 2020, the Company signed an agreement to sell 26% ownership interest in Amman East and IPP4 for $58 million. The sale is expected to close in the first quarter of 2024. After completion of the sale, the Company will retain a 10% ownership interest in Amman East and IPP4, which will be accounted for as an equity method investment. As of December 31, 2023, the generation plants continued to be classified as held-for-sale, but did not meet the criteria to be reported as discontinued operations. On a consolidated basis, the carrying value of net assets after impairment of the plants held-for-sale as of December 31, 2023 was $164 million. Amman East and IPP4 are reported in the Energy Infrastructure SBU reportable segment.

Mong Duong — In November 2023, the Company entered into an agreement to sell its entire 51% ownership interest in Mong Duong 2, a coal-fired plant in Vietnam, and 51% equity interest in Mong Duong Finance Holdings B.V, an SPV accounted for as an equity affiliate (collectively "Mong Duong"). The sale is subject to regulatory approval and is expected to close in mid-2025. As a result, Mong Duong was classified as held-for-sale, but did not meet the criteria to be reported as discontinued operations. On a consolidated basis, the carrying value of net assets after impairment of the plant held-for-sale as of December 31, 2023 was $396 million. Mong Duong is reported in the Energy Infrastructure SBU reportable segment.

Excluding any impairment charges, pre-tax income (loss) attributable to AES of businesses held-for-sale as of December 31, 2023 was as follows (in millions):

Year Ended December 31,	**2023**	**2022**	**2021**
Mong Duong	$ 40	$ 50	$ 56
Jordan	21	(6)	21
Total	$ 61	$ 44	$ 77

Management has recorded pre-tax asset impairment expense of $167 million at Mong Duong. See Note 22—*Asset Impairment Expense* for further information. As of December 31, 2023, the significant assets and liabilities of Mong Duong are a long term financing receivable of $1.1 billion and debt of $639 million, respectively. As of December 31, 2023, the significant assets and liabilities of Jordan are property, plant and equipment and debt of $300 million and $176 million, respectively.

Dispositions

Colon transmission line — In December 2021, Gas Natural Atlántico II S. de. R.L., completed the sale of its transmission line to Empresa de Transmision Electrica, S.A., a government entity in charge of transmission of energy in Panama, for $51 million, resulting in a pre-tax gain on sale of $6 million, reported in *Other income* on the Consolidated Statement of Operations. The sale did not meet the criteria to be reported as discontinued operations. Prior to its sale, the Colon transmission line was reported in the Energy Infrastructure SBU reportable segment.

Alto Maipo — In November 2021, Alto Maipo SpA filed a voluntary petition for relief under Chapter 11 of the U.S. Bankruptcy Code. Therefore, the Company determined it no longer had control over Alto Maipo, resulting in its deconsolidation. The Company recorded a pre-tax loss on deconsolidation of $2.1 billion in *Loss on disposal and sale of business interests* on the Consolidated Statement of Operations. As Alto Maipo represents a component of AES Andes' single reporting unit, the carrying value of the net assets of Alto Maipo included an allocation of $224 million of AES Andes' consolidated goodwill balance of $868 million prior to deconsolidation. The Company allocated AES Andes' goodwill based on the relative fair value of the component, which was determined based on the relative fair values of the business to be disposed and the portion of the reporting unit to be retained. Subsequent to the deconsolidation of Alto Maipo, the company evaluated the remaining Andes Reporting Unit goodwill and determined the goodwill was not at-risk.

The deconsolidation did not meet the criteria to be reported as discontinued operations. After deconsolidation, the Company's retained investment in Alto Maipo was recognized as a financial asset with zero fair value, utilizing a restructuring model of cash flows and a cost of equity of 21%. Prior to deconsolidation, Alto Maipo was reported in the Energy Infrastructure SBU reportable segment. See Note 5—*Fair Value,* Note 8—*Investments In and Advances to Affiliates,* Note 9—*Goodwill and Other Intangible Assets,* and Note 17—*Equity* for further information.

Estrella del Mar I — In November 2021, the Company completed the sale of the Estrella del Mar I power barge for $6 million. The sale did not meet the criteria to be reported as discontinued operations. Prior to its sale, Estrella del Mar I was reported in the Renewables SBU reportable segment. See Note 22—*Asset Impairment Expense* for further information.

AES Tietê Inova Soluções — In June 2021, the Company completed the sale of its ownership in AES Inova Soluções, an investment platform in distributed solar generation, for $20 million, resulting in a pre-tax loss on sale of $1 million. The sale did not meet the criteria to be reported as discontinued operations. Prior to its sale, AES Tietê Inova Soluções was reported in the Renewables SBU reportable segment.

Itabo — In April 2021, the Company completed the sale of its 43% ownership interest in Itabo, a coal-fired plant and gas turbine in Dominican Republic, for $88 million, resulting in a pre-tax gain on sale of $4 million. The sale did not meet the criteria to be reported as discontinued operations. Prior to its sale, Itabo was reported in the Energy Infrastructure SBU reportable segment.

The following table summarizes, excluding any impairment charge or gain/loss on sale, the pre-tax income attributable to AES of disposed businesses for the periods indicated (in millions):

Year Ended December 31,	2023	2022	2021
Alto Maipo	$ —	$ —	$ 35
Itabo	—	—	5
Total	$ —	$ —	$ 40

25. ACQUISITIONS

Rexford — On October 2, 2023, the Company, through its subsidiary Rexford 1 Holdings, LLC., entered into an agreement for the purchase of 100% of the membership interests in 20SD 8me LLC., a 300 MW solar and 240 MW BESS project. The transaction was accounted for as an asset acquisition of variable interest entities that did not meet the definition of a business. The assets acquired and liabilities assumed were recorded at their fair values, which equaled the fair value of the consideration paid of approximately $253 million, including contingent consideration of $4 million. The nature of the assets acquired is largely tangible as they relate to construction in progress, along with typical working capital items and certain equipment.

We estimated the fair value of the construction in progress at approximately $282 million, using a discounted cash flow valuation methodology. The cash flow assumptions align with executed contracts, and incorporate forward energy pricing curves after the expiration date of such contracts. The cash flow and discount rates assumptions are considered Level 3 inputs. The contingent consideration will be updated quarterly with any prospective changes in fair value recorded through earnings. Rexford is reported in the Renewables SBU reportable segment.

Petersburg Solar Project — On August 31, 2023, the Company entered into agreements for project development and for the purchase of 100% of the membership in Petersburg Energy Center, LLC, a 250 MW solar and BESS project. The transaction was accounted for as an asset acquisition of variable interest entities that did not meet the definition of a business. The assets acquired and liabilities assumed were recorded at their fair values, which equaled the fair value of the consideration paid of approximately $49 million. Petersburg Solar Project is reported in the Utilities SBU reportable segment.

