2025

Annual report

Accelerating the future of energy, together

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, 2025

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates on June 30, 2025, the last business day of the Registrant's most recently completed second fiscal quarter (based on the closing sale price of $10.52 of the Registrant's Common Stock, as reported by the New York Stock Exchange on such date) was approximately $7.49 billion.

The number of shares outstanding of Registrant's Common Stock, par value $0.01 per share, on February 26, 2026 was 712,558,860.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Registrant's Proxy Statement for its 2026 annual meeting of stockholders are incorporated by reference in Parts II and III

The AES Corporation Fiscal Year 2025 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:

2024 Base Rate Order	The order issued in April 2024 by the IURC authorizing AES Indiana to, among other things, increase its basic rates and charges by $71 million annually
2024 DRC Settlement	The order issued in November 2025 by the PUCO authorizing AES Ohio to, among other things, increase its basic rates and charges by $168 million annually
Adjusted EBITDA	Adjusted earnings before interest income and expense, taxes, depreciation, amortization, and accretion of AROs, a non-GAAP measure of operating performance
Adjusted EBITDA with Tax Attributes	Adjusted earnings before interest income and expense, taxes, depreciation, amortization, and accretion of AROs, adding back the pre-tax effect of Production Tax Credits, Investment Tax Credits, 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, 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 Energia S.A.
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. For the periods covered by this report, AES Ohio was wholly-owned by DPL. Beginning in April 2025, CDPQ owns an aggregate indirect equity interest in AES Ohio of approximately 30%.
AES Renewable Holdings	AES Renewable Holdings, LLC, formerly branded as AES Distributed Energy
AFUDC	Allowance for Funds Used During Construction
ANEEL	Brazilian National Electric Energy Agency
AOCL	Accumulated Other Comprehensive Loss
ARO	Asset Retirement Obligations
ASC	Accounting Standards Codification
BESS	Battery Energy Storage System
BOT	Build, Operate and Transfer
CAA	U.S. Clean Air Act
CAMMESA	Wholesale Electric Market Administrator in Argentina
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals, which include bottom ash, fly ash, and air pollution control wastes generated at coal-fired generation plant sites
CDPQ	La Caisse de dépôt et placement du Québec
CECL	Current Expected Credit Loss
CEO	Chief Executive Officer
CFE	Federal Electricity Commission in Mexico
CFO	Chief Financial Officer
CO_2	Carbon Dioxide
CPI	U.S. Consumer Price Index
CSAPR	U.S. Cross-State Air Pollution Rule
CWA	U.S. Clean Water Act
CWIP	Construction Work In Progress
DG Comp	Directorate-General for Competition of the European Commission
DPL	DPL LLC and its consolidated subsidiaries. On April 3, 2025, DPL Inc. converted its form of business organization from an Ohio corporation to an Ohio limited liability company. Upon the conversion, DPL Inc. changed its name to DPL LLC. References to DPL are to DPL Inc. before April 3, 2025, and DPL LLC on and after April 3, 2025.
DPP	Dominican Power Partners
EBITDA	Earnings before interest income and expense, taxes, depreciation, amortization, and accretion of AROs, a non-GAAP measure of operating performance
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
ESP	Electric Security Plan
EU	European Union
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
GW	Gigawatts
GWh	Gigawatt Hours
HLBV	Hypothetical Liquidation Book Value
IPALCO	IPALCO Enterprises, Inc. CDPQ owns direct and indirect interests in IPALCO of approximately 30%.
IPP	Independent Power Producers
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
LGR	Legacy Generation Resource Rider
LNG	Liquefied Natural Gas
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British Thermal Units
MRO	Market Rate Option, a market-based plan that a utility may file with PUCO to establish SSO rates pursuant to Ohio law
MW	Megawatts
MWh	Megawatt Hours
NAAQS	U.S. National Ambient Air Quality Standards
NCI	Noncontrolling Interest
NCTI	Net Controlled Foreign Corporation Tested Income
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
OCC	Ohio Consumers' Counsel (statewide legal representative for Ohio's residential consumers and advocates on their behalf in PUCO and Ohio Supreme Court proceedings)
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
REC	Renewable Energy Credit
RSU	Restricted Stock Unit
RTO	Regional Transmission Organization
SADI	Argentine Interconnected System
SBU	Strategic Business Unit
SEC	U.S. Securities and Exchange Commission
SEET	Significantly Excessive Earnings Test
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
TDSIC	Transmission, Distribution, and Storage System Improvement Charge
U.S.	United States
USD	United States Dollar
VIE	Variable Interest Entity
Vinacomin	Vietnam National Coal and Mineral Industries Holding Corporation Limited

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 facilities 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, transmission and distribution 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 control over financial reporting;
- our ability to remediate the material weakness described in Item 9A;
- 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.

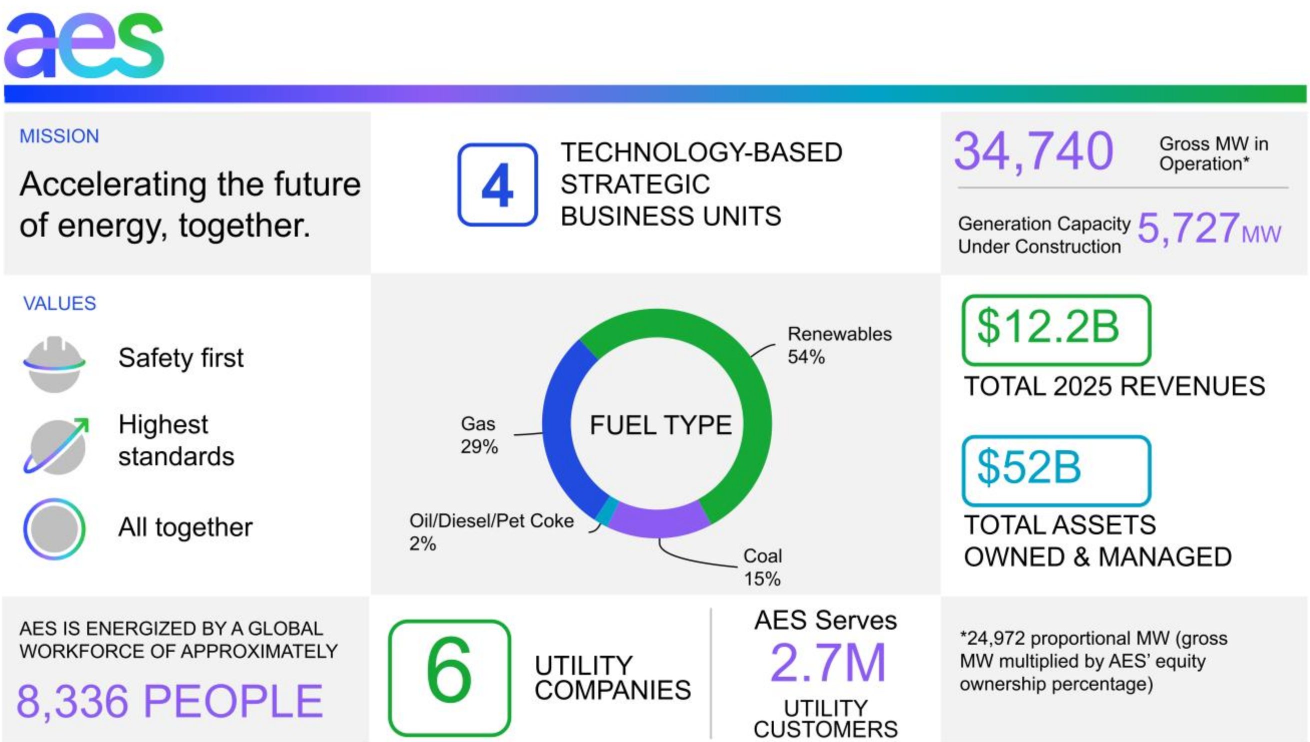
We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise. If one or more forward-looking statements are updated, no inference should be drawn that additional updates will be made with respect to those or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



Our Strategy

AES is the next-generation energy company with over four decades of experience developing, operating, and owning electric generation and utilities.

The focus of our strategy is to partner with large corporations to deliver the electricity they need when they need it. We are very well-positioned as a leading provider of renewable energy to data center companies, particularly in the U.S., and to large mining companies outside the U.S. These customers want to work with AES due to our track record of providing customized solutions that best serve their specific needs and delivering our projects on time and on budget.

In 2025, we signed long-term contracts for 4.0 GW of renewables, bringing our backlog of projects — those with signed contracts, but which are not yet in operation — to 12.0 GW. Our backlog serves as one of the core components of our future growth. As a result of our successful execution of our strategy, 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.

At the same time, we have embarked on the most ambitious investment growth in the history of our U.S. utilities, which will improve the reliability and quality of service for our customers, while maintaining some of the lowest rates in both states where our utilities operate. AES Indiana and AES Ohio are now two of the fastest growth U.S. utilities, with projected double-digit rate base growth through 2027, based on necessary investments for our customers.

We are also seeing additional investment opportunities from data center growth in our utility service areas, above and beyond existing rate base projections. Our utilities have many natural advantages that are attractive to large technology companies, such as proximity to fiber networks and the presence of ample land and water. We have worked to proactively identify sites that are well-positioned to support new data centers, capitalizing on our deep relationships with technology companies.

2025 Strategic Highlights

- Our backlog, which consists of projects with signed contracts, but which are not yet operational, is 12.0 GW, including 5.7 GW under construction. In full year 2025, we:
  - Completed the construction of 3.2 GW of solar, energy storage, and wind; and
  - Signed or were awarded new long-term PPAs for 4.0 GW of renewables.
- At AES Indiana, filed with the IURC a partial settlement agreement for current rate review, as well as a 20-year IRP.
- At AES Ohio, received PUCO approval for its distribution rate case and filed for new multi-year base distribution rates for 2027 through 2029.
- With the sale of a minority interest in AGIC for $450 million in the first quarter of 2025, we achieved our full year 2025 asset sale proceeds target of $400 to $500 million.

Overview

Generation

We currently own and/or operate a generation portfolio of 34,740 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 and associated generation attributes under medium- or long-term contracts ("PPAs") 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. These contract sales and short-term sales may also include RECs, as discussed below.

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.

Our renewable energy generation businesses may also sell RECs under short-term contracts, either through bilateral sales or over commodity exchanges.

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 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.

54% of the capacity of our generation plants is fueled by renewables, including solar, hydro, wind, energy storage, and landfill gas, which do not have significant fuel costs.

29% of the capacity of our generation plants is 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.

15% 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 2.7 million customers and AES' two utilities in the U.S. also include generation capacity totaling 4,056 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 businesses in El Salvador face 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 businesses, 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, such as the U.S. and Chile, 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. For some development projects, rather than advancing them through construction and maintaining long-term ownership of an operating facility, AES may monetize project value by entering into Develop-Transfer Agreements ("DTAs") in which we transfer assets to a third party prior to construction in exchange for appropriate compensation. AES also provides development services, where we enter into contracts to fully develop customized assets to meet customers' needs. These DTAs and development service contracts may be entered into for new generation facilities or other potential uses of our development assets, including for data centers.

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

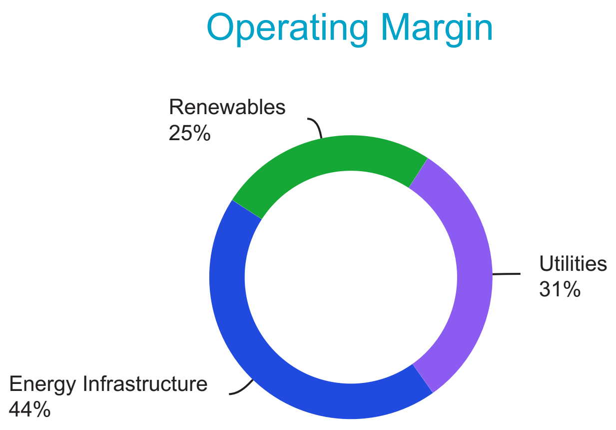
The segment reporting structure uses the Company's management reporting structure as its foundation to reflect how the Company manages the businesses internally and is mainly organized by technology.

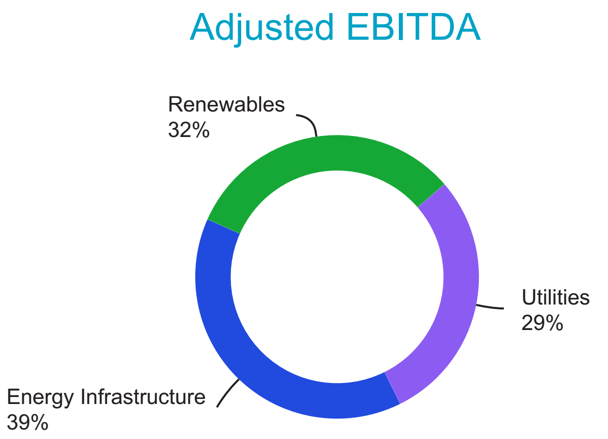
We are organized into four technology-oriented SBUs: **Renewables** (solar, wind, energy storage, and hydro generation facilities); **Utilities** (AES Indiana, AES Ohio, and AES El Salvador regulated utilities and their generation facilities); **Energy Infrastructure** (natural gas, LNG, coal, pet coke, diesel, and oil generation facilities); and **New Energy Technologies** (investments in Fluence, Maximo and other new and innovative energy technology businesses) — 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, transmit, distribute, 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, 2025 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,

2025. 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.





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 19—*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.

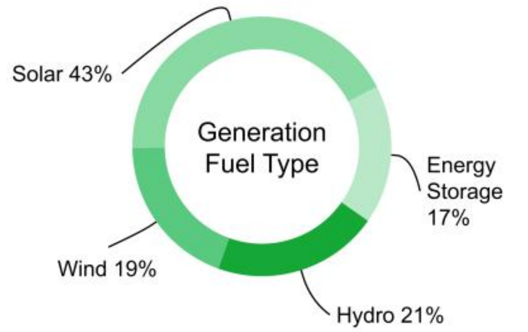
Renewables

Business Overview

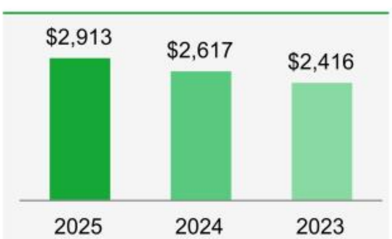
114 Generation Facilities

17,836 Gross MW

Key Generation Businesses: **U.S. Renewables and AES Andes**



Revenue
(In millions)



Operating Margin
(in millions)

Adjusted EBITDA [(1)]
(in millions)

Key events in 2025

- Completed construction of 2.7 GW of new renewables
- Signed or awarded long-term PPAs for 3.7 GW of new renewables

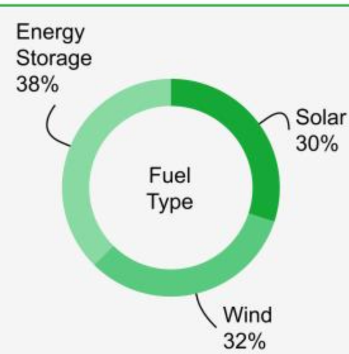
Strategic outlook

- Total backlog of 11.5 GW of renewables under signed long-term PPAs

Under construction

17 Plants

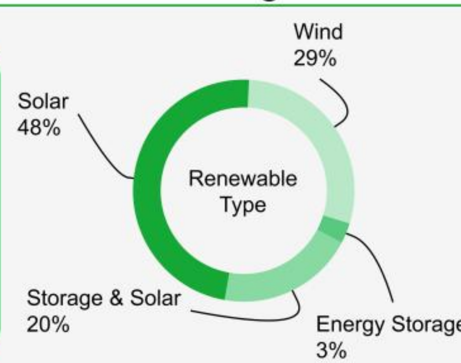
5,502 MW



Contracted renewable backlog

11,516 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.

Renewables

Our Renewables SBU is well-positioned to take advantage of the growth in data centers driven by the increase in power demand for generative artificial intelligence. In 2025, our assets in operation grew to 17.8 GW, and we added an incremental 3.7 GW to our backlog of contracted projects.