Calhoun — On July 18, 2023, the Company entered into an agreement for the purchase of 100% of the membership interests in Calhoun County Solar Project, LLC., which holds a late development-stage 125 MW solar project. The transaction was accounted for as an asset acquisition of variable interest entities that did not meet the definition of a business. The assets acquired and liabilities assumed were recorded at their fair values, which equaled the fair value of the consideration paid of approximately $64 million, including contingent consideration of $42 million. The estimated fair value of the contingent consideration for Calhoun was determined using probability-weighted discounted cash flows based on internal forecasts, which are considered Level 3 inputs. The probability of achieving the milestone payment used to calculate the acquisition date fair value of the contingent consideration was 99%. Payments under the contingent consideration arrangement are largely binary and thus, a single probability of achieving the milestone was applied in the calculation of fair value. The contingent consideration will be updated quarterly with any prospective changes in fair value recorded through earnings. Calhoun is reported in the Renewables SBU reportable segment.

Bellefield — On June 5, 2023, the Company entered into an agreement for the purchase of 100% of the membership interests in the Bellefield projects, consisting of two late development-stage solar and BESS projects of 1 GW each. The transaction was accounted for as an asset acquisition of variable interest entities that did not meet the definition of a business. The Company agreed to make total cash payments including reimbursement of development and equipment costs of up to approximately $449 million, a portion of which is contingent upon future milestones and price adjustments. This contingent consideration will be updated quarterly with any prospective changes in fair value recorded through earnings.

The assets acquired and liabilities assumed were recorded at their fair values, which equaled the fair value of the consideration to be paid of approximately $358 million, including cash paid of $165 million, contingent consideration of $165 million, and deferred payments of $28 million. The significant assets acquired include project development intangibles, land option intangibles, deposits made towards integral equipment purchases, and typical working capital items.

We estimated the fair value of the project development intangibles at approximately $200 million, using a discounted cash flow valuation methodology. The cash flow assumptions align with executed contracts, and incorporate forward energy pricing curves after the expiration date of such contracts. The cash flow assumptions and discount rates are considered Level 3 inputs.

We estimated the fair value of the land option intangibles at approximately $82 million, by comparing the intrinsic value (estimated using a sales comparison approach for purchase options and an income capitalization method for lease options) and the strike price of each option.

The estimated fair value of the contingent consideration of Bellefield was determined using probability-weighted discounted cash flows based on internal forecasts, which are considered Level 3 inputs. The weighted average probability of achieving the development milestones used to calculate the acquisition date fair value of the contingent consideration was 91.9%. Payments under the contingent consideration arrangements are largely binary and thus, a single probability of achieving the milestone was applied in the calculation of fair value. The contingent consideration will be updated quarterly with any prospective changes in fair value recorded through earnings. Bellefield is reported in the Renewables SBU reportable segment.

Bolero Solar Park — On June 9, 2023, the Company, through its subsidiary AES Andes S.A., acquired 100% of the equity interests in Helio Atacama Tres SpA, owner of the Bolero photovoltaic power plant for consideration of $114 million. The transaction was accounted for as an asset acquisition that did not meet the definition of a business. As Helio Atacama Tres is not a VIE, any difference between the fair value of the assets and consideration transferred will be allocated to PP&E on a relative fair value basis. Helio Atacama Tres is reported in the Energy Infrastructure SBU reportable segment.

Cubico II — On November 30, 2022, the Company, through its subsidiary AES Brasil Energia S.A ("AES Brasil") acquired 100% of shares of an operational wind complex comprised of (i) Ventos de São Tomé Holding S.A., (ii) Ventos de São Tito Holdings S.A., and (iii) REB Empreendimentos e Administradora de Bens S.A. The transaction was accounted for as an asset acquisition that did not meet the definition of a business. The assets acquired and liabilities assumed were recorded at their relative fair values. The total purchase price for the acquisition was $185 million. The Cubico II wind complex is recorded in the Renewables SBU reportable segment.

Agua Clara — On June 17, 2022, the Company, through its subsidiaries AES Dominicana Renewable Energy and AES Andres DR, S.A., acquired 100% of the equity interests in Agua Clara, S.A.S., a wind project, for consideration of $98 million. The transaction was accounted for as an asset acquisition that did not meet the definition of a business. As Agua Clara is not a VIE, any difference between the fair value of the assets and consideration transferred was allocated to PP&E on a relative fair value basis. Agua Clara is reported in the Renewables SBU reportable segment.

Tunica Windpower, LLC — On June 17, 2022, the Company entered into an agreement for the purchase of 100% of the membership interests in Tunica Windpower, LLC. The transaction was accounted for as an asset acquisition of variable interest entities that did not meet the definition of a business. The assets acquired and liabilities assumed were recorded at their fair values, which equaled the fair value of the consideration paid of approximately $22 million, including contingent consideration of $7 million. The contingent consideration will be updated quarterly with any prospective changes in fair value recorded through earnings. Tunica Windpower is reported in the Renewables SBU reportable segment.

Windsor PV1, LLC — On May 27, 2022, the Company entered into an agreement for the purchase of 100% of the membership interests in Windsor PV1, LLC, an early development-stage solar project. The transaction was accounted for as an asset acquisition of variable interest entities that did not meet the definition of a business. The assets acquired and liabilities assumed were recorded at their fair values, which equaled the fair value of the consideration paid of approximately $17 million, including contingent consideration of $5 million. The contingent consideration will be updated quarterly with any prospective changes in fair value recorded through earnings. Windsor is reported in the Renewables SBU reportable segment.

New York Wind — In November 2021, AES Clean Energy Development, LLC completed the acquisition of Cogentrix Valcour Intermediate Holdings, LLC for $352 million cash consideration, including customary purchase price adjustments, plus the assumption of $126 million of non-recourse debt. The transaction includes operating wind assets spread across six sites and will complement AES Clean Energy's existing operating and development solar and energy storage assets in the state of New York. The transaction was accounted for as a business combination, therefore, the assets acquired and liabilities assumed at acquisition date were recorded at their fair values, which resulted in the recognition of $199 million of goodwill. This goodwill represents the potential opportunity to repower the acquired assets and thus obtain additional cash flows upon repowering. The Company recorded preliminary amounts for the purchase price allocation in 2021.

In the first quarter of 2022, the Company finalized the purchase price allocation related to the acquisition of Cogentrix Valcour Intermediate Holdings, LLC. There were no significant adjustments made to the preliminary purchase price allocation recorded in the fourth quarter of 2021 when the acquisition was completed. New York Wind is reported in the Renewables SBU reportable segment.

Hardy Hills Solar — In December 2021, AES Indiana completed the acquisition of Hardy Hills solar project, which included assets of $52 million primarily consisting of project development intangibles. The transaction was accounted for as an asset acquisition of a variable interest entity that did not meet the definition of a business; therefore, the individual assets and liabilities were recorded at their fair values. A $6 million gain was recorded in *Other income* on the Consolidated Statement of Operations for the difference between the consideration transferred and the assets and liabilities recognized. The total consideration included $3 million of contingent consideration dependent on the amount of certain future costs incurred by the project. Hardy Hills Solar is reported in the Utilities SBU reportable segment.

Community Energy — In December 2021, AES Clean Energy Development, LLC completed the acquisition of Community Energy, LLC for $217 million cash consideration, including customary purchase price adjustments, plus the assumption of $38 million of non-recourse debt. At closing, the Company made a cash payment of $232 million, which included $15 million of the assumed non-recourse debt. The transaction was accounted for as a business combination; therefore, the assets acquired and liabilities assumed at the acquisition date were recorded at their fair values, which resulted in the recognition of $90 million of goodwill.

In the first quarter of 2022, the Company finalized the purchase price allocation related to the acquisition of Community Energy, LLC. There were no significant adjustments made to the preliminary purchase price allocation recorded in the fourth quarter of 2021 when the acquisition was completed. Community Energy is reported in the Renewables SBU reportable segment.

sPower Projects — In December 2021, AES Clean Energy Development Holdings, LLC entered into an agreement with AIMCo, our minority partner in AES Clean Energy Development, LLC and our partner in the sPower equity method investment. As part of this transaction, AES acquired an additional 25% ownership interest in specifically identified projects of sPower from AIMCo, in exchange for a 25% ownership interest in the Mountain View and Laurel Mountain wind operating projects, plus $28 million cash.

The transaction was accounted for as an asset acquisition. The sPower projects received were remeasured at their acquisition-date fair values, resulting in the recognition of a $35 million gain, recorded in *Other Income* on the Consolidated Statement of Operations. See Note 8—*Investments in and Advances to Affiliates* for further information. The Company recorded $3 million in additional paid-in-capital, representing the difference between the fair value of the consideration transferred and the recognition of the noncontrolling interest.

Subsequent to the closing of the transaction, AES holds a 75% ownership interest in the Mountain View and Laurel Mountain wind operating projects and a 75% ownership interest in specifically identified projects of sPower through its ownership of AES Clean Energy Development, LLC, and 50% ownership interest in the sPower equity method investment. AIMCo holds the remaining 25% minority interest in AES Clean Energy Development, LLC and 50% ownership interest in sPower. sPower is reported in the Renewables SBU reportable segment.

Serra Verde Wind Project — In July 2021, AES Brasil completed the acquisition of the Serra Verde Wind Project for $18 million, including contingent consideration and working capital adjustment, with the last annual installment ended on July 19, 2023. The transaction was accounted for as an asset acquisition of variable interest entities that did not meet the definition of a business; therefore, the consideration transferred, plus transaction costs were allocated to the individual assets acquired and liabilities assumed based on their relative fair values. Serra Verde is reported in the Renewables SBU reportable segment.

Cajuína Wind Project — In May 2021, AES Brasil completed the acquisition of the Cajuína Wind Project phase I for $22 million, and in July 2021, AES Brasil completed the acquisition of the Cajuína Wind Project phase II for $24 million plus $3 million of contingent consideration paid in October, 2022. The cash payments were negotiated in four annual installments and the last payments will occur on March 31, 2024 and on July 29, 2024, respectively. These transactions were accounted for as asset acquisitions of variable interest entities that did not meet the definition of a business; therefore, the consideration transferred, plus transaction costs were allocated to the individual assets acquired and liabilities assumed based on their relative fair values. Cajuína is reported in the Renewables SBU reportable segment.

Cubico I — In April 2021, AES Brasil completed the acquisition of the Cubico I wind complex, which includes the Mandacaru and Salinas facilities, for $109 million, subject to customary working capital adjustments. The transaction was accounted for as an asset acquisition, therefore the consideration transferred, plus transaction costs, were allocated to the individual assets acquired and liabilities assumed based on their relative fair values. Cubico I is reported in the Renewables SBU reportable segment.

AES Clean Energy Development — In February 2021, the Company substantially completed the merger of the sPower and AES Renewable Holdings development platforms to form AES Clean Energy Development, which will serve as the development vehicle for all future renewables projects in the U.S. As part of the transaction, AES acquired an additional 25% ownership interest in the sPower development platform from AIMCo, our existing partner in the sPower equity method investment, in exchange for a 25% ownership interest in specifically identified development entities of AES Renewable Holdings, certain future exit rights in the new partnership, and $7 million of cash.

The sPower development platform was carved-out of AES' existing equity method investment. AES' basis in the portion of assets transferred was $102 million, and the contribution to AES Clean Energy Development resulted in a corresponding decrease in the carrying value of the sPower investment.

During the first quarter of 2021, the sPower development assets transferred were remeasured at their acquisition-date preliminary fair values, resulting in the recognition of a $36 million gain, recorded in *Other income* on the Consolidated Statement of Operations. The Company recorded $81 million in *Goodwill* as of the acquisition date, representing the difference between the fair value of the consideration transferred, the noncontrolling interest in the sPower development platform, and the acquisition-date fair value of the Company's previously held equity interest and the fair value of the identifiable assets acquired and liabilities assumed.

During the second quarter of 2021, the Company recorded measurement period adjustments as result of additional facts and circumstances that existed as of the date of the acquisition but were not yet known as of the time of the valuation performed in the first quarter of 2021. As a result, the estimated acquisition-date carrying value and fair values of the sPower development assets transferred were increased, which resulted in the recognition of an additional $178 million gain, for an updated gain of $214 million. Furthermore, the estimated goodwill as of the acquisition date was reduced to $45 million, as a result of adjustments to the fair value of the consideration paid and updates to the fair values of separately identifiable intangible assets. The Company finalized the purchase price allocation in the third quarter of 2021, which did not result in any material measurement period adjustments.

Subsequent to the closing of the transaction, AES holds a 75% ownership interest in AES Clean Energy Development. AIMCo holds the remaining 25% minority interest along with certain partnership rights, though currently not in effect, that would enable AIMCo to exit in the future. AIMCo's minority interest is recorded as temporary equity in *Redeemable stock of subsidiaries* on the Consolidated Balance Sheets. See Note 16—*Redeemable Stock of Subsidiaries* for further information. AES Clean Energy Development is reported in the Renewables SBU reportable segment.

Great Cove Solar— In January 2021 and May 2021, AES Clean Energy Development, LLC completed the acquisitions of Great Cove I and II, respectively. The fair value of the initial consideration paid to acquire Great Cove I and Great Cove II was $13 million and $24 million, which included contingent consideration liabilities of $6 million and $22 million, respectively. These acquisitions were accounted for as asset acquisitions of variable interest entities that did not meet the definition of a business; therefore, the assets acquired and liabilities assumed were recorded at their fair values, which equaled the fair value of the consideration. During the third quarter of 2021, the contingent liabilities which related primarily to certain price adjustment features were remeasured, resulting in contingent consideration assets of $2 million and $12 million for Great Cove I and Great Cove II, respectively. This remeasurement resulted in a gain of $32 million recorded in *Other income* in the Consolidated Statement of Operations during the third quarter of 2021. In October 2021, the Company amended the agreement, resulting in the reclassification of the previously contingent consideration assets to *Prepaid expenses*. In December 2021, the Company acquired Community Energy, LLC (as further described above), and such remaining prepaid amounts were written off to *Other income* in the Consolidated Statement of Operations. Great Cove Solar is reported in the Renewables SBU reportable segment.

26. EARNINGS PER SHARE

Basic and diluted earnings per share are based on the weighted-average number of shares of common stock and potential common stock outstanding during the period. Potential common stock, for purposes of determining diluted earnings per share, includes the effects of dilutive RSUs, stock options, and equity units. The effect of such potential common stock is computed using the treasury stock method for RSUs and stock options, and is computed using the if-converted method for equity units.