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

Generation — Total operating installed capacity of the Renewables SBU is 17,836 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)
OpCo A (1)	US-Various	Solar	967	26 %	2017-2019	2028-2046	Various
		Wind	140				
Alicura (2)	Argentina	Hydro	1,050	100 %	2000		
Chivor	Colombia	Hydro	1,000	99 %	2000	2026-2039	Various
Bellefield 1	US-CA	Solar	500	75 %	2025	2040	Amazon
		Energy Storage	500				
New York Wind (OpCo D) (3)	US-NY	Wind	612	75 %	2021		NYISO
Rexford (OpCo E) (3)	US-CA	Solar	300	100 %	2024	2039	Clean Power Alliance of Southern California
		Energy Storage	240				
Alto Maipo	Chile	Hydro	531	99 %	2021	2040	Minera Los Pelambres
OpCo E (3)	US-Various	Solar	420	100 %	2015-2025	2029-2045	Various
		Energy Storage	78				
Spotsylvania Solar Energy Center (1) (3)	US-VA	Solar	485	50 %	2020-2021	2035	Apple, Akamai, Etsy, Microsoft
Chevelon Butte (OpCo D) (3)	US-AZ	Wind	454	75 %	2023-2024	2043-2044	APS
McFarland B (OpCo D) (3)	US-AZ	Solar	300	75 %	2023-2024	2043	Amazon
		Energy Storage	150				
West Camp (OpCo D) (3)	US-AZ	Wind	420	75 %	2025	2045	APS
Andes Solar 3	Chile	Solar	171	100 %	2025	2040	Codelco
		Energy Storage	171				
Andes Solar 4	Chile	Solar	211	51 %	2023-2024	2026-2042	Google, Various
		Energy Storage	130				
Andes 2b	Chile	Solar	207	51 %	2023-2024		Various
		Energy Storage	129				
Mesa La Paz (1)	Mexico	Wind	306	50 %	2019	2045	Fuentes de Energia Peñoles
McFarland A (OpCo D) (3)	US-AZ	Solar	200	75 %	2023	2038	BP
		Energy Storage	100				
OpCo B (1)	US-Various	Solar	297	26 %	2019	2039-2044	Various
Bolero	Chile	Solar	146	51 %	2023-2025	2038-2042	Various
		Energy Storage	146	89 %			
Bayano	Panama	Hydro	260	49 %	1999	2030	ENSA, Edemet, Edechi, Other
Morris (OpCo D) (3)	US-MO	Solar	250	75 %	2025	2040	Microsoft
Cordillera Hydro Complex (4)	Chile	Hydro	240	99 %	2000	2042	Various
Baldy Mesa (OpCo D) (3)	US-CA	Solar	150	75 %	2023	2043	Amazon
		Energy Storage	75				
Changuinola	Panama	Hydro	223	90 %	2011	2030	AES Panama

Great Cove 1&2 (OpCo D) [3]	US-PA	Solar	220	75 %	2023	2043	University of Pennsylvania
Raceway 1 [1]	US-CA	Solar	125	50 %	2023	2043	Microsoft
		Energy Storage	80				
Prevailing Winds (OpCo B) [1]	US-SD	Wind	200	26 %	2020	2050	Basin Electric Power Cooperative
Oak Ridge (OpCo D) [3]	US-LA	Solar	200	75 %	2023	2043	Amazon
OpCo D	US-Various	Solar	177	75 %	2022-2025	2042-2045	Various
		Energy Storage	22				
Delta (OpCo D) [3]	US-MS	Wind	185	75 %	2023-2024	2043-2044	Amazon
McFarland C (OpCo D) [3]	US-CA	Energy Storage	185	75 %	2025	2045	Southern California Edison
Skipjack (OpCo D) [3]	US-VA	Solar	175	75 %	2022	2036	Constellation Energy Generation
Andes Solar 2a	Chile	Solar	81	51 %	2021-2024	2038	Google, Various
		Energy Storage	80				
St. Nikola	Bulgaria	Wind	156	89 %	2010	2026	KER Toki
Cavalier (OpCo D) [3]	US-VA	Solar	156	75 %	2023-2024	2043	Dominion Energy
Atacama Solar	Chile	Solar	150	99 %	2024	2035	Collahuasi
Peravia I&II [1]	Dominican Republic	Solar	140	33 %	2025	2036-2040	Andres, Ede Sur
Lancaster Area Battery (LAB) (OpCo D) [3]	US-CA	Energy Storage	127	75 %	2022	2037	PG&E
Calhoun (OpCo D) [3]	US-MI	Solar	125	75 %	2024	2039	Microsoft, MPPA
Chiriqui-Esti	Panama	Hydro	120	49 %	2003	2030	ENSA, Edemet, Edechi, Other
Kuihelani (OpCo E) [3]	US-HI	Solar	60	100 %	2023-2024	2048	HECO
		Energy Storage	60				
Los Olmos	Chile	Wind	110	51 %	2022	2032	Google, Various
Los Cururos	Chile	Wind	109	51 %	2019		Various
Cabra Corral	Argentina	Hydro	102	100 %	1995		Various
Southland Energy—Alamitos Energy Center	US-CA	Energy Storage	100	50 %	2021	2041	Southern California Edison
East Line Solar (OpCo B) [1]	US-AZ	Solar	100	26 %	2020	2045	Salt River Project Agricultural Improvement & Power District
Central Line (OpCo B) [1]	US-AZ	Solar	100	26 %	2022	2039	Salt River Project Agricultural Improvement & Power District
West Line [1]	US-AZ	Solar	100	50 %	2022	2047	Salt River Project Agricultural Improvement & Power District
Luna (OpCo D) [3]	US-CA	Energy Storage	100	75 %	2022	2037	Clean Power Alliance of Southern California
Vientos Bonaerenses	Argentina	Wind	100	100 %	2020	2026-2040	Various
Vientos Neuquinos	Argentina	Wind	100	100 %	2020	2026-2040	Various
Mirasol [1]	Dominican Republic	Solar	100	33 %	2024	2039	Ede Este
Laurel Mountain Repowering (OpCo D) [3]	US-WV	Wind	99	75 %	2022	2037	AES CE Solutions, LLC
Estrella [1]	US-CA	Solar	56	50 %	2023	2038	Clean Power Alliance of Southern California
		Energy Storage	28				
Cavalier Solar A2 (OpCo D) [3]	US-VA	Solar	84	75 %	2024	2044	Microsoft
Alamitos 2 (OpCo E) [3]	US-CA	Energy Storage	82	100 %	2024	2044	Southern California Edison
San Matias	Chile	Wind	82	51 %	2023-2025	2038	Microsoft
Platteview (OpCo D) [3]	US-NE	Solar	81	75 %	2023	2043	Omaha Public Power District
Clover Creek (OpCo B) [1]	US-UT	Solar	80	26 %	2021	2046	UMPA

Westwing 1 (OpCo E) (3)	US-AZ	Energy Storage	80	100 %	2023-2024	2043-2044	APS
Silver Peak (OpCo D) (3)	US-CA	Solar	50	75 %	2024	2044	Amazon
		Energy Storage	25				
Mesamávida	Chile	Wind	68	51 %	2022-2023	2038	Google, Various
Mountain View Repowering (OpCo D) (3)	US-CA	Wind	67	75 %	2022	2042	Central Coast Community Energy, Silicon Valley Clean Energy Authority
Campo Lindo	Chile	Wind	66	51 %	2023		Various
Madison (OpCo D) (3)	US-VA	Solar	63	75 %	2024	2039	Northrop Grumman
Westwing 2A (OpCo D) (3)	US-AZ	Energy Storage	62	75 %	2024	2044	APS
San Fernando	Colombia	Solar	61	99 %	2021	2036	Ecopetrol
Big Island Waikoloa (OpCo E) (3)	US-HI	Solar	30	100 %	2022-2023	2047	HECO
		Energy Storage	30				
Waiawa Phase 2	US-HI	Solar	30	75 %	2025	2045	HECO
		Energy Storage	30				
Westwing 2B (OpCo D) (3)	US-AZ	Energy Storage	59	75 %	2024	2044	APS
Keydet North	US-VA	Solar	58	75 %	2025	2045	Microsoft
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 (1)	Dominican Republic	Solar	50	33 %	2021	2036	Ede Sur
Agua Clara (1)	Dominican Republic	Wind	50	33 %	2022	2039	Ede Norte
Santanasol (1)	Dominican Republic	Solar	50	33 %	2022	2038	Ede Sur
Virtual Reservoir 2	Chile	Energy Storage	50	99 %	2023		
Mountain View IV (OpCo E) (3)	US-CA	Wind	49	100 %	2012	2032	Southern California Edison
Chiriqui-La Estrella	Panama	Hydro	48	49 %	1999	2030	ENSA, Edemet, Edechi, Other
AM Solar	Jordan	Solar	48	36 %	2019	2039	National Electric Power Company
Ullum	Argentina	Hydro	45	100 %	1996		Various
Lawa'i (3)	US-HI	Solar	20	100 %	2018	2043	Kaua'i Island Utility Cooperative
		Energy Storage	20				
Kekaha (3)	US-HI	Solar	14	100 %	2019	2045	Kaua'i Island Utility Cooperative
		Energy Storage	14				
Brisas	Colombia	Solar	27	99 %	2022	2037	Ecopetrol
West Oahu Solar (OpCo E) (3)	US-HI	Solar	12.5	100 %	2023	2048	HECO
		Energy Storage	12.5				
Na Pua Makani (OpCo E) (3)	US-HI	Wind	24	100 %	2020	2040	HECO
Ilumina	US-PR	Solar	24	100 %	2012	2037	PREPA
Andes Solar 1	Chile	Solar	22	99 %	2016	2036	Quebrada Blanca
Castilla	Colombia	Solar	21	99 %	2019	2034	Ecopetrol
Tunjita	Colombia	Hydro	20	99 %	2016	2026-2039	Various
Cochrane ES (5)	Chile	Energy Storage	20	97 %	2016		
Angamos ES	Chile	Energy Storage	20	99 %	2011		
Esti Solar II	Panama	Solar	18	49 %	2025	2030	ENSA, Edemet, Edechi, Other
Laurel Mountain ES (OpCo E) (3)	US-WV	Energy Storage	16	100 %	2011		

Community Energy	US-Various	Solar	14	75 %	2022	2030-2039	Various
Andes [(6)]	Chile	Energy Storage	12	99 %	2009		
Southland Energy—AES Gilbert (Salt River) [(7)]	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		
Alfalfal Virtual Reservoir	Chile	Energy Storage	10	99 %	2020		
Corotú	Panama	Solar	10	49 %	2025	2030	ENSA, Edemet, Edechi, Other
Los Santos	Panama	Solar	8	49 %	2025	2030	ENSA, Edemet, Edechi, Other
OpCo C [(1)]	US-Various	Solar	6	50 %	2021-2022	2041-2042	Various
Warrior Run ES	US-MD	Energy Storage	5	100 %	2016		
5B Colon	Panama	Solar	1	100 %	2021	2051	Costa Norte LNG Terminal
PFV Kaufmann	Chile	Solar	1	99 %	2021	2040	Kaufmann
			17,836				

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

(2) Operated by AES under a concession contract granted for a term of 30 years. On January 9, 2026, upon expiration of the contract, ownership and possession of the power plant equipment was transferred by full right to a new operator, awarded with the new concession contract through an international bidding process carried out by the Argentine State in its capacity as grantor.

(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, which 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* on the Consolidated Balance Sheets, depending on the partnership rights of the specific project.

(4) The Cordillera Hydro Complex includes the Alfalfal, Queltehues, and Volcan hydroelectric plants.

(5) AES Andes acquired the remaining preferred shares in Cochrane ES in February 2026, increasing AES' equity interest in the plant to 100%.

(6) In January 2026, AES Andes sent a letter to the ISO requesting permanent disconnection as of April 30, 2026.

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

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
Keydet	US-VA	Solar	62	75 %	1H 2026
West Camp	US-AZ	Wind	80	75 %	1H 2026
Halifax	US-NC	Solar	80	75 %	1H 2026
Jobos	US-PR	Solar	80	70 %	1H 2026
		Energy Storage	110		
Salinas	US-PR	Solar	120	70 %	1H 2026
		Energy Storage	175		
Arenales	Chile	Energy Storage	300	100 %	1H 2026
Armadillo	US-TX	Solar	200	75 %	1H 2026
AES Clean Energy Development	US-Various	Solar	12	75 %	1H-2H 2026
Bellefield 2	US-CA	Solar	500	75 %	2H 2026
		Energy Storage	500		
Windsor	US-VA	Solar	85	75 %	2H 2026
Baldy Mesa Energy Storage	US-CA	Energy Storage	50	75 %	1H 2027
Vientos Bonaerenses 3 and 4	Argentina	Wind	102	100 %	1H 2027
Buffalo Gap Repowering	US-TX	Wind	527	100 %	1H 2027
Cristales	Chile	Solar	287	100 %	1H 2027
		Energy Storage	340		
Pampas	Chile	Solar	229	100 %	1H 2027
		Energy Storage	340		
		Wind	128		
Atacama	Chile	Energy Storage	250	100 %	1H 2027
Four Horizons	US-TX	Wind	945	75 %	2H 2027 - 1H 2028
			5,502		

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 46 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' time to power, while delivering green attributes. The generation capacity of the systems owned and/or operated under AES Clean Energy is 10,961 MW across the U.S., with another 3,031 MW under construction, including 1,542 MW of wind, 939 MW of solar, and 550 MW of energy storage. AES Clean Energy has a 7.6 GW backlog of projects, the majority of which are expected to come online through 2029. 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, AES Clean Energy Development, and other renewables assets as part of its broader investments in the U.S. AES Clean Energy Development serves as the development vehicle for all future renewables projects in the U.S. AES Clean Energy Development is a leader in the U.S. renewables industry, and, in 2025, it added over 2.1 GW of high-quality projects to its backlog.

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 (including long-term REC contracts), 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 Inflation Reduction Act ("IRA"). In 2025, AES recognized $1.5 billion related to the monetization of tax attributes to tax equity investors and transferability tax credit buyers relating to U.S. renewables projects, $166 million of which relates to solar projects owned by our utility at AES Indiana. The financial results of U.S. renewables assets are primarily driven by the amount of wind or solar resource at the facilities, availability of facilities, growth in projects, the profitable development and sale of energy, RECs, and other generation attributes to customers, and by tax credit recognition once placed in service.

The majority of solar projects under AES Clean Energy 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, which 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 2025, AES Clean Energy largely generated investment tax credits ("ITCs") from its renewable assets. ITCs and production tax credits ("PTCs"), as well as higher credits available for projects that satisfy wage and apprenticeship requirements under the IRA, increased demand for our renewables products in recent years. Also, in 2023, AES Clean Energy began monetizing tax credits under the transferability provisions of the IRA. These tax credit sales reduce our tax rate under U.S. GAAP.

AES Clean Energy's contracted and advanced stage development backlog is resilient to recent changes in the IRA. Recent guidance revising start of construction safe harbor thresholds is not expected to affect a substantial majority of AES Clean Energy projects already safe harbored, and, taking into account current project schedules, we do not currently expect any material impact to our backlog.

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. For corporate customers, this includes advanced 24/7 carbon-free energy offerings tailored to support large energy-intensive operations, such as hyperscale data centers, by combining renewables, storage, and load-siting solutions. Concurrently, AES develops and delivers ready-to-build renewable energy projects and powered land for regulated utilities and corporate customers through Develop-Transfer Agreements, in which AES manages the full greenfield development process (including permitting, engineering, and procurement) and transfers the project once it reaches construction-ready status. AES has worked with several major technology companies to provide clean energy solutions to power their networks of data centers, and we expect these relationships to expand as the rapid adoption of generative artificial intelligence drives significant growth in data center electricity demand.

In 2025, AES Clean Energy signed or was awarded 2,776 MW of PPAs. As of December 31, 2025, AES Clean Energy's renewables project backlog includes 7.6 GW of projects for which long-term PPAs have been signed or, as applicable, contracts have been assigned through a regulatory process. The budget for construction of the projects currently under construction and the contracted projects is over $12 billion. U.S. federal legislation includes tax credits for onshore wind, solar, and storage. These tax credits are supportive of our strategy to grow the AES Clean Energy business through the development of our 46 GW U.S. pipeline.

AES Chile

Business Description — AES Chile is engaged in the generation and supply of electricity (energy and capacity) in the SEN—see *Energy Markets and Regulatory Environment* below— through AES Andes, AES Pacifico Chile, and their subsidiaries. In total, AES operates 2,195 MW of renewable installed capacity in Chile, excluding energy storage, and has a market share of approximately 6% as of December 31, 2025. In addition, AES Chile has 768 MW of energy storage systems in operation.

AES Andes' Green Blend strategy aims to reduce carbon intensity and to incorporate renewable energy to extend our previous conventional PPAs by de-linking our PPAs from legacy fossil resources while growing our renewable energy portfolio. This strategy delivers a competitive and reliable energy solution for customers, AES Chile has committed 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 14 years with unregulated customers, such as mining and industrial companies, mainly with pricing indexed to CPI.

Key Financial Drivers — Hedging strategies at AES Chile 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 hydrological scenarios, forced outages, and international fuel prices);
- changes in current regulatory rulings, tax policies; and
- fluctuations of the Chilean peso.

Development Strategy — In Chile, AES is building wind, solar, and storage to supply AES Andes' agreements with its main mining customers. In total, the pipeline in Chile currently includes 5.5 GW under development at different stages and geographical locations.

AES Argentina

Business Description — In Argentina, AES owns and operates two fully contracted wind power plants totaling 200 MW and operates 157 MW of hydroelectric power plants. In addition, AES Argentina previously operated the 1,050 MW Alicura hydroelectric plant under a concession contract which ended on January 9, 2026. The total 1,407 MW represents 3% of the country's total installed capacity. 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 2025, approximately 70% of the energy sold was produced by the hydroelectric power plants and sold in the wholesale electricity market and the remaining 30% was 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;
- changes in hydrology and wind resources; and
- domestic energy demand and exports.

Development Strategy — In 2025, a subsidiary of AES Argentina began construction on the Vientos Bonaerenses 3 and 4 projects, two wind facilities totaling 102 MW. This new capacity is intended to be used 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 Castilla, Brisas, and San Fernando solar facilities with capacity of 21 MW, 26 MW, and 61 MW, respectively. AES Colombia's installed capacity accounted for approximately 5% of system capacity at the end of 2025. 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, and in 2025, all relevant permits for 259 MW were obtained. In 2025, AES Colombia executed an investment agreement for a partnership structure with Ecopetrol S.A. in connection with these projects. Under the terms of the partnership, the projects will be contributed to two trusts, which will own, construct, operate, and maintain the projects and sell the energy generated to Ecopetrol under a PPA.

AES Panama

Business Description — AES owns and operates five hydroelectric plants totaling 705 MW of generation capacity, a wind farm of 55 MW, and eight solar plants totaling 77 MW, which collectively represent 16% 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 regulating 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 renewables assets in the system and contribute to the reduction of hydrological risk in Panama.

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. In addition, in 2024, AES began construction on 485 MW of new renewables projects. 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 — Development in Puerto Rico is primarily through the Marahu Project, which is 70% owned by AES and is currently constructing the Salinas and Jobos renewables projects, which include both solar and energy storage facilities.

AES Dominicana

Business Description — AES has a strategic partnership with the Estrella and Linda Groups ("Estrella-Linda"), two leading Dominican industrial groups that manage a diversified business portfolio, and with AFI Popular, a subsidiary of Grupo Popular. AES' ownership interest in AES Dominicana is 65%.

AES Dominicana has partnered with Total Energies Renewable Iberica S.L.U., in AES DR Renewables Holdings, S.L., a joint venture accounted for as an equity method investment, to operate four solar farms totaling 340 MW and a wind farm of 50 MW. AES' effective ownership interest in AES DR Renewables Holdings, S.L. and its subsidiaries is 33%.

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 renewables plants.

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 its power under long-term PPAs with expiration dates 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 is actively working to develop new renewable energy projects that may increase its market share in the Mexican National Energy System, with a strong commitment to provide energy support for the economic growth of the country.