The following table is a reconciliation of the numerator and denominator of the basic and diluted earnings per share computation for income from continuing operations for the years ended December 31, 2023, 2022 and 2021, where income represents the numerator and weighted-average shares represent the denominator.

Year Ended December 31,	**2023**			**2022**			**2021**		
(in millions, except per share data)	**Income**	**Shares**	**$ per Share**	**Loss**	**Shares**	**$ per Share**	**Loss**	**Shares**	**$ per Share**
BASIC EARNINGS (LOSS) PER SHARE									
Income (loss) from continuing operations attributable to The AES Corporation common stockholders	$ 242	669	$ 0.36	$ (546)	668	$ (0.82)	$ (413)	666	$ (0.62)
EFFECT OF DILUTIVE SECURITIES									
Stock options	—	1	—	—	—	—	—	—	—
Restricted stock units	—	2	—	—	—	—	—	—	—
Equity units	1	40	(0.02)	—	—	—	—	—	—
DILUTED EARNINGS (LOSS) PER SHARE	$ 243	712	$ 0.34	$ (546)	668	$ (0.82)	$ (413)	666	$ (0.62)

The calculation of diluted earnings per share excluded 2 million outstanding stock awards for the year ended December 31, 2023, which would be anti-dilutive. These stock awards could potentially dilute basic earnings per share in the future.

For the years ended December 31, 2022 and December 31, 2021, the calculation of diluted earnings per share excluded 5 million outstanding stock awards and 40 million shares underlying our March 2021 Equity Units because their impact would be anti-dilutive given the loss from continuing operations. These shares could potentially dilute basic earnings per share in the future. Had the Company generated income, potential shares of common stock of 3 million and 4 million related to the stock awards and 40 million and 33 million related to the Equity Units, would have been included in diluted weighted-average shares outstanding for the years ended December 31, 2022 and December 31, 2021, respectively.

As described in Note 17—*Equity*, the Company issued 10,430,500 Equity Units in March 2021 with a total notional value of $1,043 million. Each Equity Unit has a stated amount of $100 and was initially issued as a Corporate Unit, consisting of a 2024 Purchase Contract and a 10% undivided beneficial ownership interest in one share of Series A Preferred Stock. The conversion rate was initially 31.5428 shares of common stock per one share of Series A Preferred Stock, which was equivalent to an initial conversion price of approximately $31.70 per share of common stock. As of December 31, 2023, due to customary anti-dilution provisions, the conversion rate was 31.6795, equivalent to a conversion price of approximately $31.57 per share of common stock. The Series A Preferred Stock and the 2024 Purchase Contracts are being accounted for as one unit of account. In calculating diluted EPS, the Company has applied the if-converted method to determine the impact of the forward purchase feature and considered if there are incremental shares that should be included related to the Series A Preferred conversion value. On February 15, 2024, the Series A Preferred Stock was tendered to satisfy the Purchase Contract's settlement price and the Corporate Units were converted into shares of the Company's common stock at a settlement rate of 3.8859, equivalent to a reference price of $25.73. The Series A Preferred Stock was cancelled upon conversion.

27. RISKS AND UNCERTAINTIES

AES is a diversified power generation and utility company organized into four technology-based SBUs. See additional discussion of the Company's principal markets in Note 18—*Segments and Geographic Information*. Within our four SBUs, we have two primary lines of business: generation and utilities. The generation line of business uses a wide range of fuels and technologies to generate electricity such as coal, gas, hydro, wind, solar, and biomass. Our utilities business comprises businesses that transmit, distribute, and in certain circumstances, generate power. In addition, the Company has operations in the renewables area. These efforts include projects primarily in wind, solar, and energy storage.

Operating and Economic Risks — The Company operates in several developing economies where macroeconomic conditions are typically more volatile than developed economies. Deteriorating market conditions and evolving industry expectations to transition away from fossil fuel sources for generation expose the Company to the risk of decreased earnings and cash flows due to, among other factors, adverse fluctuations in the commodities and foreign currency spot markets, and potential changes in the estimated useful lives of our thermal plants. Additionally, credit markets around the globe continue to tighten their standards, which could impact our ability to finance growth projects through access to capital markets. Currently, the Company has an investment grade rating from both Standard & Poor's and Fitch of BBB- and an investment grade rating from Moody's of Baa3. A downgrade in our current investment grade ratings could affect the Company's ability to finance new and/or existing development projects at competitive interest rates. As of December 31, 2023, the Company had $1.4 billion of unrestricted cash and cash equivalents.

During 2023, 65% of our revenue was generated outside the U.S. and a significant portion of our international operations is conducted in developing countries. We continue to invest in several developing countries to expand our existing platform and operations. International operations, particularly the operation, financing, and development of projects in developing countries, entail significant risks and uncertainties, including, without limitation:

- economic, social, and political instability in any particular country or region;
- inability to economically hedge energy prices;
- volatility in commodity prices;
- adverse changes in currency exchange rates;
- government restrictions on converting currencies or repatriating funds;
- unexpected changes in foreign laws, regulatory framework, or in trade, monetary or fiscal policies;
- high inflation and monetary fluctuations;
- restrictions on imports of solar panels, wind turbines, coal, oil, gas, or other raw materials required by our generation businesses to operate;
- threatened or consummated expropriation or nationalization of our assets by foreign governments;
- unwillingness of governments, government agencies, similar organizations, or other counterparties to honor their commitments;
- unwillingness of governments, government agencies, courts, or similar bodies to enforce contracts that are economically advantageous to subsidiaries of the Company and economically unfavorable to

counterparties, against such counterparties, whether such counterparties are governments or private parties;

- inability to obtain access to fair and equitable political, regulatory, administrative, and legal systems;
- adverse changes in government tax policy;
- potentially adverse tax consequences of operating in multiple jurisdictions;
- difficulties in enforcing our contractual rights, enforcing judgments, or obtaining a just result in local jurisdictions; and
- inability to obtain financing on expected terms.

Any of these factors, individually or in combination with others, could materially and adversely affect our business, results of operations, and financial condition. In addition, our Latin American operations experience volatility in revenue and earnings which have caused and are expected to cause significant volatility in our results of operations and cash flows. The volatility is caused by regulatory and economic difficulties, political instability, indexation of certain PPAs to fuel prices, and currency fluctuations being experienced in many of these countries. This volatility reduces the predictability and enhances the uncertainty associated with cash flows from these businesses.

Our inability to predict, influence or respond appropriately to changes in law or regulatory schemes, including any inability to obtain reasonable increases in tariffs or tariff adjustments for increased expenses, could adversely impact our results of operations or our ability to meet publicly announced projections or analysts' expectations. Furthermore, changes in laws or regulations or changes in the application or interpretation of regulatory provisions in jurisdictions where we operate, particularly our utility businesses where electricity tariffs are subject to regulatory review or approval, could adversely affect our business, including, but not limited to:

- changes in the determination, definition, or classification of costs to be included as reimbursable or pass-through costs;
- changes in the definition or determination of controllable or noncontrollable costs;
- adverse changes in tax law;
- changes in the definition of events which may or may not qualify as changes in economic equilibrium;
- changes in the timing of tariff increases;
- other changes in the regulatory determinations under the relevant concessions; or
- changes in environmental regulations, including regulations relating to GHG emissions in any of our businesses.

Any of the above events may result in lower margins for the affected businesses, which can adversely affect our results of operations.

Puerto Rico — Earlier this year, AES Puerto Rico took certain measures to address identified liquidity challenges. On July 6, 2023, PREPA agreed to the release of funds in the escrow account guaranteeing AES Puerto Rico's obligations under the Power Purchase and Operating Agreement ("PPOA") in order to provide additional liquidity for the business. AES Puerto Rico continues to work with PREPA and its noteholders on these liquidity challenges. During Q4 2023, a restructuring support agreement was executed by AES Puerto Rico and its noteholders and a PPOA amendment was approved by PREPA. These agreements require Puerto Rico Energy Bureau ("PREB") approval to become effective. On February 2, 2024 a resolution was issued by PREB approving the PPOA amendment subject to the incorporation of certain additional terms and conditions. The Company expects the PPOA amendment and restructuring support agreement to become effective during the first quarter of 2024.

Despite these challenges and considering the information available as of the filing date, management believes the carrying amount of our long-lived assets at AES Puerto Rico of $76 million is recoverable as of December 31, 2023. However, it is reasonably possible that the estimate of undiscounted cash flows may change in the near term resulting in the need to write down our long-lived assets in Puerto Rico to fair value.

Foreign Currency Risks — AES operates businesses in many foreign countries and such operations could be impacted by significant fluctuations in foreign currency exchange rates. Fluctuations in currency exchange rate between the USD and the following currencies could create significant fluctuations in earnings and cash flows: the Argentine peso, the Brazilian real, the Chilean peso, the Colombian peso, the Dominican peso, the Euro, the Indian rupee, and the Mexican peso.

Concentrations — Due to the geographical diversity of its operations, the Company does not have any significant concentration of customers or sources of fuel supply. Several of the Company's generation businesses rely on PPAs with one or a limited number of customers for the majority of, and in some cases all of, the relevant businesses' output over the term of the PPAs. However, no single customer accounted for 10% or more of total revenue in 2023, 2022 or 2021.

The cash flows and results of operations of our businesses depend on the credit quality of our customers and the continued ability of our customers and suppliers to meet their obligations under PPAs and fuel supply agreements. If a substantial portion of the Company's long-term PPAs and/or fuel supply were modified or terminated, the Company would be adversely affected to the extent that it would be unable to replace such contracts at equally favorable terms.

28. RELATED PARTY TRANSACTIONS

Certain of our businesses in Panama and the Dominican Republic are partially owned by governments either directly or through state-owned institutions. In the ordinary course of business, these businesses enter into energy purchase and sale transactions, and transmission agreements with other state-owned institutions which are controlled by such governments. At two of our generation businesses in Mexico, the offtakers exercise significant influence, but not control, through representation on these businesses' Boards of Directors. These offtakers are also required to hold a nominal ownership interest in such businesses. Furthermore, in 2021, the Company began construction projects with Fluence relating to energy storage. These related party transactions primarily present themselves as construction in progress, as seen below. Additionally, the Company provides certain support and management services to several of its affiliates under various agreements.

The Company's Consolidated Statements of Operations included the following transactions with related parties for the periods indicated (in millions):

Years Ended December 31,	2023	2022	2021
Revenue—Non-Regulated	$ 1,055	$ 1,093	$ 1,159
Cost of Sales—Non-Regulated	576	352	324
Interest income	9	10	12
Interest expense	36	95	88

The following table summarizes the balances that relate to related party transactions for balance sheet accounts included in the Company's Consolidated Balance Sheets as of the periods indicated (in millions):

December 31,	2023	2022
Receivables from related parties	$ 584	$ 484
Accounts and notes payable to related parties (1)	1,411	1,264
Construction in progress	464	714

(1) Includes $639 million and $756 million of debt to Mong Duong Finance Holdings B.V., as of December 31, 2023 and 2022, respectively. Mong Duong was classified as held-for-sale in December 2023 (see Note 11—*Debt*).

29. SUBSEQUENT EVENTS

Warrior Run — On February 1, 2024, Warrior Run closed on a Sale and Assignment Agreement, in which the remaining future cash flows from the Warrior Run PPA termination agreement (see Note 20—*Revenue*) were assigned to a third party. In return, Warrior Run received approximately $273 million in proceeds, which were used primarily to repay existing indebtedness and for general corporate purposes. The net proceeds from this transaction will be included in *Non-recourse debt* on the Consolidated Balance Sheets until June 2024.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in the reports that the Company files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act") is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosures.

The Company carried out the evaluation required by Rules 13a-15(b) and 15d-15(b), under the supervision and with the participation of our management, including the CEO and CFO, of the effectiveness of our “disclosure controls and procedures” (as defined in the Exchange Act Rules 13a-15(e) and 15d-15(e)). Based upon this evaluation, the CEO and CFO concluded that as of December 31, 2023, our disclosure controls and procedures were effective.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) under the Exchange Act. The 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 GAAP and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and
- provide reasonable assurance that unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements are prevented or detected timely.

Management, including our CEO and CFO, does not expect that our internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. In addition, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, or that the degree of compliance with the policies or procedures deteriorates.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2023. In making this assessment, management used the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in 2013. Based on this assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2023.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2023, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which appears herein.

Changes in Internal Control Over Financial Reporting:

There were no changes that occurred during the quarter ended December 31, 2023 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of The AES Corporation

Opinion on Internal Control over Financial Reporting

We have audited The AES Corporation's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, The AES Corporation (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2023 and 2022, the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2023, and the related notes and the financial statement schedule listed in the Index at Item 15(c) and our report dated February 26, 2024 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's 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/ Ernst & Young LLP

Tysons, Virginia
February 26, 2024

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The following information is incorporated by reference from the Registrant's Proxy Statement for the Registrant's 2024 Annual Meeting of Stockholders which the Registrant expects will be filed on or around March 14, 2024 (the "2024 Proxy Statement"):

- information regarding the directors required by this item found under the heading *Board of Directors - Biographies*;
- information regarding AES' Code of Ethics found under the heading *Corporate Governance at AES - Additional Governance Information*; and
- information regarding AES' Financial Audit Committee found under the heading *Board and Committee Governance - Board Committees - Financial Audit Committee (the "Audit Committee").*

Certain information regarding executive officers required by this Item is presented as a supplementary item in Part I hereof (pursuant to Instruction 3 to Item 401(b) of Regulation S-K). The other information required by this Item, to the extent not included above, will be contained in our 2024 Proxy Statement and is herein incorporated by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 402 of Regulation S-K will be contained in the 2024 Proxy Statement under "Director Compensation" and "Executive Compensation" (excluding the information under the caption "Compensation Committee Report") and is incorporated herein by reference.

The information required by Item 407(e)(5) of Regulation S-K will be contained under the caption "Compensation Committee Report" of the Proxy Statement. Such information shall not be deemed to be "filed."

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

(a) *Security Ownership of Certain Beneficial Owners and Management.*

See the information contained under the heading *Security Ownership of Certain Beneficial Owners, Directors, and Executive Officers* of the 2024 Proxy Statement, which information is incorporated herein by reference.