AES Bulgaria

Business Description — AES owns an 89% economic interest in the St. Nikola wind farm ("Kavarna"), which has 156 MW of installed capacity. The power output of St. Nikola is sold to customers operating on the liberalized electricity market. In addition, the plant received additional revenue per the terms of an October 2018 Contract for Premium with the state-owned Electricity System Security Fund until the expiration of the agreement on March 15, 2025.

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.

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.

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 of this business as we have a controlling interest.

Utilities

Business Overview

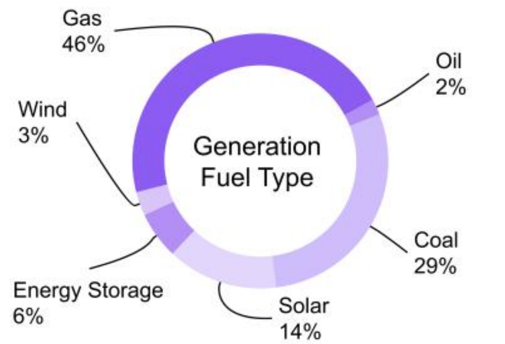
15 Generation Facilities

6 Utility Companies

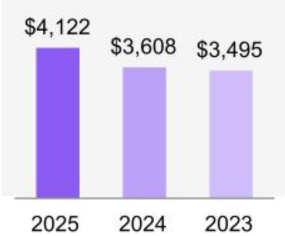
4,199 Gross MW

35,052 GWH

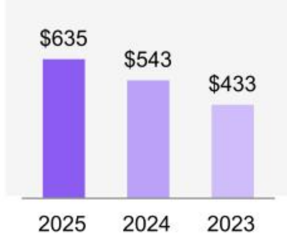
Key Utilities: **AES Indiana, AES Ohio, and AES El Salvador**



Revenue
(In millions)



Operating Margin
(in millions)



Adjusted EBITDA [(1)]
(in millions)

Adjusted PTC [(1)]
(in millions)

Key events in 2025

- Completed the construction of 0.5 GW of renewables at AES Indiana
- AES Indiana reached agreement for 390 MW of new data center load growth within its service territory
- AES Indiana received final regulatory approval for 170 MW Crossvine solar-plus-storage project
- AES Indiana reached a partial settlement for its distribution rate review
- AES Indiana filed a 20-year IRP
- To fund the substantial growth at AES Ohio, closed on the sale of an approximate 30% indirect equity interest to a wholly-owned subsidiary of CDPQ
- AES Ohio reached a unanimous settlement resolving its distribution rate review

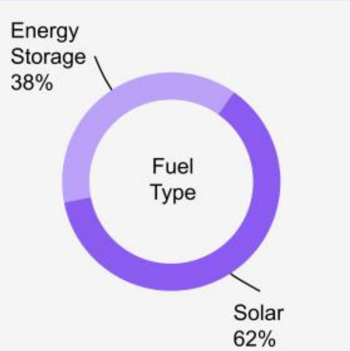
Strategic outlook

- Total backlog of 0.5 GW of renewables
- Construction activities are ongoing to convert remaining two coal units of Petersburg at AES Indiana to natural gas

Under construction

2 Plants

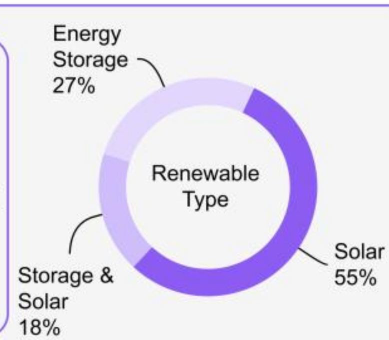
225 MW



Contracted renewable backlog

485 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. at our two utilities: AES Indiana and AES Ohio. The expansion of advanced manufacturing and data centers has the potential to significantly accelerate the demand for electricity in the U.S. power markets. AES Indiana and AES Ohio have an obligation to serve customers who are located in our service territory and are working with several companies to provide solutions for the electric service needs of data centers and advanced manufacturing facilities. We see these relationships growing with the expansion of their use within our service territory. As part of this process, AES Indiana and AES Ohio are working to ensure that the costs of any required infrastructure upgrades benefit all customers, are fairly allocated, and follow regulatory principles that protect our customers.

In the Utilities segment, AES operates four utilities in El Salvador with installed operating capacity of 143 MW, as well as an integrated utility in Indiana, with installed operating capacity of 4,056 MW. IPALCO (the parent of AES Indiana), AES Ohio, and DPL LLC (formerly DPL Inc.) are all SEC registrants and therefore comply with 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 12/31/2025	Approximate GWh Sold in 2025	Fuel	Gross MW	Year Acquired or Began Operation
CAESS	El Salvador	Distribution	75 %	683,000	2,370			2000
CLESA	El Salvador	Distribution	80 %	506,000	1,307			1998
DEUSEM	El Salvador	Distribution	74 %	101,000	197			2000
EEO	El Salvador	Distribution	89 %	377,000	870			2000
El Salvador Subtotal				**1,667,000**	**4,744**			
AES Ohio [(1)]	US-OH	Transmission & Distribution	70 %	541,000	14,729			2011
AES Indiana [(2)]	US-IN	Integrated	70 %	533,000	15,579	Coal/Gas/Oil/Solar/Energy Storage/Wind	4,056	2001
United States Subtotal				**1,074,000**	**30,308**		**4,056**	
				2,741,000	**35,052**			

(1) AES Ohio's GWh sold in 2025 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 2,740 GWh in 2025. 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 nameplate generation capacity of approximately 2,390 MW. AES Ohio’s share of this generation is approximately 117 MW. On April 4, 2025, DPL sold an indirect equity interest in AES Ohio of approximately 30% to a wholly-owned subsidiary of CDPQ.

(2) CDPQ owns direct and indirect interests in IPALCO (AES Indiana's parent) which total approximately 30%. AES owns 85% of AES U.S. Investments and AES U.S. Investments owns 82.35% of IPALCO. AES Indiana plants: Georgetown, Harding Street, Petersburg, Eagle Valley, Hoosier Wind, Hardy Hills Solar, Pike County BESS, and Petersburg Energy Center. 20 MW of AES Indiana total is considered a transmission asset.

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 %	2023	2043-2048	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
Meanguera del Golfo	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
Santa Ana IV	El Salvador	Solar	55	100 %	1H 2026
Crossvine (AES Indiana)	US-IN	Solar	85	70 %	1H 2027
		Energy Storage	85		
			225		

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 982,000 people.

AES Indiana owns and operates four generating stations, all within the state of Indiana. The first station, Petersburg, consists of two coal-fired units; however, AES Indiana is in the process of converting these remaining two coal-fired units to natural gas in 2026 (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. AES Indiana also 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 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 200 MW of wind-generated electricity and 94 MW of solar-generated electricity.

AES Indiana also owns four renewable energy facilities currently in operations, all within the state of Indiana. The first is a 195 MW solar project ("Hardy Hills Solar"). The second is a 106 MW wind facility ("Hoosier Wind"). The third is a 200 MW (800 MWh) battery energy storage project ("Pike County BESS"). The fourth is a 250 MW solar and 45 MW (180 MWh) energy storage facility ("Petersburg Energy Center").

On May 16, 2025, AES Indiana completed the acquisition of Crossvine Solar 1, LLC ("Crossvine"), including the development of 85 MW of solar and 85 MW (340 MWh) of energy storage which is expected to be placed in service in mid-2027.

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 (including a return) to comply with environmental laws and regulations and investments in renewable energy projects, and recovery of costs related to generation consumables and environmental allowance expenses, referred to as the ECCRA, (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 the timely recovery of costs (including a return) incurred 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.

On April 17, 2024, the IURC issued an order (the “2024 Base Rate Order”) approving the Stipulation and Settlement Agreement that AES Indiana entered into on November 22, 2023, with the Indiana Office of Utility Consumer Counselor and the other intervening parties in AES Indiana’s base rate case filing. Among other matters and consistent with the Stipulation and Settlement Agreement, the 2024 Base Rate Order approves an increase in AES Indiana's total annual operating revenue of $71 million for AES Indiana’s electric service and provides a return on common equity of 9.9% and cost of long-term debt of 4.9% on a rate base of approximately $3.5 billion. Updated customer rates and charges became effective on May 9, 2024.

On June 3, 2025, AES Indiana filed a petition with the IURC 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 base rate increase request include inflationary impacts on O&M expenses and continued investments in generation, transmission, and distribution assets. AES Indiana is also seeking recovery of increased costs to support its vegetation management plan, storm restoration costs, and technology to enhance resiliency and reliability. On October 15, 2025, AES Indiana entered into a Stipulation and Settlement Agreement (the "Settlement") with most parties in AES Indiana's pending regulatory rate review at the IURC. This Settlement provides for updated base rates for electric services in AES Indiana's territory and is subject, and conditioned upon, approval by the IURC. Among other things, the Settlement proposes an increase in AES Indiana's revenue of $90.7 million and provides a return on common equity of 9.75% and cost of long-term debt of 5.34%, on a rate base of approximately $5.5 billion for AES Indiana's 2027 electric service base rates. The partial settlement agreement also includes a commitment to not implement additional base rate increases, following the implementation of new base rates under the Settlement, until at least January of 2030 and to not start a second TDSIC Plan before January of 2028. An evidentiary hearing with the IURC was held on January 28 and 29, 2026, and AES Indiana anticipates a final order from the IURC in the second quarter of 2026.

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. The first 80% 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 with the TDSIC rider rate filings by six months as ordered by the IURC and are filed each December.

Integrated Resource Plan — In January 2025, AES Indiana initiated its 2025 Integrated Resource Plan ("IRP") process with external stakeholders. Public advisory meetings for the 2025 IRP took place in January, July, September, and October of 2025. On October 31, 2025, AES Indiana filed its 2025 IRP with the IURC, 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 reliable and flexible generation mix for customers.

AES Indiana filed its 2022 IRP with the IURC in December 2022. The 2022 IRP short-term action plan includes converting the two remaining coal units at Petersburg to natural gas. Resulting from this IRP, AES Indiana also added three renewables projects to its generation portfolio: Pike County BESS, Hoosier Wind, and Crossvine.

On March 11, 2024, AES Indiana filed for regulatory approval from the IURC to convert Petersburg Units 3 and 4 from coal to natural gas and to recover costs through future rates. On November 6, 2024, the IURC issued an order approving the Petersburg repowering. Petersburg Unit 3 was taken offline in February 2026, and Petersburg Unit 4 is expected to be taken offline in June 2026. Construction activities are ongoing, with the units as converted expected to come back online for commissioning by May 2026 and October 2026, respectively.

AES Indiana expects to spend an estimated $4.2 billion on capital projects from 2026 through 2028. This total includes spending on 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. The estimated spending includes projects that are subject to regulatory approval, as well as estimated spending under AES Indiana's 2025 IRP.

AES Ohio

Business Description — DPL is a holding company whose principal indirect subsidiary is AES Ohio. AES Ohio is a utility company that transmits and distributes electricity to approximately 541,000 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 wholesale transmission service, wholesale electric sales, and ancillary services are subject to FERC jurisdiction. AES Ohio uses a formula-based rate for its transmission service.

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.

AES Ohio ESP Appeal — From November 1, 2017 through December 18, 2019, AES Ohio operated pursuant to an approved ESP plan, which was initially approved on October 20, 2017 (ESP 3). On December 18, 2019, the PUCO approved AES Ohio's Notice of Withdrawal of ESP 3 and reversion to its prior rate plan (ESP 1). Among other items, the PUCO Order approving the ESP 1 rate plan included reinstating the non-bypassable RSC Rider, which provided annual revenue of approximately $79.0 million. The OCC has appealed to the Ohio Supreme Court the PUCO's decision approving the reversion to ESP 1 as well as argued for a refund of the RSC revenue dating back to August 2021. Oral arguments regarding this appeal were held on April 22, 2025, and a court decision is pending.

Smart Grid Comprehensive Settlement — On October 23, 2020, AES Ohio entered into a Stipulation and Recommendation (the Settlement) with the staff of the PUCO, various customers and organizations representing customers of AES Ohio and certain other parties with respect to, among other matters, AES Ohio's applications for (i) approval of AES Ohio's plan to modernize its distribution grid (Smart Grid Phase 1), (ii) findings that AES Ohio passed the SEET for 2018 and 2019, and (iii) findings that AES Ohio's ESP 1 satisfies the SEET and the more favorable in the aggregate (MFA) regulatory test. On June 16, 2021, the PUCO issued their opinion and order accepting the stipulation as filed. The OCC appealed the final PUCO order with respect to the 2018 and 2019 SEET to the Ohio Supreme Court on December 6, 2021. Oral arguments regarding this appeal were held on April 2, 2025. The Ohio Supreme Court reversed the PUCO's opinion and order with respect to the methodology used by the PUCO to support its findings related to the 2018 and 2019 SEET, and remanded the case to the PUCO to conduct further analysis of the SEET for those years. AES Ohio filed testimony with the PUCO proposing a refund of $1.6 million based on analysis by its external financial consultant. The PUCO commenced an evidentiary hearing on this issue on October 28, 2025, and a PUCO decision is pending.

Smart Grid Phase 2 Plan — In February 2024, AES Ohio filed a Smart Grid Phase 2 with the PUCO proposing a ten-year investment plan to begin after Smart Grid Phase 1 ends. On September 13, 2024, AES Ohio reached a settlement with the PUCO staff and other parties on the pending Smart Grid Phase 2 application and an evidentiary hearing was held on October 29, 2024. A fundamental premise of the Application was the continued availability of rider recovery of Smart Grid investments through the plan period. However, with the recent enactment of House Bill 15 described above, which prohibits AES Ohio from applying for a new electric security plan which includes certain rider recovery mechanisms, as well as the near-term financial uncertainty created by the statute, AES Ohio withdrew its Smart Grid Phase 2 Application on May 23, 2025. On July 9, 2025, the PUCO approved the withdrawal and closed the case. This withdrawal will provide AES Ohio flexibility as to the timing and scope of Smart Grid investments to continue to deliver benefits to customers.

ESP 4 — 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 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 "ESP 4 Settlement") with respect to AES Ohio's ESP 4 application, and, in August 2023, the PUCO issued their opinion and order accepting the ESP 4 Settlement as filed. AES Ohio is currently operating under this ESP 4 until its expiration, which was extended to May 31, 2027 based on House Bill 15, unless superseded by a Commission-approved Three-Year Rate Plan and MRO.

2024 Distribution Rate Case — On November 29, 2024, AES Ohio filed a distribution rate case with the PUCO. The investments reflected in this distribution rate case include investments to enhance the safety, reliability, and resilience of the distribution system. The application was based on a date certain of September 30, 2024 and a test period of June 1, 2024 - May 31, 2025. On June 27, 2025, the PUCO Staff submitted their Report and Recommendations. On August 13, 2025, AES Ohio entered into an unopposed Stipulation and Recommendation (the "2024 DRC Settlement") with various intervening parties and the Staff of the PUCO and on November 5, 2025, the PUCO issued their opinion and order accepting the 2024 DRC Settlement as filed. The 2024 DRC Settlement provides for updated base rates for electric distribution service customers in AES Ohio's service territory and among other matters includes: (i) An increase to its annual distribution revenue requirement of $167.9 million, which incorporates certain investments that are currently recovered through the Distribution Investment Rider; (ii) a return on equity of 9.999% and a cost of long-term debt of 4.49% on a distribution rate base of $1.25 billion and based on a capital structure of 53.87% equity and 46.13% long-term debt; and (iii) the net recovery of certain expenditures by AES Ohio, primarily related to one-time costs supporting the implementation of AES Ohio's customer billing system upgrade.

Ohio Energy Legislation and Three-Year Rate Plan — On April 30, 2025, the Ohio legislature passed new energy legislation (House Bill 15) that was signed by the Governor and became effective August 14, 2025. The legislation allows Ohio's electric utilities to file three-year forecasted base distribution rate cases, which would replace ESPs and associated recovery riders. AES Ohio currently anticipates that remaining recovery rider balances would be included in future base rates. Among other provisions, the legislation eliminates, as of its effective date, the LGR, which previously allowed for recovery of net OVEC costs and revenues. Changes to the regulatory framework from this legislation, including the recovery of future net OVEC costs and revenues or remaining recovery rider balances, could be material to our results of operations, financial condition, and cash flows.

To comply with House Bill 15, AES Ohio filed an application with the PUCO on November 10, 2025 to establish a Three-Year Rate Plan. This plan describes the investments necessary to strengthen and modernize AES Ohio's infrastructure and expand support for its customers. To enable these ongoing investments, the application also proposes rates for future electric distribution service in 2027, 2028, and 2029. The PUCO has set the evidentiary hearing to begin August 4, 2026, and a Commission Order is anticipated by the end of 2026.

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 $1.6 billion on capital projects from 2026 through 2028, which includes expected spending under AES Ohio's Smart Grid Phase 1 described above, as well as other transmission and distribution additions and improvements. AES Ohio's spending programs are contingent on, among other events, successful regulatory outcome in pending proceedings.

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 4,744 GWh of the market energy sales during 2025. 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, and Meanguera del Golfo, a solar and battery storage facility with 1 MW capacity; as well as AES Nejapa, a biomass power plant with 6 MW capacity; and 50% of Bosforo and Cuscatlan, 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. Electromobility 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 solar farm, 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.