(b) *Securities Authorized for Issuance under Equity Compensation Plans.*

The following table provides information about shares of AES common stock that may be issued under AES' equity compensation plans, as of December 31, 2023:

Securities Authorized for Issuance under Equity Compensation Plans (As of December 31, 2023)

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders [1]	5,633,037 [2]	$ 13.60	11,153,030
Equity compensation plans not approved by security holders	—	—	—
Total	5,633,037	$ 13.70	11,153,030

[1] The following equity compensation plans have been approved by The AES Corporation's Stockholders:

[a] The AES Corporation 2003 Long Term Compensation Plan was adopted in 2003 and provided for 17,000,000 shares authorized for issuance thereunder. In 2008, an amendment to the Plan to provide an additional 12,000,000 shares was approved by AES' stockholders, bringing the total authorized shares to 29,000,000. In 2010, an additional amendment to the Plan to provide an additional 9,000,000 shares was approved by AES' stockholders, bringing the total authorized shares to 38,000,000. In 2015, an additional amendment to the Plan to provide an additional 7,750,000 shares was approved by AES' stockholders, bringing the total authorized shares to 45,750,000. The weighted average exercise price of Options outstanding under this plan included in Column (b) is $13.60 (excluding performance stock units, restricted stock units and director stock units), with 11,153,030 shares available for future issuance.

[b] The AES Corporation Second Amended and Restated Deferred Compensation Plan for directors provided for 2,000,000 shares authorized for issuance. Column (b) excludes the Director stock units granted thereunder. In conjunction with the 2010 amendment to the 2003 Long Term Compensation Plan, ongoing award issuance from this plan was discontinued in 2010 as Director stock units will be issued from the 2003 Long Term Compensation Plan. Any remaining shares under this plan, which are not reserved for

issuance under outstanding awards, are not available for future issuance and thus the amount of 105,341 shares is not included in Column (c) above.

(2) Includes 3,435,116 (of which 330,522 are vested and 3,104,594 are unvested) shares underlying PSU and RSU awards (assuming 2021, 2022 and 2023 PSUs maximum performance), 1,477,308 shares underlying Director stock unit awards, and 720,613 shares issuable upon the exercise of Stock Option grants, for an aggregate number of 5,633,037 shares.

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

The information regarding related party transactions required by this item will be included in the 2024 Proxy Statement found under the headings *Related Person Policies and Procedures* and *Board and Committee Governance* and are incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item 14 will be included in the 2024 Proxy Statement under the headings *Information Regarding The Independent Registered Public Accounting Firm, Audit Fees, Audit Related Fees, and Pre-Approval Policies and Procedures* and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) *Financial Statements.*

(b) *Exhibits.*

3.1	Sixth Restated Certificate of Incorporation of The AES Corporation is incorporated herein by reference to Exhibit 3.1 of the Company's Form 10-K for the year ended December 31, 2008.
3.2	Amended and Restated By-Laws of The AES Corporation, incorporated herein by reference to Exhibit 3.2 of the Company's Form 10-Q for the quarter ended June 30, 2023.
4	There are numerous instruments defining the rights of holders of long-term indebtedness of the Registrant and its consolidated subsidiaries, none of which exceeds ten percent of the total assets of the Registrant and its subsidiaries on a consolidated basis. The Registrant hereby agrees to furnish a copy of any of such agreements to the Commission upon request. Since these documents are not required filings under Item 601 of Regulation S-K, the Company has elected to file certain of these documents as Exhibits 4.(a)—4.(i).
4.(a)	Senior Indenture, dated as of December 8, 1998, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association (formerly known as The First National Bank of Chicago) is incorporated herein by reference to Exhibit 4.01 of the Company's Form 8-K filed on December 11, 1998 (SEC File No. 001-12291).
4.(b)	Ninth Supplemental Indenture, dated as of April 3, 2003, between The AES Corporation and Wells Fargo Bank, National Association (as successor by consolidation to Wells Fargo Bank Minnesota, National Association) is incorporated herein by reference to Exhibit 4.6 of the Company's Form S-4 filed on December 7, 2007.
4.(c)	Twenty-Fourth Supplemental Indenture, dated March 15, 2018, between The AES Corporation and Deutsche Bank Trust Company Americas, as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on March 21, 2018.
4.(d)	Indenture, dated May 27, 2020, between The AES Corporation and Deutsche Bank Trust Company Americas, as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on May 27, 2020.
4.(e)	Twenty-Fifth Supplemental Indenture, dated June 5, 2020, between The AES Corporation and Deutsche Bank Trust Company Americas, as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on June 8, 2020.
4.(f)	Twenty-Sixth Supplemental Indenture, dated December 4, 2020, between The AES Corporation and Deutsche Bank Trust Company Americas, as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on December 4, 2020.
4.(g)	Twenty-Seventh Supplemental Indenture, dated December 7, 2020, between The AES Corporation and Deutsche Bank Trust Company Americas, as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on December 7, 2020.
4.(h)	Twenty-Eighth Supplemental Indenture, dated May 17, 2023, between The AES Corporation and Deutsche Bank Trust Company Americas, as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on May 17, 2023.
4.(i)	Description of the Registrant's Securities is incorporated herein by reference to Exhibit 4.(k) of the Company's Form 10-K for the year ended December 31, 2020.is incorporated herein by reference to Exhibit 4.(k) of the Company's Form 10-K for the year ended December 31, 2020.
10.1	Deferred Compensation Plan for Directors, as amended and restated, on February 17, 2012 is incorporated herein by reference to Exhibit 10.5 of the Company's Form 10-K for the year ended December 31, 2012.
10.2	The AES Corporation Stock Option Plan for Outside Directors, as amended and restated, on December 7, 2007 is incorporated herein by reference to Exhibit 10.6 of the Company's Form 10-K for the year ended December 31, 2012.
10.3	Second Amended and Restated Deferred Compensation Plan for Directors is incorporated herein by reference to Exhibit 10.13 of the Company's Form 10-K for the year ended December 31, 2000 (SEC File No. 001-12291).
10.4	The AES Corporation 2001 Non-Officer Stock Option Plan is incorporated herein by reference to Exhibit 10.12 of the Company's Form 10-K for the year ended December 31, 2002 (SEC File No. 001-12291).
10.5	The AES Corporation 2003 Long Term Compensation Plan, as Amended and Restated, dated October 11, 2023 (filed herewith).
10.6	Form of AES Nonqualified Stock Option Award Agreement under The AES Corporation 2003 Long Term Compensation Plan (Outside Directors) is incorporated herein by reference to Exhibit 10.2 of the Company's Form 8-K filed on April 27, 2010.
10.7	Form of AES Performance Stock Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan for the year ended December 31, 2023 (filed herewith)
10.8	Form of AES Restricted Stock Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan for the year ended December 31, 2023 (filed herewith).