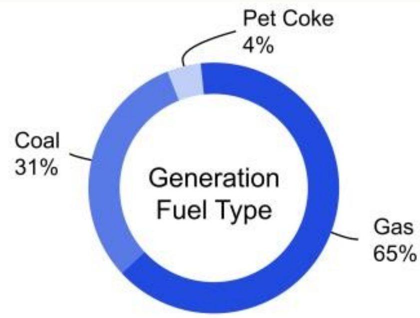
Energy Infrastructure

Business Overview

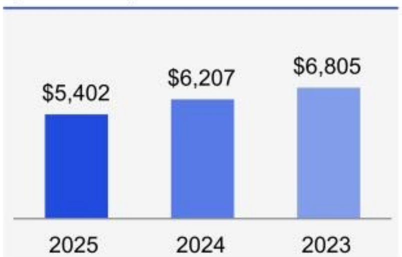
23 Generation Facilities

12,705 Gross MW

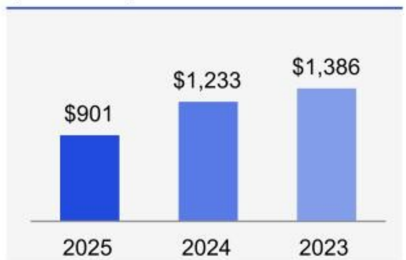
Key Generation Businesses: **Southland, AES Argentina, Mong Duong**



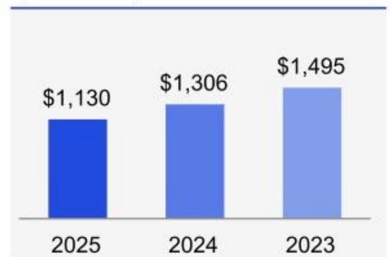
Revenue
(In millions)



Operating Margin
(in millions)



Adjusted EBITDA [1]
(in millions)



Key events in 2025

- Acquired remaining common shares in Cochrane in Chile
- Intend to continue owning and operating Mong Duong 2 in Vietnam

Strategic outlook

- Provide energy security to enable the integration of new renewables and maximize the value of our gas generation and LNG business

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[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.

Energy Infrastructure

Our Energy Infrastructure SBU aims to provide energy security to enable the integration of new renewables and maximize the value of our gas generation and LNG business through flexible operations that support the energy transition. 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.

Generation — Operating installed capacity of our Energy Infrastructure segment totals 12,705 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	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	US-CA	Gas	694	50 %	2020	2040	Southern California Edison
Southland Energy—Alamitos	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)
Gatun [1]	Panama	Gas	670	24 %	2024	2049	ENSA, Edemet, Edechi
TermoAndes [2]	Argentina	Gas/Diesel	643	99 %	2000	2025	Various
Guillermo Brown [3]	Argentina	Gas/Diesel	576	— %	2016		
Angamos	Chile	Coal	558	99 %	2011		Various
Cochrane [4]	Chile	Coal	550	97 %	2016	2030-2037	SQM, Sierra Gorda, Quebrada Blanca
AES Puerto Rico	US-PR	Coal	524	100 %	2002	2027	PREPA
Merida III	Mexico	Gas/Diesel	505	75 %	2000	2026	SIMSA, Regulus, Ammper, Trade On, Atrias
Amman East [1]	Jordan	Gas	472	10 %	2009	2033	National Electric Power Company
Colon [5]	Panama	Gas	381	65 %	2018	2028	ENSA, Edemet, Edechi
DPP (Los Mina)	Dominican Republic	Gas	358	65 %	1996	2027	Ede Este, Ede Norte, Ede Sur, Non-Regulated Users
Andres [6]	Dominican Republic	Gas/Diesel	319	65 %	2003	2027	Ede Este, Ede Norte, Ede Sur, Non-Regulated Users
Termoeléctrica del Golfo (TEG)	Mexico	Pet Coke	275	99 %	2007	2027	CEMEX
Termoeléctrica del Penoles (TEP)	Mexico	Pet Coke	275	99 %	2007	2027	Peñoles
IPP4 [1]	Jordan	Gas	250	10 %	2014	2039	National Electric Power Company
Southland—Huntington Beach	US-CA	Gas	236	100 %	1998	2026	California Department of Water Resources
Sarmiento	Argentina	Gas/Diesel	33	100 %	1996		
			12,705				

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

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

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

(4) AES Andes acquired the remaining preferred shares in Cochrane in February 2026, increasing AES' equity interest in the plant to 100%.

(5) 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.

(6) 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. Enadom is an unconsolidated entity, accounted for as an equity affiliate.

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") and Puerto Rico. AES Southland, operating in the CAISO, is our most significant generation business. In 2023, the Company closed on an agreement to terminate the PPA for the Warrior Run coal-fired power plant, which continued providing capacity through May 2024 before ending commercial operations.

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 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.

Our non-qualifying facility ("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 2,823 MW at the end of 2025. The four 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 two once-through cooling ("OTC") power plants and two combined cycle gas-fired generation facilities. This critical infrastructure is uniquely situated to support California in its transition to renewables with baseload gas-fired generation sited at high-demand points of interconnection within the Los Angeles Basin.

Southland — Southland comprises AES Huntington Beach, LLC and AES Alamitos, LLC ("Southland OTC units"). Commencing on January 1, 2024, the Southland OTC units 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 Resource Adequacy Purchase Agreements (“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 9% 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 2025, approximately 86% of the energy was sold in the wholesale electricity market and 14% was sold under contract by the 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 *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. Given that the sale did not close by the deadline specified in the agreement, AES exercised its right to terminate the agreement and remains the owner of its entire 51% interest.

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 a joint venture agreement with PetroVietnam Gas, and in April 2022, established Son My LNG Terminal LLC, in which AES has a 39% interest. 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 Chile

Business Description — In Chile, AES owns and operates Cochrane and Angamos, two coal-fired power plants with a total combined installed capacity of 1,108 MW, representing a market share of approximately 3% as of December 31, 2025.

Cochrane currently has long-term contracts with an average remaining term of approximately 10 years with mining customers, mainly with pricing indexed to CPI.

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

- spot market prices (largely impacted by dry hydrological 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 — 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, disposal, or shutdown of the following coal-fired plants:

- Ventanas 1 and Ventanas 2 coal-fired units were disconnected from the SEN as of June 30, 2022 and December 31, 2023, respectively.
- Norgener 1 and Norgener 2, with an installed capacity of 276 MW, were disconnected from the SEN on April 15, 2024.
- Ventanas 3 and Ventanas 4, with an installed capacity of 537 MW, were sold on January 13, 2025.
- The Angamos units have an installed capacity of 558 MW and have publicly announced phase-out plans, once the safety, sufficiency, and competitiveness of the system allows it, which has not yet occurred.

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 have successfully migrated from the legacy market to the new energy regime established by the Electric Industry Law of 2021 and both are operating according to ISO instructions.

Merida is a CCGT located on Mexico's Yucatan Peninsula that sold power to CFE under a PPA until December 8, 2025, when the plant successfully migrated to the Wholesale Electricity Market ("WHEM") under the new Electricity Sector Law ("LESE"). The LESE permit allows Merida to sell power in the WHEM for one year, until December 8, 2026, and to trade energy and capacity contracts with third parties, while securing natural gas and diesel under flexible contracts to ensure reliable and continuous operation. The permit term is subject to negotiations with authorities for a possible extension.

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 *Energy Markets and Regulatory Environment* below) in TEG and TEP under self-supply scheme; and
- improved operational performance and plant availability.

AES Panama

Business Description — In Panama, AES owns and operates Colon, a 381 MW combined cycle power plant fueled by natural gas. In partnership with InterEnergy, AES also entered into a joint venture to build and operate the Gatun facility, a 670 MW combined cycle gas power plant. The Gatun plant began commercial operations in open cycle mode in October 2024 and commenced combined cycle operations in May 2025. Furthermore, AES owns and operates an LNG regasification facility, a 180,000 cubic meter net storage tank, and a truck loading facility.

Colon 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 us 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 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 679 MW of installed thermal capacity, AES provides 9% of the country's capacity and supplies approximately 16% of the country's energy demand via these generation facilities. 575 MW are contracted with government-owned distribution companies.

AES has a strategic partnership with the Estrella and Linda Groups ("Estrella-Linda"), two leading Dominican industrial groups that manage a diversified business portfolio, and also with AFI Popular, a subsidiary of Grupo Popular. AES' ownership interest in AES Dominicana is 65%.

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 Dominicana has a 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 and an LNG facility of 120,000 cubic meters, including additional storage, regasification, and truck loading capacity.

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 Jordan

Business Description — In Jordan, AES has a 10% ownership 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 10% ownership interest in the IPP4 plant, a 250 MW oil/gas-fired peaker plant fully contracted with the national utility until 2039. Following the sale of approximately 26% ownership interest in both plants in March 2024, Amman East and IPP4 were deconsolidated and are accounted for as equity method investments.

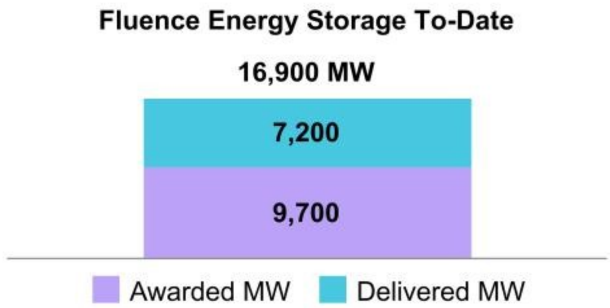
New Energy Technologies

Investing in innovative technologies

Key investments:

FLUENCE
A Siemens and AES Company

maximo



Key events in 2025

- Made equity investments in two companies co-built through a partnership with AI Fund and began initial testing and deployment of their first commercial products
- Maximo advanced from early deployment to established commercial execution, scaling multi robot fleet operations across active utility scale projects, installing over 130,000 solar modules
- Fluence continued to increase its U.S. production footprint by ramping up its Arizona enclosure facility along with securing a second domestic battery cell supplier, reducing regulatory and supply risk

Strategic outlook

- Expect to deploy the products of the companies co-built with AI Fund at scale across several of AES' operating businesses in the U.S. and the Americas, in addition to incubating additional companies with AI Fund
- Maximo will deploy its next generation robot and continue to build its fleet expansion, establishing the foundation to deliver 1 GW of utility solar scale annually
- Fluence continues to see demand accelerate for larger scale projects while its SmartStack product continues to gain traction with deployments in Europe and Asia

New Energy Technologies

Our New Energy Technologies SBU encompasses AES' efforts to incubate innovative solutions and invest in businesses that leverage cutting-edge technology to provide greener and smarter energy solutions, accelerating the energy transition. These activities enhance AES' competitive advantages in its businesses while enabling the growth of new business platforms. This segment includes ownership stakes in third-party platforms and internally developed initiatives, such as investments in Fluence, Maximo, the AI Fund, Uplight, and 5B.

Fluence, the AI Fund, 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. AES has a 100% ownership interest in Maximo, a consolidated entity.

In 2025, AES furthered its partnership with the AI Fund to combine its power sector expertise with the fund's artificial intelligence capabilities, leveraging generative AI technology to address bottlenecks in the energy transition. At the same time, AES made significant advancements with Maximo, an AI-powered robot designed to enhance the speed, efficiency, and safety of solar installations.

Fluence

Business Description — Fluence, created in 2018 as a joint venture by AES and Siemens AG, is a leading global provider of energy storage and services and AI-enabled digital applications for renewables and storage.

On November 1, 2021, Fluence Energy, Inc. completed its IPO and is listed on Nasdaq under the symbol "FLNC". AES holds Class B-1 common stock, granting five votes per share held, and continues to hold its economic interest in the operating subsidiary of Fluence Energy, Inc. As of December 31, 2025, AES holds a 28.19% economic interest in Fluence and the Company accounts 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 undergoing rapid expansion. 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. The global utility scale market, excluding China, will add approximately 3,201 GWh of energy storage capacity between 2024 and 2035, according to the Bloomberg NEF 2H 2025 Energy Storage Market Outlook, published in October 2025. Additional growth opportunities exist in providing 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 7.2 GW of energy storage assets deployed and 9.7 GW of contracted backlog, with a gross global pipeline of 41.8 GW as of December 31, 2025.

Maximo

Business Description — Maximo is an AI-enabled robot that enhances solar module installation speed, efficiency, and safety. Maximo enhances the safety and scalability of solar installation by automating the heavy lifting for placing and attaching solar modules. It accelerates project timelines and creates new high-tech jobs on solar construction sites. As of December 31, 2025, AES had a fleet of five Maximo units in operation that assisted with construction at the 2 GW Bellefield solar-plus-storage facility in California. The Company expects to expand its fleet to serve a growing backlog of installation contracts in 2026.

Key Financial Drivers — Maximo's financial results are driven by the growth in its module installation service revenue, an efficient cost structure that is expected to benefit from increased robotic automation of field operations, and profit margins on customer contracts with solar EPC companies.

Development Strategy — Maximo serves the growing demand for grid scale solar project construction from AES and other leading owners by enabling the EPC companies to deliver projects faster and more efficiently. The Maximo team leverages AES' knowledge and relationships with EPCs, proprietary AI and robotics expertise, and field operations capabilities to offer a compelling solution for solar module installation at grid scale utility projects.

AI Fund

Business Description — In 2024, AES formed a partnership with the AI Fund, an AI-focused venture studio, to co-develop AI-based businesses. In 2025, AES made its first equity investments in two co-built companies.

Key Financial Drivers — Each of the companies co-built by AES and the AI Fund follows a software-as-a-service business model. These companies' financial results are driven by the rate of growth of new customers and the extension of additional services to existing customers.

Development Strategy — AES' collaboration with the AI Fund is designed to create new businesses that support AES' core business operations. In 2025, two co-built companies developed commercial products, and AES was the first company to test and use the first versions of these products.

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 Coordinador Electrico Nacional ("CEN"). The SEN has an installed capacity of 34,931 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, solar capacity represents the majority of installed capacity. The fuels used for thermoelectric generation, mainly coal, diesel, and LNG, are indexed to international prices. In 2025, the installed capacity in the Chilean market was composed of thermoelectric (36%), solar (30%), hydroelectric (21%) and wind (13%) generation.

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 0.3 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.

In addition to energy payments, generators also receive capacity payments to compensate for availability during periods of peak demand. 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.

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-term 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 7,480 MW of installed capacity, composed of thermal (64%), solar (21%), hydroelectric (8%), and wind (7%) generation.

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 originally applicable from 2023 until 2027.

AES El Salvador distribution rates are regulated by the General Superintendence of Electricity and Telecommunications and are established through a traditional cost-based rate-setting process. AES El Salvador is permitted to recover its costs of providing distribution services 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 2,563 MW of installed capacity, composed of thermal (53%), hydroelectric (24%), biomass (11%), solar (10%), and wind (2%) generation.

Bulgaria

The electricity sector in Bulgaria is regulated by the Bulgarian Energy Act. The Bulgarian electricity market allows both regulated and competitive segments. NEK ceased to be the public provider of electricity at the end of June 2025. From July 2025 onwards, Bulgarian distribution companies serving the regulated market are sourcing their electricity needs exclusively from a special segment of the market where NEK is the main supplier through their energy mix (consisting of NEK-owned HPPs, NPP Kozlodui, state owned TPP Maritza East 2, and AES Maritza). 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 17 GW of installed capacity enabling the country to meet and exceed domestic demand and export energy. Installed capacity is primarily composed of solar (34%), thermal (31%), hydro (19%), and nuclear (12%) generation.

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 5,077 MW, composed of thermal (43%), hydroelectric (36%), solar (14%), and wind (7%) generation.

Mexico

Mexico's main electrical system is called the National Interconnected System, 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. 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.

Mexico’s new Electricity Sector Law (LSE) and its Regulations (RLSE), enacted in 2025, replaced the previous framework to centralize control under the state-owned CFE. The reform reinforces the State’s leading role in the electricity industry, preserving transmission and distribution as exclusive state services, while redefining the conditions for private participation in generation and commercialization. The new regulations establish sector planning guidelines, introduce rules for private investment, and implement binding planning mechanisms that condition the approval and development of new projects.

In addition to the Ministry of Energy, three main agencies are responsible for regulating market agents and their activities, monitoring compliance with laws and regulations, and 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 of 92 GW, composed of thermal (64%), hydroelectric (14%), solar (8%), wind (8%), and other fuel (6%) generation.

Argentina

Argentina has one main power system, the SADI, which serves 92% of the country. As of December 31, 2025, the installed capacity of the SADI totaled 44,177 MW. The SADI's installed capacity is composed of thermoelectric (57%), hydroelectric (23%), wind (10%), nuclear (4%), and solar (6%) generation.

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.

The Argentine electricity market operated under a tolling scheme up to and including October 2025. In this structure, the regulator established both electricity prices and reference fuel prices. For energy sold to the spot market, generators received compensation for fixed costs and non-fuel variable costs, typically denominated in Argentine pesos. CAMMESA was in charge of providing the natural gas and liquid fuels required by the generation companies, except for coal. Energy sold through specific PPAs, such as Energía PLUS by TermoAndes, required generators to procure their necessary fuel at a reference price established by the regulator.

The regulatory landscape underwent a significant transformation with SE Resolution 400/25, effective November 2025, which instituted new rules for the wholesale energy market and its progressive adaptation. The new remuneration framework requires generators to manage their fuel supply and declare their variable production cost based on established reference values, while allowing the contracting of energy and/or capacity based on bilaterally negotiated terms. This transition also involved defining prices for demand and the implementation of marginal cost signals for energy traded in the spot market.

During 2025, despite the tariff increase to the end-user implemented by the government, subsidies remain a necessary component to cover the system's operating deficit. While the proportion of the total cost recovered by distribution companies increased to 70%, these funds are still essential for the system's sustainability.

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 the commercial operations date of the related plant. 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, not to exceed 30%, once the accounts receivable have been fully repaid.

In 2024 and 2025, the Argentine peso devalued against the USD by approximately 22% and 29%, 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 and provides electricity to 99% of the country's population. As of December 31, 2025, the SIN's installed capacity was 21,040 MW, composed of hydroelectric (63%), thermal (30%), and other renewables (7%) generation. The marked seasonal variations in Colombia's hydrology result in price volatility in the short-term market. In 2025, 81% 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.

In addition to the reliability charge, the Colombian electricity sector has an additional reliability mechanism known as the risk of shortage statute, established by CREG resolution 026 of 2014. This mechanism is triggered under specific critical hydrological conditions, during which certain reservoirs are utilized to conserve water, thereby increasing thermal dispatch. It was first triggered during late September 2024 until late November 2024.

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 82 GW. The fuel mix in Vietnam is composed primarily of coal (32%), hydroelectric (29%) and renewables generation, including solar, wind, and biomass (26%). EVN, the national utility, owns 38% of installed generation capacity.

Vietnam is implementing a multi-step process to create a competitive electricity market. The first step taken in 2012 was to separate the generation segment of EVN into different joint-stock companies and to create a Competitive Power Market which was effective until 2019. In this market, all generation companies bid into the market and sell to a single buyer which is also owned by EVN. The next step taken in 2019 was to replace the Competitive Power Market with the Electricity Wholesale Market, in which there are several buyers, called EVN Power Corporations, all of which are subsidiaries of EVN. The final step, which is yet to be implemented, is the creation of the Electricity Retail Market, in which non-EVN-owned buyers would be allowed, and direct sales and purchases between retailers and generators would be feasible. The Mong Duong 2 power plant is a BOT plant and does not directly participate in the electricity market. The offtaker bids Mong Duong 2’s tariff into the market on its behalf.

At the end of November 2024, a new electricity law was passed by the National Assembly. The new law provides for a comprehensive reform of the legal framework in the power and energy sector of Vietnam after two decades under the current electricity law of 2004. It provides an improved legal environment for the energy sector, including but not limited to imported LNG power, green hydrogen and ammonia, offshore wind, nuclear power, low-emission conversion, emergency power projects, minimum long-term contracted electricity output, DPPA, and a fuel cost pass-through mechanism.

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 renewables portfolio standard.

Puerto Rico's electricity is 95% produced by thermal plants (50% from petroleum, 37% from natural gas, and 8% from coal), while the remaining 5% is supplied by renewable sources (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.

U.S. Utilities

See Item 1.—*Business—Segments—Utilities* for further discussion of the energy markets and regulatory environment of our utilities in the U.S. — AES Indiana and AES Ohio.

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), species and habitat protections, 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 has often 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, numerous environmental laws and regulations regulate emissions of SO_2, NO_X, particulate matter, GHGs, mercury, hazardous air pollutants, water discharges, waste management, and species and habitat protections. 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 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.

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 and includes enhancements to the revised Group 3 trading program. On June 27, 2024, the U.S. Supreme Court issued an order granting a stay of the EPA's 2023 FIP pending resolution of legal challenges to the FIP.

On November 6, 2024, the EPA published an Interim Final Rule in the Federal Register in response to the U.S. Supreme Court's stay of its FIP addressing interstate transport for the 2015 ozone national ambient air quality standards. The Interim Final Rule stays the effectiveness of the Good Neighbor FIP and revises the CSAPR regulations to continue application of the states' respective trading programs. 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.

New Source Performance Standards for Stationary Combustion Turbines — On December 13, 2024, the EPA published a proposed rule that would revise the NSPS regulating NO_X and SO_2 from certain new, modified, and reconstructed stationary combustion turbines ("CTs"). On January 15, 2026, the EPA issued a final rule establishing more stringent NO_X emissions standards for certain CTs while retaining the existing SO_2 standards. The final rule establishes NO_X emissions limits based on selective catalytic reduction ("SCR") for new, large, high utilization combustion turbines. NO_X emissions limits for other new, modified, and reconstructed CTs are based on combustion controls without SCR. The revised standards apply to affected sources that begin construction, modification, or reconstruction after December 13, 2024. We cannot predict the possible outcome or potential impacts of this matter at this time.

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. On October 2, 2025, the EPA published an advanced notice of proposed rulemaking requesting public input on potential future changes to the Regional Haze Rule. On January 6, 2026, the EPA published a final rule extending the deadline for states to submit implementation plans for the third planning period from July 31, 2028 to July 31, 2031. To date, none of the states in which we operate have submitted plans that identify 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 criteria 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.

On May 7, 2024, the EPA published a final rule to revise MATS for coal and oil-fired electric generating units ("EGUs") which lowers certain emissions limits and revises certain other aspects of MATS. The May 2024 MATS revision rule is subject to legal challenges. On June 17, 2025, the EPA published a proposed rule to repeal the majority of the May 7, 2024 final rule revising MATS. On February 20, 2026, the EPA released a pre-publication version of a final rule repealing the majority of the May 7, 2024 MATS revision rule. We are still reviewing the final rule, and it is too early to determine the potential impacts.

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 — On May 9, 2024, the EPA published the final NSPS requiring carbon capture and sequestration for new and reconstructed baseload stationary combustion turbines, among other requirements. The EPA did not finalize revisions to the NSPS for newly constructed or reconstructed coal-fired electric utility steam generating units as proposed in 2018.

Following prior rulemakings and litigation related to regulations for GHG emissions from EGUs, on May 9, 2024, the EPA published the final rule regulating GHGs from existing EGUs pursuant to Section 111(d) of the Clean Air Act and effective on July 8, 2024. Existing EGUs are those that were constructed prior to January 8, 2014. Depending on various EGU-specific factors, the bases of emissions guidelines for natural gas-fired units include the use of uniform fuels and routine methods of operation and maintenance and the bases of emissions guidelines for coal-fired units include 40% natural gas co-firing or carbon capture and sequestration with 90% capture of CO_2 depending on the date that coal operations cease. Specific standards for performance for EGUs will be established through a State Plan (or a Federal Plan if a state were to not submit an approvable plan). The May 2024 rule is subject to legal challenges.

On June 17, 2025, the EPA published a proposed rule to repeal the May 9, 2024 final rules for new and existing EGUs in addition to 2015 greenhouse gas new source performance standards for certain new EGUs. In this proposed rule, the EPA also offered an alternative proposal to repeal a narrower set of greenhouse gas requirements which would include the repeal of requirements for existing EGUs and requirements based on carbon capture and sequestration for new EGUs. On September 16, 2025, the EPA published a proposed rule to remove certain greenhouse gas emissions reporting obligations from source categories, including electricity generation and electrical transmission and distribution equipment use. On February 18, 2026, the EPA published the final rule to rescind the 2009 greenhouse gas endangerment finding (which had concluded that greenhouse gases endanger public health and welfare). It is too early to determine the potential impact of these rules, and the results of further proceedings and potential future greenhouse gas emissions regulations remain uncertain, but could be material.

Following prior withdrawal and rejoining, in January 20, 2025, President Trump issued an Executive Order titled "Putting America First in International Environmental Agreements" directing the U.S. Ambassador to the United Nations to formally withdraw from the Paris Agreement. The international community has and continues to gather annually for the Conference to the Parties on the UN Framework Convention on Climate.

As such, there is some uncertainty with respect to the impact of GHG rules. 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.

Certain AES Southland OTC units were required to be retired to provide interconnection capacity and/or emissions credits prior to startup of new (air cooled) generating units, and the remaining AES OTC generating units in California have been or will be shut down and permanently retired by the applicable OTC Policy compliance dates for the respective units. The SWRCB OTC Policy currently requires the shutdown and permanent retirement of the remaining OTC generating units at AES Huntington Beach, LLC and AES Alamitos, LLC by December 31, 2026, as extended in support of grid reliability. This extension compliance date is contingent upon the facilities participating in the Strategic Reserve established by AB 205.

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. The Company anticipates that compliance with CWA Section 316(b) regulations and associated costs could have a material impact on our consolidated financial condition or results of operations.

Water Discharges — The concept of Waters of the United States ("WOTUS") defines the geographic reach and authority of the U.S. Army Corps of Engineers and the EPA (together, 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 the “Revised Definition of ‘Waters of the United States’” rule. This final rule amendment conforms the definition to the definition adopted in the Decision. On March 12, 2025, the Agencies issued a joint guidance memorandum for implementing the “continuous surface connection” consistent with the Decision and related issues. On March 24, 2025, the Agencies published notice outlining a process to gather recommendations for implementation of WOTUS. On November 20, 2025, the Agencies proposed revisions to align the definition of WOTUS with the Decision to clarify federal jurisdiction under CWA. 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. AES Indiana Petersburg has installed a dry bottom ash handling system in response to the CCR rule and wastewater treatment systems in response to the NPDES permits in advance of the ELG compliance date. Other U.S. businesses already include dry handling of fly ash and bottom ash and do not generate flue gas desulfurization wastewater. 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. On May 9, 2024, the EPA published a final rule which became effective on July 8, 2024. The final rule established more stringent best available technology limits for flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate and established a new set of definitions and new limits for combustion residual leachate and legacy wastewater. The May 2024 rule is subject to legal challenges. On October 10, 2024, the Eighth Circuit Court denied stay applications. On October 2, 2025, the EPA published a proposed rule that, if finalized, would extend certain ELG deadlines and allow facilities to choose between compliance alternatives. On the same date, the EPA also published a direct final rule to extend the deadline for power plants to file a notice of planned participation for the permanent cessation of coal from December 31, 2025, to December 31, 2031 pending any significant adverse comments. On November 28, 2025, the EPA withdrew the direct final rule due to receipt of adverse comments. On December 31, 2025, EPA published a final rule that extended ELG deadlines for bottom ash transport water, flue gas desulfurization wastewater, and combustion residual leachate, allowed facilities to choose between compliance alternatives, and extended the deadline for power plants to file a notice of planned participation for the permanent cessation of coal from December 31, 2025, to December 31, 2031. The rule is subject to legal challenges. 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. However, in February 2025, the EPA pulled back the guidance before it cleared the Office of Management and Budget. 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 existing CCR landfills and CCR surface impoundments, including location restrictions, design and operating criteria, groundwater monitoring, corrective action and closure requirements, and post-closure care. The 2016 Water Infrastructure Improvements for the Nation Act ("WIN Act") 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. Following prior rulemaking development and comment periods, on December 18, 2025, the Indiana Environmental Rules Board adopted a final CCR rule that includes regulation of CCR through a state permitting program. The rule and permitting program would become effective upon approval by the EPA. The EPA has indicated that it will implement a phased approach to amending the CCR Rule, which is ongoing. It is too early to determine the direct or indirect impact of these letters or any determinations that may be made.

On May 8, 2024, the EPA published final revisions to the CCR rule which expand the scope of CCR units regulated by the CCR Rule to include legacy surface impoundments, inactive surface impoundments, and CCR management units. The May 8, 2024 revisions to the CCR Rule are currently subject to legal challenges. On February 10, 2026, the EPA published a final rule extending certain deadlines for coal combustion residual management units associated with its May 8, 2024 revisions to the CCR Rule. It is too early to determine the potential impact from these revisions to the CCR Rule.

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.

Trump Administration Actions Affecting Environmental Regulations — On January 20, 2025, President Trump issued an Executive Order titled "*Unleashing American Energy*" directing Agencies to, among other tasks, review regulations issued under the prior Administration to determine whether they should be suspended, revised, or rescinded. The Trump Administration also issued a Memorandum titled "*Regulatory Freeze Pending Review*" directing Agencies to refrain from proposing or issuing any rules until the Trump Administration has reviewed and approved those rules. In accordance with these and other Trump Administration Executive Orders, on March 12, 2025, the EPA released a list of environmental regulations that will be targeted for reconsideration and other deregulatory action. These and other actions, including other Executive Orders and directives from the Trump Administration, may have an impact on regulations and permitting processes that may affect our business, financial condition, or results of operations.

International Environmental Regulations

Chile

During the 2020s, Chile developed a decarbonization and climate adaptation framework that requires a reorientation of the planning of the electricity sector: the Framework Law on Climate Change (published in June 2022) sets long-term objectives, including emissions neutrality, and creates instruments to integrate mitigation and adaptation into sectoral policies that condition permits, planning, and technical requirements in generation and transmission.

In 2023, increasingly demanding environmental regulations were issued, which require adjustments in controls throughout the life cycle of any investment project in the development, construction, and operation phase. Environmental prevention and management models were adjusted to prevent behaviors that could be considered environmental crimes, and investments were undertaken to comply with new regulatory standards.

In February 2024, Supreme Decree No. 30/2023 came into effect, amending the Regulations of the Environmental Impact Assessment System to align them with obligations arising from the Framework Law on Climate Change (Law 21.455) and the Escazú Agreement. The new regulations introduce more stringent criteria for environmental assessment.

In September 2025, Law No. 21.770, the Framework Law on Sectoral Authorizations, was enacted and published in the Official Gazette. This law establishes a general framework for sectoral permitting processes for regulated projects with the aim of simplifying, standardizing, and coordinating the various administrative procedures across different government agencies. The legislation seeks to reduce processing times for sectoral permits by an estimated 30% to 70%.

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.

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).

See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Macroeconomic and Political—Argentina* for further discussion on regulations impacting energy matters.

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. As a result of the introduction of non-conventional renewable energy projects, various regulations were issued regarding the environmental permits applicable to these types of projects and the participation of indigenous communities in environmental licensing processes.

The following is a summary of the environmental regulatory issues that were formalized in 2024 and 2025:

- Renewable energy projects with an installed capacity equal to or greater than 50 MW will be licensed by ANLA. Previously, the limit was 100 MW.
- Decree 1275 of 2024 was issued, which establishes the environmental authority powers of indigenous communities in their territories.

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. During 2025, ANLA issued an environmental license modification for the connection line to cover the complete infrastructure of the project and started the environmental licensing process for the Jemeiwaa Ka'I 4 wind project.

Customers

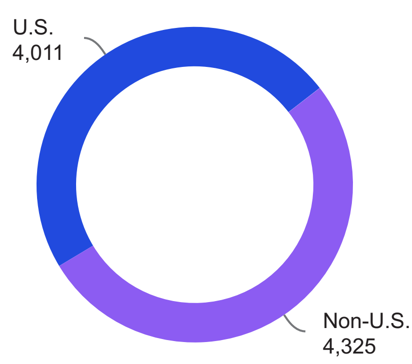
We sell to a wide variety of customers. No individual customer accounted for 10% or more of our 2025 total revenue. In our generation business, we own and/or operate power plants to sell power to wholesale customers such as utilities and other intermediaries, as well as to large corporations. Our utilities 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 Global Leadership Team with the guidance and oversight of our Board of Directors. Governance and standards for AES people are guided by the Chief Human Resources Officer, with input from members of the Global Leadership Team.

As of December 31, 2025, the Company and its subsidiaries had 8,336 full time/permanent employees.

Full Time/Permanent Employees



As of December 31, 2025, approximately 31% 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 2026 to 2027. In addition, certain employees in non-U.S. locations were subject to collective bargaining agreements, representing approximately 48% of the non-U.S. workforce. As of December 31, 2025, approximately 25% of our U.S. and non-U.S. workforce is part of bargaining agreements expiring on or before December 31, 2026. 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 ISO 45001 standard, and during 2025 approximately 48% of our locations (excluding renewable assets in the United States, more than 80% of which are smaller than 20 MW) have elected to formally certify their SMS to the 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 2025, there was an 11% decrease in AES' LTI cases. In 2025, AES’ LTI Rate was 0.086 for AES People, 0.118 for operational contractors, and 0.000 for construction contractors. In 2025, the Company did not have any work-related fatalities.

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.

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, 54 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’ renewables portfolio. Mr. Coughlin is a member of the boards of AES Clean Energy Development Holdings, LLC, AES U.S. Investments, Inc., 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, 62 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 President and Chief Executive Officer of AES Clean Energy Development, and a member of the boards of IPALCO, AES Andes, AES Mong Duong Power Co. Ltd., 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, 46 years old, was appointed President effective March 2, 2026. Prior to assuming his current position, Mr. Falú served as Executive Vice President and Chief Operating Officer since February 2024, Senior Vice President and Chief Operating Officer from July 2023 to February 2024 and Senior Vice President and Chief Strategy and Commercial Officer from August 2022 to July 2023. From March 2023 to March 2026, Mr. Falú 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 IPALCO, Fluence Energy, Inc., AES Andes, DPL, 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, 56 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, 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, 68 years old, has been Chief Executive Officer and a member of our Board of Directors since September 2011 and is a member of the Innovation and Technology Committee. He also served as President from September 2011 to March 2026. 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, 50 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, and Fluence Energy, Inc., 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*,* 49 years old, was appointed as Executive Vice President, Chief Operating Officer and President of the Energy Infrastructure SBU effective March 2, 2026. Prior to assuming his current position, Mr. Rubiolo served as Executive Vice President and President of the Energy Infrastructure SBU since March 2023, 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, and AES Colombia. 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 May 20, 2025.

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.

Our renewable energy projects and other initiatives face considerable uncertainties.

Wind, solar, and energy storage projects are subject to substantial risks. In particular, in the U.S., AES' renewable energy generation growth strategy has depended 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, REC mechanisms and compliance programs, and tax exemptions. More recently, the favorable regulatory regimes associated with the U.S. Inflation Reduction Act of 2022 have been curtailed by the passage of H.R. 1 (the "2025 Act"). See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Macroeconomic and Political—U.S. Tax Law Reform and U.S. Renewable Energy Tax Credits*. If these policies and incentives are further changed or eliminated, if pending tax guidance related to these policies is adverse, or AES is otherwise unable to use these policies or incentives, there could be a material adverse impact on AES' U.S. renewable growth opportunities, including fewer future PPAs, decreased revenues, reduced economic returns on certain project company investments, increased financing costs, and/or difficulty obtaining financing. Further, the adoption of the 2025 Act requires the issuance of tax guidance, some of which has not yet been issued, that may further impact our projects.

In addition, new tariffs, duties, or other assessments have been 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 are further 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 and battery storage projects and the average time for receiving interconnection approvals is over four years, with significant variations across projects and regions. Our existing interconnection requests may also be subject to regulatory changes that could negatively impact the timing or cost associated with obtaining interconnection approval. Some RTOs, such as PJM, have recently implemented or are considering accelerated or supplemental interconnection processes for high-capacity factor resources or for resources that service a resource adequacy need or new load, which could result in delays or cost increases to existing or future interconnection requests of intermittent renewable energy projects, such as solar and wind. Additional measures could be considered by RTOs, transmission owners, or governmental authorities to foster or accelerate deployment or utilization of certain high-capacity factor technologies in a manner that negatively impacts the development of solar or wind 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. These upgrades may also be delayed by the accelerated or supplemental interconnection of high-capacity factor resources, as discussed above.

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.

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.

Volatility in wholesale prices 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.

Further, the Chinese market has driven global materials demand and pricing for commodities, many of which are produced in our key electricity markets in South America. Volatility in economic growth in China could result in lower economic growth and lower demand for electricity in our key markets.

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 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.

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.

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 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. Additionally, we store and use customer, employee, and other personal information and other confidential and sensitive information. 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 various geopolitical conflicts. 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 of our systems or certain of our third-party vendor systems may:

- impact our operations, revenue, strategic objectives, or customer and vendor relationships;
- expose us to negative publicity, legal claims, regulatory investigations and proceedings and associated penalties or liabilities;
- 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 breaches 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 our joint ventures or our equity method investments and cannot guarantee that their efforts will be effective.