10.9	Form of AES Performance Cash Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan for the year ended December 31, 2023 (filed herewith).
10.10	Form of AES Nonqualified Stock Option Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.4 of the Company's Form 10-Q for the quarter ended June 30, 2015.
10.11	Form of AES Performance Cash Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan for the year ended December 31, 2023 (filed herewith).
10.12	The AES Corporation Restoration Supplemental Retirement Plan, as amended and restated, effective October 10, 2023 (filed herewith).
10.13	The AES Corporation International Retirement Plan, as amended and restated on December 29, 2008 is incorporated herein by reference to Exhibit 10.16 of the Company's Form 10-K for the year ended December 31, 2008.
10.13A	Amendment to The AES Corporation International Retirement Plan, dated December 9, 2011 is incorporated herein by reference to Exhibit 10.18A of the Company's Form 10-K for the year ended December 31, 2012.
10.14	The AES Corporation Amended and Restated Executive Severance Plan and Summary Plan Description dated October 10, 2023 (filed herewith).
10.15	The AES Corporation Performance Incentive Plan, as Amended and Restated on October 10, 2023.
10.16	The AES Corporation Deferred Compensation Program For Directors dated February 17, 2012 is incorporated herein by reference to Exhibit 10.22 of the Company's Form 10-K filed on December 31, 2011.
10.17	Form of Retroactive Consent to Provide for Double-Trigger Change-In-Control Transactions is incorporated herein by reference to Exhibit 10.7 of the Company's Form 10-Q for the period ended June 30, 2015.
10.18	Seventh Amended and Restated Credit and Reimbursement Agreement dated as of December 20, 2019 among The AES Corporation, a Delaware corporation, the Banks listed on the signature pages thereof, Citibank, N.A., as Administrative Agent and Collateral Agent, and Citibank, N.A., Mizuho Bank Ltd. and Crédit Agricole Corporate and Investment Bank, as Joint Lead Arrangers and Joint Book Runners is incorporated herein by reference to Exhibit 10.1.A of the Company's Form 8-K filed on December 23, 2019.
10.19	Eight Amended and Restated Credit Agreement dated as of September 24, 2021 among The AES Corporation, a Delaware corporation, the lenders listed on the signature pages thereof, Citibank, N.A., as Administrative Agent and Citibank, N.A., Mizuho Bank Ltd. and Sumitomo Mitsui Banking Corporation, as Joint Lead Arrangers, incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on September 28, 2021 (SEC File No. 001-12291).
10.20	Form of Director and Officer Indemnification Agreement is incorporated herein by reference to Exhibit 10.30 of the Company's Form 10-Q for the period ended September 30, 2022.
10.21	Amendment No. 1 to the Credit Agreement dated as of August 23, 2022 among The AES Corporation, a Delaware corporation, the lenders listed on the signature pages thereof, and Citibank, N.A., as Administrative Agent is incorporated herein by reference to Exhibit 10.31 of the Company's Form 10-Q for the period ended September 30, 2022.
10.22	Term Loan Agreement dated as of September 30, 2022 among The AES Corporation as Borrower, the banks named herein as Banks, and Sumitomo Mitsui Banking Corporation as Administrative Agent is incorporated herein by reference to Exhibit 10.32 of the Company's Form 10-Q for the period ended September 30, 2022.
10.23	Form of AES Non-Executive Restricted Stock Unit Award Agreement under the AES Corporation 2003 Long Term Compensation Plan for the year ended December 31, 2023 (filed herewith).
21.1	Subsidiaries of The AES Corporation (filed herewith).
23.1	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP (filed herewith).
24	Powers of Attorney (filed herewith).
31.1	Rule 13a-14(a)/15d-14(a) Certification of Andrés Gluski (filed herewith).
31.2	Rule 13a-14(a)/15d-14(a) Certification of Stephen Coughlin (filed herewith).
32.1	Section 1350 Certification of Andrés Gluski (filed herewith).
32.2	Section 1350 Certification of Stephen Coughlin (filed herewith).
97	Amended and Restated Compensation Recoupment Policy, effective October 6, 2023.
101	The AES Corporation Annual Report on Form 10-K for the year ended December 31, 2022, formatted in Inline XBRL (Inline Extensible Business Reporting Language): (i) the Cover Page, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Operations, (iv) Consolidated Statements of Comprehensive Income (Loss), (v) Consolidated Statements of Changes in Equity, (vi) Consolidated Statements of Cash Flows, and (vii) Notes to Consolidated Financial Statements. The instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

(c) *Schedule*

Schedule I—Financial Information of Registrant

SIGNATURES

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

THE AES CORPORATION
(Company)

Date: February 26, 2024

By: /s/ ANDRÉS GLUSKI
Name: Andrés Gluski
President, Chief Executive Officer

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

Name	Title	Date
* **Andrés Gluski**	President, Chief Executive Officer (Principal Executive Officer) and Director	February 26, 2024
* **Gerard M. Anderson**	Director	February 26, 2024
* **Inderpal S. Bhandari**	Director	February 26, 2024
* **Janet G. Davidson**	Director	February 26, 2024
* **Tarun Khanna**	Director	February 26, 2024
* **Holly K. Koeppel**	Director	February 26, 2024
* **Julia M. Laulis**	Director	February 26, 2024
* **Alain Monié**	Director	February 26, 2024
* **John B. Morse**	Chairman of the Board and Lead Independent Director	February 26, 2024
* **Moisés Naím**	Director	February 26, 2024
* **Teresa M. Sebastian**	Director	February 26, 2024
* **Maura Shaughnessy**	Director	February 26, 2024
/s/ STEPHEN COUGHLIN **Stephen Coughlin**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2024
/s/ SHERRY L. KOHAN **Sherry L. Kohan**	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 26, 2024

*By: /s/ PAUL L. FREEDMAN — February 26, 2024
Attorney-in-fact

THE AES CORPORATION AND SUBSIDIARIES

INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedules other than that listed above are omitted as the information is either not applicable, not required, or has been furnished in the consolidated financial statements or notes thereto included in Item 8 hereof.

See Notes to Schedule I

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
BALANCE SHEETS

DECEMBER 31, 2023 AND 2022

	December 31, 2023	December 31, 2022
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 33	$ 24
Accounts and notes receivable from subsidiaries	1,248	169
Prepaid expenses and other current assets	51	47
Total current assets	1,332	240
Investment in and advances to subsidiaries and affiliates	6,735	7,204
Office Equipment:		
Cost	14	16
Accumulated depreciation	(12)	(10)
Office equipment, net	2	6
Other Assets:		
Deferred financing costs, net of accumulated amortization of $11 and $9, respectively	6	8
Other assets	44	117
Total other assets	50	125
Total assets	$ 8,119	$ 7,575
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 44	$ 33
Accounts and notes payable to subsidiaries	273	609
Accrued and other liabilities	284	319
Senior notes payable—current portion	200	—
Total current liabilities	801	961
Long-term Liabilities:		
Debt	4,264	3,894
Accounts and notes payable to subsidiaries	158	—
Other long-term liabilities	408	283
Total long-term liabilities	4,830	4,177
Stockholders' equity:		
Preferred stock	838	838
Common stock	8	8
Additional paid-in capital	6,355	6,688
Accumulated deficit	(1,386)	(1,635)
Accumulated other comprehensive loss	(1,514)	(1,640)
Treasury stock	(1,813)	(1,822)
Total stockholders' equity	2,488	2,437
Total liabilities and equity	$ 8,119	$ 7,575