Highly infectious or contagious diseases outbreaks could impact our business and operations.

Regional or global outbreaks of infectious or contagious diseases, such as occurred during the COVID-19 pandemic, could have material and adverse effects on our results of operations, financial condition, and cash flows due to, among other factors:

- decline in customer demand as a result of general decline in business activity;
- 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;
- 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 a work-from-home environment;
- 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 related losses and the review and approval of our rates at our U.S. regulated utilities.

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

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 snowpack 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 Colombia in 2024, 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, wildfires 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 otherwise fails 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, or may assume additional obligations in order to preserve such projects.

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. In recent years, Fluence has reported a material weakness in its internal control over revenue recognition that was remediated as of December 31, 2024. If there is a material weakness in the future, that 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 the 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 29 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 16—*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 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 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 2025, the Company's subsidiaries operated businesses that had total direct CO_2 equivalent emissions of approximately 29 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. 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 9, 2024, the EPA published the final NSPS requiring carbon capture and sequestration for new and reconstructed baseload stationary combustion turbines, among other requirements. The EPA did not finalize revisions to the NSPS for newly constructed or reconstructed coal-fired electric utility steam generating units as proposed in 2018. 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 9, 2024, the EPA published the final rule regulating GHGs from existing EGUs pursuant to Section 111(d) of the Clean Air Act and effective on July 8, 2024. Existing EGUs are those that were constructed prior to January 8, 2014. Depending on various EGU-specific factors, the bases of emissions guidelines for natural gas-fired units include the use of uniform fuels and routine methods of operation and maintenance and the bases of emissions guidelines for coal-fired units include 40% natural gas co-firing or carbon capture and sequestration with 90% capture of CO_2 depending on the date that coal operations cease. Specific standards for performance for EGUs will be established through a State Plan (or a Federal Plan if the state of Indiana were to not submit an approvable plan). The May 2024 rule is subject to legal challenges. On February 18, 2026, the EPA published a final rule to rescind the 2009 greenhouse gas endangerment finding (which had concluded that greenhouse gases endanger public health and welfare). 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. 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. Regulation, such as the initiatives in Chile and the Puerto Rico Energy Public Policy Act, may adversely affect our operations. 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. In the U.S., the IRA includes a 15% corporate alternative minimum tax based on adjusted financial statement income. In June 2025, the IRS began releasing interim guidance for CAMT and announced its intention to revise regulations that were proposed in September 2024. The impact to the Company in 2025 is not material. We will continue to monitor the issuance of CAMT revised guidance.

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 required EU Member States to transpose the Directive into their respective national laws by December 31, 2023 for the rules to have come into effect as of January 1, 2024. The Netherlands, Bulgaria, and Vietnam adopted legislation to implement Pillar 2 effective as of January 1, 2024. The impact to the Company during 2025 was not material. On January 5, 2026, the OECD published a side-by-side package to modify the Pillar 2 system in a manner that will fully exclude domestic and foreign profits of US-parented groups from Pillar 2’s Undertaxed Profits Rule and Income Inclusion Rule. The side-by-side package is intended to take effect as of January 1, 2026, but is subject to enactment of legislation in the local jurisdictions. We will continue to monitor the issuance of 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, 2025, we had approximately $30 billion of outstanding indebtedness on a consolidated basis. All outstanding borrowings under The AES Corporation's revolving credit facilities 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 12—*Obligations* 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, 2025, we had approximately $30 billion of outstanding indebtedness on a consolidated basis, of which approximately $6.0 billion was recourse debt of the Parent Company and approximately $23.2 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 $20 million as of December 31, 2025. 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 facilities 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 facilities 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 to 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 and/or transferability tax credit buyers; 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 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.

Failure to maintain an effective system of internal control over financial reporting could result in material misstatements in our financial statements or may negatively impact investor confidence in our reported financial information.

Our internal controls, accounting policies, and practices are designed to enable us to evaluate transactions in a timely and accurate manner in compliance with GAAP, laws and regulations, taxation requirements, and federal securities laws and regulations in order to, among other things, disclose and report financial and other information in connection with our reporting requirements under federal securities, tax, and other laws and regulations. We have also implemented corporate governance, internal controls, and accounting policies and procedures in connection with the Sarbanes-Oxley Act of 2002. Our internal controls and policies have been and continue to be closely monitored by management and our Board of Directors. While we believe these controls, policies, practices, and systems are adequate to accurately and fairly reflect the transactions and dispositions of the assets of the Company, the identification of significant deficiencies or material weaknesses in our internal controls that we cannot remediate in a timely manner could lead to undetected errors that could result in material misstatements in our financial statements.

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' Vice President Cybersecurity acts as the Chief Information Security Officer ("CISO"), reports to our Chief Digital Officer, 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 and has served in that position since 2024.

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 Global Leadership Team, as well as the Vice President Global Financial Planning and Analytics, Vice President Global 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, 2025. Pursuant to SEC amendments Item 103 of SEC Regulation S-K, AES' policy is to disclose environmental legal proceedings to which a government 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 $11 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 an 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 has since followed up with the City and awaits the next phase of the permitting process. 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.

On March 23, 2021, the U.S. District Court for the Southern District of Indiana approved and entered a judicial consent decree among AES Indiana, the United States on behalf of the Environmental Protection Agency ("EPA"), and the Indiana Department of Environmental Management (“IDEM”). The decree resolved allegations by EPA and IDEM that AES Indiana had violated the federal Clean Air Act (“CAA”) at its Petersburg Station, which AES denies. Under the decree, AES Indiana agreed to certain emission limits and annual caps on NOx, SO_2 and PM emissions at the four Units at the station; paid a civil penalty of $1.525 million; retired Units 1 and 2, spent $325,000 on an environmentally beneficial project to preserve local, ecologically-significant lands (notice of completion of which was provided May 8, 2025 and confirmed satisfactory by IDEM on September 8, 2025); and will spend a total of $5 million on a further environmental mitigation project to build and operate a new, non-emitting source of generation at the site.

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 AES companies have moved to dismiss the lawsuit. That motion has been briefed and argued, and is under consideration by the relevant court of first instance. The 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, namely, the Civil Court of La Vega (“CFI”). In May 2024, the CFI dismissed the entire case due to the expiry of the statute of limitations. Later in 2024, the claimants appealed the dismissal to the relevant intermediate appellate court. The appellate court heard the parties’ respective oral arguments in September 2025. A decision on the appeal is pending. 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. AES Andes has completed the Compliance Program and is planning to file its final report in Q3-2025. The SMA will review the final report. If the SMA approves the final report, the Compliance Program will be considered fully completed, and thus any alleged charges associated with the same will be considered permanently waived. Separately, 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 request 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 the proposed Compliance Program is approximately $10.8 million and is in the execution stage. Fines are possible if the SMA determines there is an unsatisfactory execution of the Compliance Program. 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. On May 10, 2024, the Company was notified of a fine for $180,515. On June 3, 2024, the Company appealed this fine to the Environmental Court. The appellate hearing occurred on April 3, 2025; the Environmental Court’s decision on the appeal is pending. The Company believes that it has meritorious defenses and will continue to assert them vigorously in this dispute; however, there can be no assurances that it will be successful.

On May 12, 2021, the Mexican Federal Attorney for Environmental Protection (the “Agency”) initiated an environmental audit at the Termoeléctrica del Peñoles thermal generation facility (“TEP”). On January 20, 2023, TEP was notified of the resolution issued by the Agency, which alleges breaches of air emission regulations, including the failure to submit reports. The resolution imposes a fine of $27,615,140 pesos (approximately $1.5 million), as well as a series of corrective measures. On March 3, 2023, TEP filed a lawsuit in an administrative court —The Specialized Chamber of the Federal Administrative Justice Tribunal (“Chamber”)—challenging the legality of the Agency’s resolution and fine. On May 30, 2025, the Chamber issued a final administrative ruling denying TEP’s lawsuit. On July 1, 2025, TEP appealed to the Federal District Court. TEP’s appeal challenges the constitutionality of the Agency’s regulations (*demanda de amparo*) and requests a stay of enforcement of the Chamber’s final administrative ruling. The appeal has been duly admitted and the Federal District Court’s decision on the injunction request is pending. 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. In February 2024, at the request of the Company, the Dominican Supreme Court of Justice transferred the case to a different civil court, namely, the Civil Court of La Vega (“CFI”). The claimants’ attempt to recuse the presiding judge has been rejected by the relevant Dominican appellate court. The parties have completed briefing on the Company’s motion to dismiss the lawsuit. That motion is under consideration by the CFI. 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 January 26, 2023, the SMA notified Alto Maipo SpA of four alleged charges relating to the Alto Maipo facility, all of which are categorized by the SMA as “serious.” The alleged charges include: untimely completion of certain intake works; insufficient capture species; non-compliance with certain forest management plan goals; and intervention of a restricted paleontological area. On February 16, 2023, the Alto Maipo project submitted an initial compliance program to the SMA. On December 9, 2024, the SMA rejected an updated version of the compliance program. On December 16, 2024, Alto Maipo submitted a petition for reconsideration of the rejection, which SMA denied on October 13, 2025. On October 15, 2025 Alto Maipo submitted to SMA its defense response to the four alleged charges. If Alto Maipo’s defense response arguments are not acceptable to the SMA, the imposition of fines is possible. Separately, Alto Maipo filed a legal action seeking annulment of the decision that rejected its proposed compliance program.

In April 2025, an alleged shareholder of Fluence Energy, Inc. (“Fluence”) filed a putative securities class action in the U.S. District Court for the Eastern District of Virginia (“Court”) against Fluence and certain of Fluence’s officers and directors. The complaint in the case also named the Company and AES Grid Stability, LLC as defendants (together, the “AES Defendants”). In May 2025, the Court consolidated the lawsuit with another putative securities class action against Fluence and certain of its officers and directors. The Court also appointed a lead plaintiff (the “Plaintiff”) and lead plaintiffs’ counsel for the consolidated lawsuit. In June 2025, the Plaintiff filed a consolidated amended complaint against Fluence, certain of its officers and directors (the “Individual Fluence Defendants” and, together with Fluence, the “Fluence Defendants”), and the AES Defendants. The Plaintiff seeks to pursue claims on behalf of a putative class of all purchasers of Fluence Class A common stock between October 28, 2021 and February 10, 2025. The Plaintiff alleges that the Fluence Defendants made allegedly false or misleading statements in violation of Section 10(b) of the Securities Exchange Act of 1934 (the “Exchange Act”), as well as Rule 10b-5 promulgated thereunder. In addition, the Plaintiff asserts claims against the Individual Fluence Defendants and the AES Defendants as alleged “control persons” under Section 20(a) of the Exchange Act. In July 2025, the Fluence Defendants and the AES Defendants filed separate motions to dismiss the consolidated lawsuit. The motions are now fully briefed and pending before the Court. The AES Defendants believe that they have meritorious defenses to the claims asserted against them and will defend themselves vigorously in this lawsuit; however, there can be no assurances that they will be successful in their efforts.

In May 2025, a special session of the Federal Regional Court of the 1st Region of Brazil ("TRF1”) issued a decision dismissing the claims of Sul, which was sold to a third party in 2016 (“Buyer”), to annul ANEEL’s Order 288. Order 288 was issued in May 2002 and retroactively changed the effects of the Wholesale Energy Market (“MAE”) for the year 2001. The aggregate impact of Order 288 for AES Sul was to reverse a gain on certain purchases and sales into an approximately R$75 million ($14 million) loss, estimated as of May 2002. The TRF1’s May 2025 decision reversed its April 2013 decision in Sul’s favor that annulled Order 288. In August 2025, Sul filed a motion for clarification of the decision with the TRF1, which is considering the motion. After the motion is decided, Sul will have the ability to file appeals with the Superior Court of Justice and the Supreme Federal Court. In the event of an unsuccessful outcome for Sul, the Buyer may attempt to seek recovery of losses relating to the R$75 million ($14 million) loss above, an additional amount of approximately R$27 million ($5 million) that was collected by Sul in 2008 and may need to be reimbursed, plus interest on these amounts, from the AES seller and The AES Corporation under the sale agreement. In that event, AES would defend itself vigorously; however, there can be no assurances that it would be successful in its efforts.

On May 30, 2025, an arbitral tribunal (the “Tribunal”) of the International Centre for the Settlement of Investment Disputes (“ICSID”) issued an arbitration award in the Company’s favor (“Award”) in connection with a treaty arbitration initiated by the Company against the Argentine Republic (“Argentina”) under the US-Argentina bilateral investment treaty (“BIT”). In the Award, the Tribunal found that certain measures taken by Argentina in relation to its power sector, beginning in late 2001, breached the BIT. The Tribunal ordered Argentina to pay to the Company approximately $733 million in damages, including an award of costs, as well as accrued interest. In August 2025, the Company filed a lawsuit in the U.S. District Court for the District of Columbia (“DDC”) to recognize and enforce the ICSID Award against Argentina. In September 2025, Argentina filed an application with ICSID to annul the Tribunal’s Award. In its application, Argentina also requested a stay of enforcement of the Award pending the completion of the annulment proceedings ("Stay Request"). Argentina’s annulment application, as well as its Stay Request, will be decided by a new three-person panel appointed by ICSID (“Annulment Panel”). In January 2026, ICSID appointed the Annulment Panel. The Company has opposed Argentina's Stay Request. Pending the Annulment Panel's decision on the Stay Request, the Company’s enforcement efforts in the DDC will be provisionally stayed. The Company can provide no assurance as to how the Annulment Panel will rule on Argentina’s Stay Request or the merits of the annulment application. Relatedly, measures to enforce the Award through judicial means entail a process that is inherently unpredictable; as a result, the Company cannot provide any assurance as to the timing or success of such enforcement measures. The Company may attempt to settle this dispute with Argentina. However, the Company can provide no assurances regarding the likelihood, substance, or timing of any such settlement.

On December 30, 2025, The Company received a complaint filed in Virginia state court by Sinolam LNG Terminal, SA and Sinolam Smarter Energy LNG Power Co. (collectively, “Plaintiffs”) against the Company, AES Latin America, S. de R.I., AES Panama, S.R.I. (“AES Panama”), AES Colon Holdings, S. de R.I., Costa Norte LNG Terminal S. de. R.I., Gas Natural del Atlantico S. de R.I., InterEnergy Holdings (UK) Limited (“IEHL”) (a third party), and Group Energy Gas Panama S. de. R.I. (a partnership between IEHL and AES Panama) (collectively, “Defendants”). In their complaint, the Plaintiffs allege that the Defendants interfered with the Plaintiffs’ efforts to develop an LNG-fired power plant and an LNG terminal in Panama. The Plaintiffs appear to seek recovery of alleged lost profits totaling about $4 billion, alleged out-of-pocket damages, interest, statutory damages, and other relief from the Defendants. The Company believes that it has meritorious defenses to the claims asserted against it and will defend itself vigorously in this lawsuit; however, there can be no assurances that it will be successful in its efforts.

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, purchases by contract (including, without limitation, accelerated stock repurchase programs or 10b5-1 plans), 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, 2025 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, 2025, $264 million remained available for repurchase under the Stock Repurchase Program. No repurchases were made by The AES Corporation of its common stock in 2025, 2024, and 2023.

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 increased this dividend annually until 2025. The quarterly per-share cash dividends for the last three years are displayed below.

Commencing the fourth quarter of	**2025**	**2024**	**2023**
Cash dividend	$0.17595	$0.17595	$0.1725

The fourth quarter 2025 cash dividend was paid on February 13, 2026. The first quarter 2026 cash dividend was declared on February 19, 2026 and is consistent with the fourth quarter 2025 cash dividend. 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.

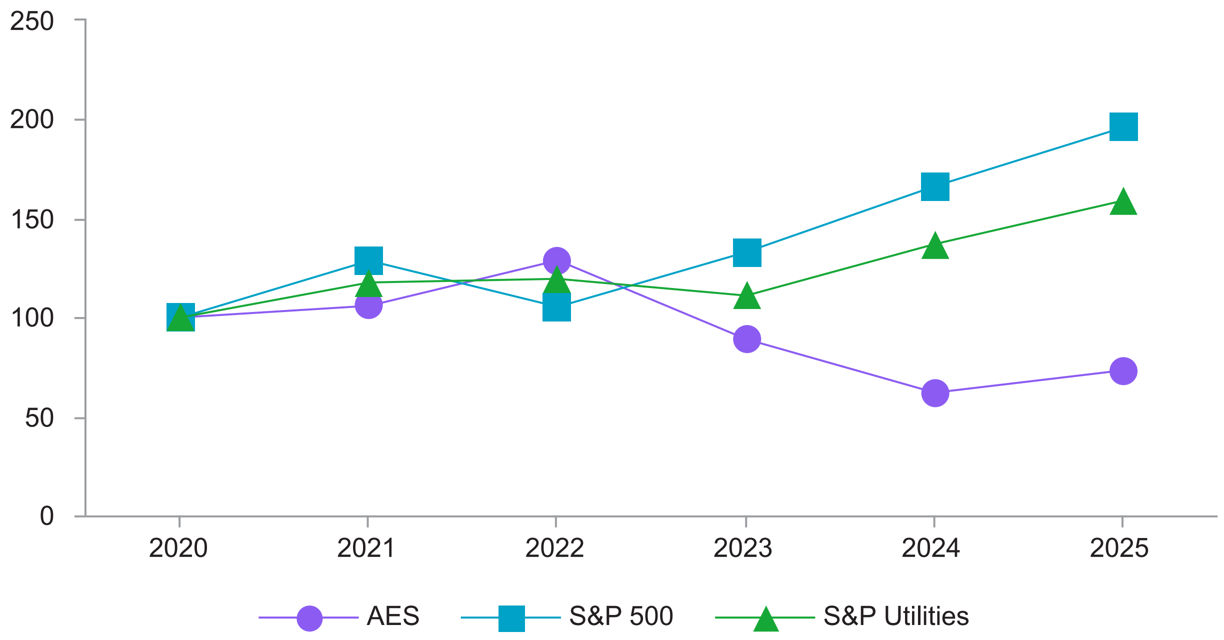
Under the terms of our revolving credit facilities, which we entered into with commercial bank syndicates, we have limitations on our ability to pay cash dividends and/or repurchase stock. Our subsidiaries' ability to declare and pay cash dividends to us is also subject to certain limitations contained 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 26, 2026, there were approximately 3,219 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 31 electric and gas utilities included in the S&P 500.

The five-year total return chart assumes $100 invested on December 31, 2020 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, 2024 compared to the year ended December 31, 2023, refer to Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations* in our 2024 Form 10-K filed with the SEC on March 11, 2025.

Executive Summary

In 2025, AES delivered on its strategic and financial objectives. We completed construction of 3.2 GW of renewables and energy storage, and signed long-term PPAs for an additional 4.0 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 income decreased $640 million, from $802 million to $162 million. This decrease is mainly driven by the prior year gain on sale of AES Brasil, lower earnings at the Energy Infrastructure SBU primarily due to higher prior year revenues from the monetization of the Warrior Run coal plant PPA and lower net derivative gains, higher day-one losses on the commencement of sales-type leases at AES Clean Energy, and higher unrealized foreign currency losses; partially offset by income tax benefit mainly driven by tax credit transfers compared to prior year income tax expense, higher contributions from new projects and better hydrology in the Renewables SBU, and higher retail margin at the Utilities SBU under the 2024 Base Rate Order at AES Indiana and the 2024 DRC Settlement at AES Ohio.

Adjusted EBITDA, a non-GAAP measure, increased $232 million, from $2,639 million to $2,871 million, mainly driven by higher contributions from new projects and better hydrology in the Renewables SBU, and higher retail margin at the Utilities SBU; partially offset by higher prior year revenues from the monetization of the Warrior Run coal plant PPA in the Energy Infrastructure SBU, the sale of AES Brasil in the prior year, and the impact of the AES Ohio and AGIC sell-downs.

Adjusted EBITDA with Tax Attributes, a non-GAAP measure, increased $459 million, from $3,952 million to $4,411 million, primarily due to the drivers above as well as higher realized tax attributes driven by higher income from tax credit transfers.

Compared with last year, diluted earnings per share from continuing operations decreased $1.06, from $2.37 to $1.31. This decrease is mainly driven by the prior-year gain on sale of AES Brasil, lower earnings at the Energy Infrastructure SBU primarily due to higher prior year revenues from the monetization of the Warrior Run coal plant PPA and lower net derivative gains, higher day-one losses on commencement of sales-type leases at AES Clean Energy, higher unrealized foreign currency losses, and impairments related to Uplight. These were partially offset by higher income tax benefit mainly driven by tax credit transfers compared to prior year income tax expense, and contributions from new projects and better hydrology in the Renewables SBU.

Adjusted EPS, a non-GAAP measure, increased $0.20 from $2.14 to $2.34, mainly driven by a lower adjusted tax rate, including the impact of tax credit transfers, and higher realized tax attributes and retail margin at the Utilities SBU; partially offset by lower realized tax attributes at the Renewables SBU due to timing of tax attribute recognition and lower contributions from the Energy Infrastructure SBU primarily due to higher prior year revenues from the monetization of the Warrior Run coal plant PPA.

Review of Consolidated Results of Operations

Years Ended December 31, (in millions, except per share amounts)	2025	2024	$ Change	% Change
Revenue:				
Renewables SBU	$ 2,913	$ 2,617	$ 296	11%
Utilities SBU	4,122	3,608	514	14%
Energy Infrastructure SBU	5,402	6,207	(805)	-13%
New Energy Technologies SBU	1	1	—	—%
Corporate and Other	149	162	(13)	-8%
Eliminations	(354)	(317)	(37)	-12%
Total Revenue	12,233	12,278	(45)	—%
Operating Margin:				
Renewables SBU	503	399	104	26%
Utilities SBU	635	543	92	17%
Energy Infrastructure SBU	901	1,233	(332)	-27%
New Energy Technologies SBU	(11)	(7)	(4)	-57%
Corporate and Other	268	267	1	—%
Eliminations	(85)	(121)	36	30%
Total Operating Margin	2,211	2,314	(103)	-4%
General and administrative expenses	(241)	(288)	47	-16%
Interest expense	(1,407)	(1,485)	78	-5%
Interest income	287	381	(94)	-25%
Loss on extinguishment of debt	(26)	(17)	(9)	53%
Other expense	(458)	(175)	(283)	NM
Other income	67	156	(89)	-57%
Gain on disposal and sale of business interests	58	351	(293)	-83%
Asset impairment expense	(224)	(374)	150	-40%
Foreign currency transaction gains (losses)	(79)	31	(110)	NM
Other non-operating expense	(113)	—	(113)	NM
Income tax benefit (expense)	181	(59)	240	NM
Net equity in losses of affiliates	(55)	(26)	(29)	NM
INCOME (LOSS) FROM CONTINUING OPERATIONS	201	809	(608)	-75%
Loss from disposal of discontinued businesses, net of income tax expense of $0 and $7, respectively	(39)	(7)	(32)	NM
NET INCOME (LOSS)	162	802	(640)	-80%
Less: Net loss attributable to noncontrolling interests and redeemable stock of subsidiaries	748	877	(129)	-15%
NET INCOME ATTRIBUTABLE TO THE AES CORPORATION	$ 910	$ 1,679	$ (769)	-46%
Net cash provided by operating activities	$ 4,306	$ 2,752	$ 1,554	56%

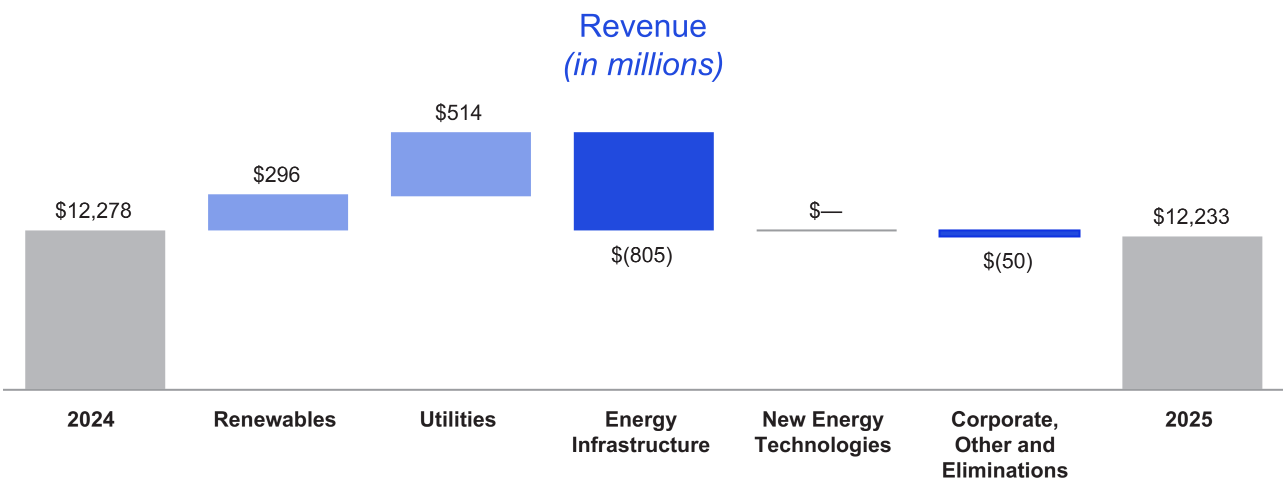
Components of Revenue, Cost of Sales, and Operating Margin — Revenue includes revenue earned from the sale of energy from our utilities and the production and sale of energy from our generation plants, which are classified as regulated and non-regulated, respectively, on the Consolidated Statements of 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, O&M 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, 2025

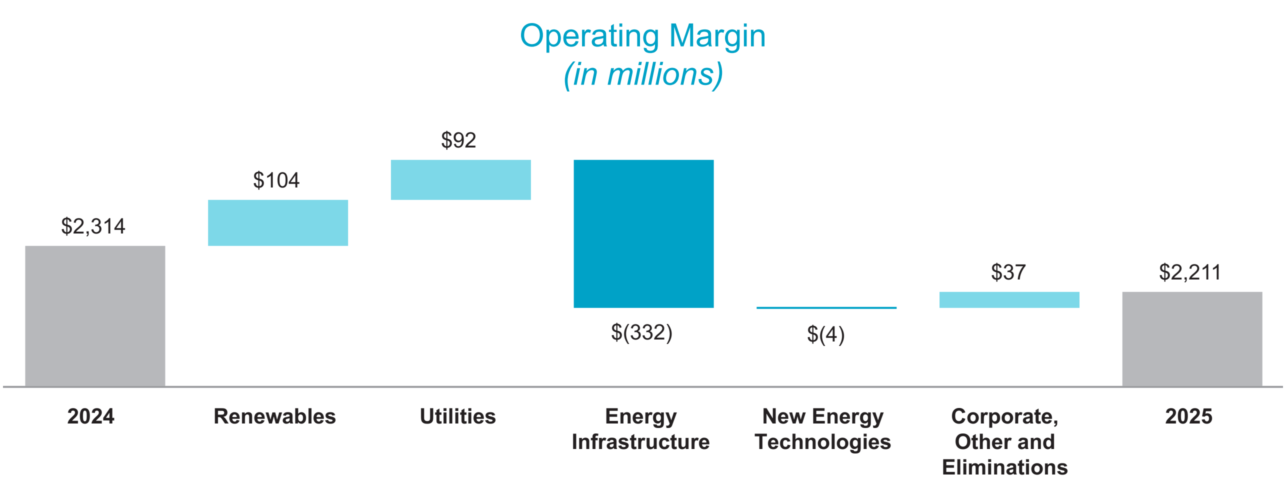


Consolidated Revenue — Revenue decreased $45 million in 2025 compared to 2024, driven by:

- $805 million at Energy Infrastructure primarily driven by $921 million of prior year revenue related to the AES Andes portfolio, which is reported in the Renewables SBU beginning in 2025 following the sale and expiration of certain coal-related assets and contracts; $174 million due to prior year unrealized and realized derivative gains, $171 million of prior year revenues from the monetization of the Warrior Run coal plant PPA, and $23 million due to the prior year sell-down of Amman East and IPP4 in Jordan; partially offset by $317 million due to higher fuel prices and transportation costs passed through to the offtaker, $148 million of higher CO_2 purchases passed through due to higher production, and $28 million due to higher availability; and
- $50 million at Corporate, Other and Eliminations mainly driven by higher eliminations of inter-segment revenue.

These unfavorable impacts were partially offset by increases of:

- $514 million at Utilities mainly driven by $422 million increase in transmission, distribution, rider, and wholesale revenues mainly due to higher rates, and $93 million due to higher net retail demand mainly driven by favorable weather; and
- $296 million at Renewables mainly driven by an $832 million increase due to the results of AES Andes moving to Renewables in 2025, as described above, net of a current year decrease in regulated contract sales, $232 million due to new projects in service, and $105 million due to development services in the U.S.; partially offset by a $615 million decrease due to the sale of AES Brasil, $243 million net lower spot sales and prices, mainly in Colombia, and a $42 million decrease related to changes in mark-to-market of energy derivatives.



Consolidated Operating Margin — Operating margin decreased $103 million, or 4%, in 2025 compared to 2024, driven by:

- $332 million at Energy Infrastructure mainly driven by $160 million higher prior year revenues from the monetization of the Warrior Run coal plant PPA, $108 million due to prior year net derivative gains as part of our commercial hedging strategy, $60 million of prior year operating margin related to the AES Andes portfolio, which is reported in the Renewables SBU beginning in 2025 following the sale and expiration of certain coal-related assets and contracts, $23 million of lower LNG sales net of higher terminal fees, $18 million of one-time costs due to restructuring, and $17 million due to the prior year sell-down of Amman East and IPP4 in Jordan; partially offset by $49 million driven by higher availability in 2025 due to lower maintenance.

These unfavorable impacts were partially offset by increases of:

- $104 million at Renewables mainly driven by $91 million due to development services in the U.S., $89 million from new businesses, $68 million in Colombia as a result of increased availability and lower spot prices on energy purchases, $60 million due to the results of AES Andes moving to Renewables in 2025, as described above, and $36 million due to higher generation in Panama as a result of better hydrological conditions during the first quarter of 2025. These increases were partially offset by a $177 million decrease due to the sale of AES Brasil, a $42 million decrease related to changes in mark-to-market of energy derivatives, a $38 million increase in fixed costs primarily related to an accelerated growth plan, and $15 million of one-time costs due to restructuring;
- $92 million at Utilities mainly driven by $191 million due to higher retail rates as a result of the AES Indiana 2024 Base Rate Order and AES Ohio 2024 DRC Settlement, higher transmission and rider revenues, and higher demand due to the impact of weather; partially offset by a $46 million increase in depreciation expense from additional assets placed in service, a $33 million increase in fixed cost mainly driven by higher property taxes, and a $14 million impact of planned outages; and
- $37 million at Corporate and Other mainly driven by higher premiums earned by AGIC and lower eliminations of insurance recoveries booked at the businesses related to AGIC.

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 decreased $47 million, or 16%, to $241 million in 2025 compared to $288 million in 2024, primarily due to a $34 million decrease in business development costs, driven by the Company's restructuring program, $18 million lower IT costs, and $8 million lower professional fees, partially offset by $14 million of one-time costs due to restructuring.

Interest expense

Interest expense decreased $78 million, or 5%, to $1,407 million in 2025, compared to $1,485 million in 2024. This decrease is primarily due to a $200 million impact from the sale of AES Brasil in October 2024 and lower debt balances at the Energy Infrastructure SBU; partially offset by lower capitalized interest at the Renewables SBU due to fewer projects under construction, and a higher weighted average interest rate and debt balance at the Parent Company.

Interest income

Interest income decreased $94 million, or 25%, to $287 million in 2025, compared to $381 million in 2024, primarily due to a $46 million impact from the sale of AES Brasil in October 2024, prior year interest recognized of $34 million on the Stabilization Fund receivables in Chile, and a $24 million decrease at Argentina due to lower short-term investments at lower rates; partially offset by a $15 million increase in sales type lease receivables at the Renewables SBU.

Loss on extinguishment of debt

Loss on extinguishment of debt increased $9 million, or 53%, to $26 million in 2025, compared to $17 million in 2024. This increase was primarily driven by a $9 million loss related to a revolver amendment and prepayment of debt at AES Clean Energy, a $7 million loss due to prepayment of debt at Jordan Solar, and a $5 million loss due to prepayment of senior notes at Mercury Chile; partially offset by a prior year loss of $10 million due to a prepayment at AES Andes.

See Note 12—*Obligations* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Other income

Other income decreased $89 million, or 57%, to $67 million in 2025, compared to $156 million in 2024 primarily due to the prior year recognition of a $20 million bargain purchase gain on the Madison and Birdseye acquisition, a prior year gain of $14 million corresponding to the step acquisition of Felix, and a prior year indexation adjustment of Stabilization Fund receivables at AES Andes of $12 million, as well as a $10 million decrease in insurance proceeds and a $7 million decrease in AFUDC at our U.S. utilities in the current year. This was partially offset by a $10 million gain at AES Andes in the current year corresponding to the write-off of contingent consideration for a renewables development project determined to be no longer viable.

Other expense

Other expense increased $283 million to $458 million in 2025, compared to $175 million in 2024 primarily driven by $159 million higher losses on commencement of sales-type leases at AES Clean Energy and AES Renewable Holdings, a $74 million increase in losses on remeasurement of contingent consideration primarily on projects acquired at AES Clean Energy, and a $48 million current year loss on remeasurement of our investment in 5B, accounted for using the measurement alternative; partially offset by a $20 million loss recognized in the prior year related to legal expenses and other direct costs associated with the troubled debt restructuring at Puerto Rico.

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

Gain on disposal and sale of business interests

Gain on disposal and sale of business decreased $293 million to $58 million in 2025, compared to $351 million in 2024. This decrease was primarily due to the prior year gain on sale of AES Brasil of $312 million and a $52 million gain in the prior year on dilution of AES' ownership interest in Uplight as a result of the AutoGrid acquisition. This was partially offset by a $70 million gain on the sell-down of Dominican Republic Renewables, which is now accounted for as an equity method investment.

See Note 9—*Investments in and Advances to Affiliates* and Note 25—*Held-for-Sale and Dispositions* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Asset impairment expense

Asset impairment expense decreased $150 million, or 40%, to $224 million in 2025, compared to $374 million in 2024. This decrease was primarily due to a $243 million increase in the carrying value of the Mong Duong asset group due to the derecognition of a valuation allowance on the loan receivable accounted for under ASC 310 and the elimination of net estimated costs to sell upon reclassifying Mong Duong from held-for-sale to held and used, and lower impairment expense of $45 million at Mong Duong and prior year impairments of $125 million and $80 million at Ventanas and AES Brasil, respectively, associated with the held-for-sale classification. This was partially offset by a $264 million impairment at Maritza due to a reduction in expected cash flows after the expiration of the current PPA, and higher impairment expense of $62 million and $16 million at AES Clean Energy Development and AES Andes, respectively, due to the write-off of project development intangibles and capitalized development costs for projects that were determined to be no longer viable, including $51 million at AES Clean Energy Development due to the right sizing of our development company as part of the restructuring program initiated in February 2025.

See Note 23—*Asset Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Foreign currency transaction gains (losses)

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

Years Ended December 31,	2025	2024
Chile	$ (50)	$ (5)
Argentina	(29)	2
Corporate	(7)	33
Other	7	1
Total [(1)]	$ (79)	$ 31

(1) Includes losses of $26 million and gains of $137 million on foreign currency derivative contracts for the years ended December 31, 2025 and 2024, respectively.

The Company recognized net foreign currency transaction losses of $79 million in 2025, primarily driven by unrealized losses due to the depreciation of the Argentine peso, and unrealized losses in Chile due to the appreciation of the Chilean peso and the appreciation of the Colombian peso, which negatively impacted foreign currency forwards.

The Company recognized net foreign currency transaction gains of $31 million in 2024, primarily driven by realized gains on swaps and options denominated in the Brazilian real.