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF OPERATIONS

YEARS ENDED DECEMBER 31, 2023, 2022, AND 2021

For the Years Ended December 31,	2023	2022	2021
		(in millions)	
Revenue from subsidiaries and affiliates	$ 31	$ 30	$ 28
Equity in earnings of subsidiaries and affiliates	598	(280)	(47)
Interest income	44	28	20
General and administrative expenses	(129)	(140)	(121)
Other income	11	14	51
Other expense	—	—	(65)
Interest expense	(230)	(163)	(74)
Income (loss) before income taxes	325	(511)	(208)
Income tax expense	(76)	(35)	(201)
Net income (loss)	$ 249	$ (546)	$ (409)

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

YEARS ENDED DECEMBER 31, 2023, 2022, AND 2021

	2023	2022	2021
		(in millions)	
NET INCOME (LOSS)	$ 249	$ (546)	$ (409)
Foreign currency translation activity:			
Foreign currency translation adjustments, net of $0 income tax for all periods	136	(37)	(86)
Reclassification to earnings, net of $0 income tax for all periods	—	—	3
Total foreign currency translation adjustments, net of tax	136	(37)	(83)
Derivative activity:			
Change in derivative fair value, net of income tax benefit (expense) of $(7), $(198) and $8, respectively	55	645	(7)
Reclassification to earnings, net of income tax benefit (expense) of $9, $0 and $(73), respectively	(52)	44	254
Total change in fair value of derivatives, net of tax	3	689	247
Pension activity:			
Prior service cost for the period, net of $0 income tax for all periods	1	—	—
Change in pension adjustments due to net actuarial gain (loss) for the period, net of income tax (expense) benefit of $1, $(2) and $(9), respectively	(4)	10	23
Reclassification of earnings, net of income tax expense of $0, $1 and $3, respectively	—	—	1
Total change in unfunded pension obligation	(3)	10	24
OTHER COMPREHENSIVE INCOME	136	662	188
COMPREHENSIVE INCOME (LOSS)	$ 385	$ 116	$ (221)

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF CASH FLOWS

YEARS ENDED DECEMBER 31, 2023, 2022, AND 2021

For the Years Ended December 31,	2023	2022	2021
		(in millions)	
Net cash provided by operating activities	$ 608	$ 434	$ 570
Investing Activities:			
Proceeds from the sale of business interests, net of expenses	474	157	64
Investment in and net advances to subsidiaries	(2,187)	(1,716)	(2,260)
Return of capital	1,185	907	698
Additions to property, plant and equipment	(9)	(10)	(14)
Net cash used in investing activities	(537)	(662)	(1,512)
Financing Activities:			
(Repayments) borrowings under the revolver, net	(325)	(40)	295
Borrowings of notes payable and other coupon bearing securities	900	200	—
Loans from (repayments to) subsidiaries	(177)	465	—
Issuance of preferred stock	—	—	1,014
Proceeds from issuance of common stock	1	15	8
Common stock dividends paid	(444)	(422)	(401)
Payments for deferred financing costs	(14)	(4)	(4)
Sales to noncontrolling interests	—	—	(1)
Other financing	(3)	(2)	1
Net cash provided by (used in) financing activities	(62)	212	912
Increase (decrease) in cash and cash equivalents	9	(16)	(30)
Cash and cash equivalents, beginning	24	40	70
Cash and cash equivalents, ending	$ 33	$ 24	$ 40
Supplemental Disclosures:			
Cash payments for interest, net of amounts capitalized	$ 178	$ 125	$ 79
Cash payments for income taxes, net of refunds	9	1	—

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I
NOTES TO SCHEDULE I

1. Application of Significant Accounting Principles

The Schedule I Condensed Financial Information of the Parent includes the accounts of The AES Corporation (the "Parent Company") and certain holding companies.

ACCOUNTING FOR SUBSIDIARIES AND AFFILIATES — The Parent Company has accounted for the earnings of its subsidiaries on the equity method in the financial information.

INCOME TAXES — Positions taken on the Parent Company's income tax return which satisfy a more-likely-than-not threshold will be recognized in the financial statements. The income tax expense or benefit computed for the Parent Company reflects the tax assets and liabilities on a stand-alone basis and the effect of filing a consolidated U.S. income tax return with certain other affiliated companies.

ACCOUNTS AND NOTES RECEIVABLE FROM SUBSIDIARIES — Amounts have been shown in current or long-term assets based on terms in agreements with subsidiaries, but payment is dependent upon meeting conditions precedent in the subsidiary loan agreements.

2. Debt

Senior and Unsecured Notes and Loans Payable ($ in millions)

	Interest Rate	Maturity	December 31, 2023	2022
Senior Variable Rate Term Loan	SOFR + 1.125%	2024	$ 200	$ 200
Senior Unsecured Note	3.30%	2025	900	900
Senior Unsecured Note	1.375%	2026	800	800
Drawings on revolving credit facility	SOFR + 1.75%	2027	—	325
Senior Unsecured Note	5.45%	2028	900	—
Senior Unsecured Note	3.95%	2030	700	700
Senior Unsecured Note	2.45%	2031	1,000	1,000
Unamortized (discounts)/premiums & debt issuance (costs)			(36)	(31)
Subtotal			$ 4,464	$ 3,894
Less: Current maturities			(200)	—
Noncurrent maturities			$ 4,264	$ 3,894

FUTURE MATURITIES OF RECOURSE DEBT — As of December 31, 2023 scheduled maturities are presented in the following table (in millions):

December 31,	Annual Maturities
2024	$ 200
2025	900
2026	800
2027	—
2028	900
Thereafter	1,700
Unamortized (discount)/premium & debt issuance (costs), net	(36)
Total debt	$ 4,464

3. Dividends from Subsidiaries and Affiliates

Cash dividends received from consolidated subsidiaries were $1.4 billion, $832 million, and $894 million for the years ended December 31, 2023, 2022, and 2021, respectively. For the years ended December 31, 2023, 2022, and 2021, $474 million, $157 million, and $65 million, respectively, of the dividends paid to the Parent Company are derived from the sale of business interests and are classified as an investing activity for cash flow purposes. All other dividends are classified as operating activities. There were no cash dividends received from affiliates accounted for by the equity method for the years ended December 31, 2023, 2022, and 2021.

4. Guarantees and Letters of Credit

GUARANTEES — In connection with certain project financing, acquisitions and dispositions, power purchases and other agreements, the Parent Company has expressly undertaken limited obligations and commitments, most of which will only be effective or will be terminated upon the occurrence of future events. These obligations and commitments, excluding those collateralized by letter of credit and other obligations discussed below, were limited as of December 31, 2023 by the terms of the agreements, to an aggregate of approximately $4 billion, representing 90 agreements with individual exposures ranging up to $970 million. These amounts exclude normal and customary representations and warranties in agreements for the sale of assets (including ownership in associated legal entities) where the associated risk is considered to be nominal.

LETTERS OF CREDIT — At December 31, 2023, the Parent Company had $124 million in letters of credit outstanding under the revolving credit facility, representing 17 agreements with individual exposures up to $40 million; $188 million in letters of credit outstanding under the unsecured credit facilities, representing 31 agreements with individual exposures ranging up to $70 million; and $235 million in letters of credit outstanding under bilateral agreements, representing 4 agreements with individual exposures ranging up to $64 million. During the year ended December 31, 2023, the Parent Company paid letter of credit fees ranging from 1% to 3% per annum on the outstanding amounts.