Other non-operating expense

Other non-operating expense was $113 million in 2025 due to a $103 million impairment of the Uplight equity method investment and convertible notes as a result of observable market factors; and a $10 million other-than-temporary impairment of convertible notes for 5B as a result of an observable price change from a transaction between 5B and a third party.

See Note 9—*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 benefit was $181 million in 2025 compared to income tax expense of $59 million in 2024. The Company's effective tax rates were (241)% and 7% for the years ended December 31, 2025 and 2024, respectively.

The 2025 effective tax rate was impacted by the current year benefits associated with ITCs and the reclassification of the Mong Duong asset group as held and used from held-for-sale, partially offset by the impacts of allocations of losses to tax equity investors on renewables projects. The 2024 effective tax rate was impacted by the prior year benefits associated with ITCs and the restructuring of a foreign holding company. These drivers were partially offset by the impacts of allocations of losses to tax equity investors on renewables projects. See Note 23—*Asset Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional information regarding the Mong Duong reclassification.

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 24—*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 increased $29 million to $55 million in 2025, compared to $26 million in 2024. This increase was primarily driven by lower earnings from sPower of $31 million, mainly due to lower contributions from renewables projects that came online.

See Note 9—*Investments In and Advances to Affiliates* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Loss from disposal of discontinued businesses

Net loss from disposal of discontinued businesses was $39 million in 2025, compared to $7 million in 2024, primarily related to alleged damages plus interest, as well as potential future damages, under a dispute related to representations and warranties in the 2016 share purchase agreement for Sul in the current year.

See Note 31—*Discontinued Operations* 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 loss attributable to noncontrolling interests and redeemable stock of subsidiaries decreased $129 million, or 15%, to $748 million in 2025, compared to $877 million in 2024. This decrease was primarily due to a decrease of $149 million at Mong Duong mostly driven by the derecognition of a valuation allowance on the loan receivable accounted for under ASC 310 upon reclassifying Mong Duong from held-for-sale to held and used, a decrease of $135 million at AES Clean Energy primarily attributable to lower allocation of losses to tax equity investors on projects placed in service and increased development services in the U.S., $34 million related to the sale of AES Brasil, $25 million related to improved operating results at Southland Energy after maintenance in the prior year, and $23 million related to the sell-down of AGIC. This was partially offset by an increase of $150 million at AES Indiana primarily attributable to higher allocation of losses to tax equity investors on BESS projects placed in service, $55 million due to day-one losses on the commencement of sales-type leases at AES Clean Energy Development, and $25 million related to acquisition of the remaining common shares in Cochrane.

Net income (loss) attributable to The AES Corporation

Net income attributable to The AES Corporation decreased $769 million, or 46%, to $910 million in 2025, compared to $1,679 million in 2024. This decrease was primarily due to:

- The prior year gain on sale of AES Brasil of $312 million;
- Lower margins from the Energy Infrastructure SBU of $271 million, excluding one-time restructuring costs, primarily due to higher prior year revenues from the monetization of the Warrior Run coal plant PPA and prior year net derivative gains as part of our commercial hedging strategy;
- Higher other expense of $211 million primarily related to day-one losses on commencement of sales-type leases and remeasurement of contingent consideration at AES Clean Energy Development;
- Higher impairments of $264 million at Maritza due to a reduction in expected cash flows after the expiration of the current PPA, partially offset by a $125 million prior-year impairment at Ventanas;
- Other non-operating expense of $113 million due to an impairment of the Uplight equity method investment and convertible notes, as well as an other-than-temporary impairment of convertible notes for 5B;
- Higher foreign currency translation losses of $102 million primarily related to unrealized losses due to the depreciation of the Argentine peso and unrealized losses in Chile due to the appreciation of the Chilean peso and the appreciation of the Colombian peso;
- Lower other income of $73 million primarily related to the prior year recognition of a bargain purchase gain on the Madison and Birdseye acquisition, a prior year gain corresponding to the step acquisition of Felix, and a prior year indexation adjustment of Stabilization Fund receivables at AES Andes;
- Lower interest income of $55 million primarily related to the sale of AES Brasil and prior year interest recognized on Stabilization Fund receivables in Chile; and
- One-time restructuring costs of $51 million.

These drivers were partially offset by:

- Higher income tax benefit of $257 million due to a lower effective tax rate, mainly driven by tax credit transfers;

- Higher margins from the Renewables SBU of $144 million, excluding one-time restructuring costs, primarily due to increases from new businesses and development services in the U.S., increased availability and lower spot prices on energy purchases in Colombia, and better hydrology in Colombia and Panama, partially offset by the negative impact of the sale of AES Brasil; and
- Derecognition of a valuation allowance on the loan receivable accounted for under ASC 310 upon reclassifying Mong Duong from held-for-sale to held and used of $127 million; and
- Higher margins from the Utilities SBU of $48 million, excluding one-time restructuring costs, primarily due to higher retail rates as a result of the AES Indiana 2024 Base Rate Order and AES Ohio 2024 DRC Settlement, higher transmission rates and rider revenues, and higher demand due to the impact of weather.

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 **New Energy Technologies** (investments in Fluence, Maximo, and other new and innovative energy technology businesses). Prior to the first quarter of 2025, our businesses in Chile were reported in the Energy Infrastructure SBU. After the sale or disconnection of a significant portion of AES Andes' coal plants and the expiration of its coal-indexed contracts with regulated customers at the end of 2024, the results of our businesses in Chile, excluding the two remaining coal plants, are now reported as part of the Renewables SBU.

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 2025, the Company updated the definitions of Adjusted EBITDA, Adjusted PTC, and Adjusted EPS to exclude costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts. These restructuring initiatives to streamline our organization and right-size our development company would result in significant incremental costs above normal operations, and the inclusion of such costs would result in a lack of comparability in our results of operations and could be misleading to investors. We believe excluding these costs associated with a major restructuring initiative better reflects the underlying business performance of the Company.

For the year ended December 31, 2024, the Company updated the definitions of EBITDA and Adjusted EBITDA to include accretion of AROs in the *depreciation and amortization* add-back. We believe excluding accretion of AROs from these metrics better reflects the underlying business performance of the Company and is aligned with the metrics of our industry peers. For comparability and consistency, all prior period EBITDA and Adjusted EBITDA measures have been recast to conform to the current presentation. The impact of this update resulted in an increase to Adjusted EBITDA of $22 million for the year ended December 31, 2024.

During the first quarter of 2024, the Company updated the definitions of Adjusted EBITDA, Adjusted PTC, and Adjusted EPS add-back (a) *unrealized gains or losses related to derivative transactions and equity securities* to include financial assets and liabilities measured using the fair value option, and updated add-back (e) *gains, losses, and costs due to the early retirement of debt* to include troubled debt restructuring. We believe excluding these gains or losses better reflects the underlying business performance of the Company. The Company also removed the adjustment for 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. As this adjustment was specific to certain contract terminations that occurred in 2020, we believe removing this adjustment from our non-GAAP definitions provides simplification and clarity for our investors. There were no such impacts in 2024.

EBITDA, Adjusted EBITDA, and Adjusted EBITDA with Tax Attributes

We define EBITDA as earnings before interest income and expense, taxes, depreciation, amortization, and accretion of AROs. We define Adjusted EBITDA as EBITDA adjusted for the impact of NCI and interest, taxes, depreciation, amortization, and accretion of AROs 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 pertaining to derivative transactions, equity securities, and financial assets and liabilities measured using the fair value option; (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 or troubled debt restructuring; and (f) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts.

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.

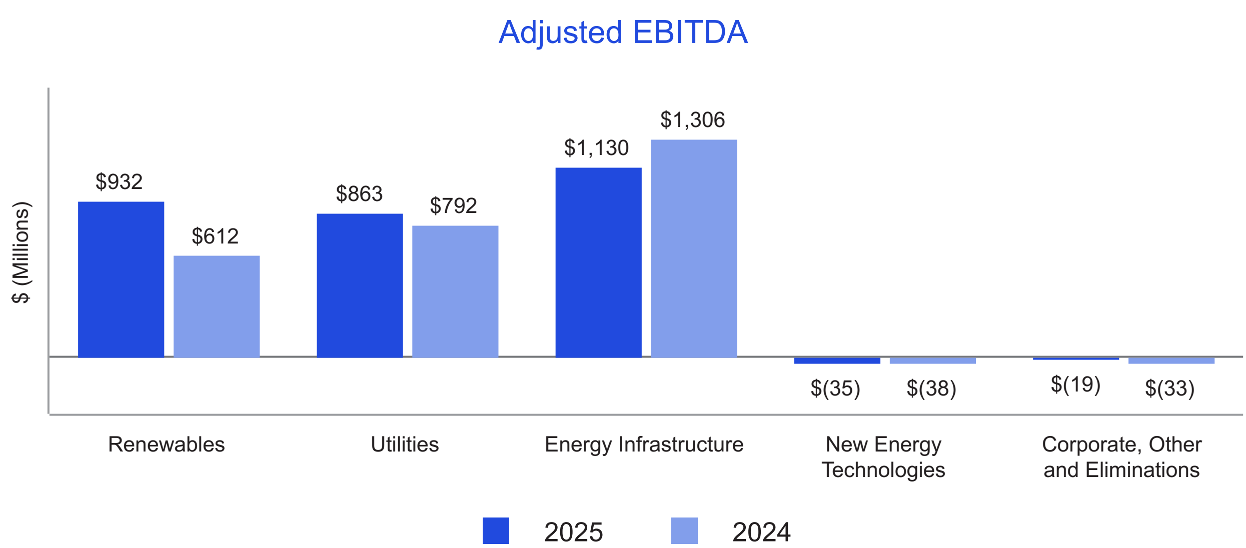
The GAAP measure most comparable to EBITDA, Adjusted EBITDA, and Adjusted EBITDA with Tax Attributes is *Net income*. We believe that EBITDA, Adjusted EBITDA, and Adjusted EBITDA with Tax Attributes better reflect the underlying business performance of the Company. Adjusted EBITDA is the most relevant 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 pertaining to derivative transactions, equity securities, or financial assets and liabilities remeasurement, unrealized foreign currency gains or losses, losses due to impairments, strategic decisions to dispose of or acquire business interests, retire debt, or implement restructuring initiatives, 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.

Reconciliation of Adjusted EBITDA and Adjusted EBITDA with Tax Attributes (in millions)	Years Ended December 31, 2025	2024
Net income	$ 162	$ 802
Income tax expense (benefit)	(181)	59
Interest expense	1,407	1,485
Interest income	(287)	(381)
Depreciation, amortization, and accretion of AROs	1,457	1,264
EBITDA	$ 2,558	$ 3,229
Less: Loss from disposal of discontinued businesses	39	7
Less: Adjustment for noncontrolling interests and redeemable stock of subsidiaries [1]	(824)	(734)
Less: Income tax expense (benefit), interest expense (income), and depreciation, amortization, and accretion of AROs from equity affiliates	171	136
Interest income recognized under service concession arrangements	58	65
Unrealized derivatives, equity securities, and financial assets and liabilities losses (gains)	120	(94)
Unrealized foreign currency losses	26	16
Disposition/acquisition losses (gains)	244	(323)
Impairment losses	369	280
Loss on extinguishment of debt and troubled debt restructuring	21	57
Restructuring costs	89	—
Adjusted EBITDA [1]	$ 2,871	$ 2,639
Tax attributes	1,540	1,313
Adjusted EBITDA with Tax Attributes [2]	$ 4,411	$ 3,952

(1) The allocation of earnings and losses to tax equity investors from both consolidated entities and equity affiliates is removed from Adjusted EBITDA. NCI also excludes amounts allocated to preferred shareholders during the construction phase before a project becomes operational, as this is akin to a financing arrangement.

(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 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

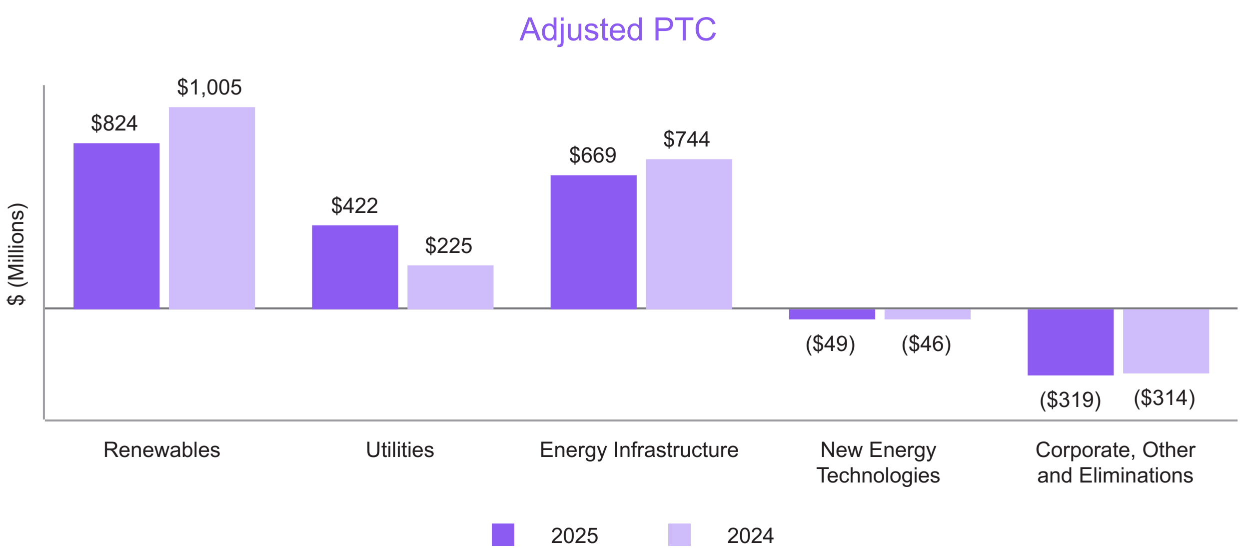
We define Adjusted PTC as pre-tax income from continuing operations attributable to The AES Corporation excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses pertaining to derivative transactions, equity securities, and financial assets and liabilities measured using the fair value option; (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 or troubled debt restructuring; and (f) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts. 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 a 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 pertaining to derivative transactions, equity securities, or financial assets and liabilities remeasurement, unrealized foreign currency gains or losses, losses due to impairments, and strategic decisions to dispose of or acquire business interests, retire debt, or implement restructuring initiatives, 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.

	Years Ended December 31,	
Reconciliation of Adjusted PTC (in millions)	**2025**	**2024**
Income from continuing operations, net of tax, attributable to The AES Corporation	$ 949	$ 1,686
Income tax expense (benefit) attributable to The AES Corporation	(276)	(19)
Pre-tax contribution	673	1,667
Unrealized derivatives, equity securities, and financial assets and liabilities losses (gains)	116	(94)
Unrealized foreign currency losses	26	16
Disposition/acquisition losses (gains)	244	(320)
Impairment losses	369	280
Loss on extinguishment of debt and troubled debt restructuring	30	65
Restructuring costs	89	—
Total Adjusted PTC	$ 1,547	$ 1,614



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 pertaining to derivative transactions, equity securities, and financial assets and liabilities measured using the fair value option; (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 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 or troubled debt restructuring; and (f) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts.

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 a relevant measure considered in the Company's internal evaluation of financial performance. Factors in this determination include the variability due to unrealized gains or losses pertaining to derivative transactions, equity securities, or financial assets and liabilities remeasurement, unrealized foreign currency gains or losses, losses due to impairments, and strategic decisions to dispose of or acquire business interests, retire debt, or implement restructuring initiatives, 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 diluted earnings per share of $1.31 for the year ended December 31, 2025. For purposes of measuring earnings per share under U.S. GAAP, income available to AES common stockholders is reduced by increases in the carrying amount of redeemable stock of subsidiaries to redemption value and increased by decreases in the carrying amount to the extent they represent recoveries of amounts previously reflected in the computation of earnings per share. While the adjustment for the year ended December 31, 2025 decreased earnings per share, it did not impact *Net income* on the Consolidated Statement of Operations. For purposes of computing Adjusted EPS, the Company excluded the adjustment to redemption value from the numerator. The table below reconciles the income available to AES common stockholders used in GAAP diluted earnings per share to the income from continuing operations used in calculating the non-GAAP measure of Adjusted EPS.

Reconciliation of Numerator Used for Adjusted EPS (in millions, except per share data)	Year Ended December 31, 2025 Income	Shares	$ per Share
GAAP DILUTED EARNINGS PER SHARE			
Income from continuing operations available to The AES Corporation common stockholders	$ 939	712	$ 1.31
Add back: Increase in redemption value of redeemable stock of subsidiaries	10	—	0.02
NON-GAAP DILUTED EARNINGS PER SHARE BEFORE EFFECT OF DILUTIVE SECURITIES	$ 949	712	$ 1.33
Restricted stock units	—	2	—
NON-GAAP DILUTED EARNINGS PER SHARE	$ 949	714	$ 1.33

Reconciliation of Adjusted EPS	Years Ended December 31, 2025		2024	
Diluted earnings per share from continuing operations	$ 1.33		$ 2.37	
Unrealized derivatives, equity securities, and financial assets and liabilities losses (gains)	0.17	(1)	(0.13)	(2)
Unrealized foreign currency losses	0.04		0.02	
Disposition/acquisition losses (gains)	0.34	(3)	(0.45)	(4)
Impairment losses	0.52	(5)	0.39	(6)
Loss on extinguishment of debt and troubled debt restructuring	0.04		0.09	(7)
Restructuring costs	0.12	(8)	—	
Less: Net income tax benefit	(0.22)	(9)	(0.15)	(10)
Adjusted EPS	$ 2.34		$ 2.14	

(1) Amount primarily relates to remeasurement of our investment in 5B of $48 million, or $0.07 per share, and net unrealized derivative losses at the Energy Infrastructure SBU of $41 million, or $0.06 per share.

(2) Amount primarily relates to unrealized gains on cross currency swaps in Brazil of $39 million, or $0.05 per share, unrealized gains on commodity derivatives at AES Clean Energy of $38 million, or $0.05 per share, and net unrealized derivative gains at the Energy Infrastructure SBU of $25 million, or $0.04 per share.

(3) Amount primarily relates to day-one losses on commencement of sales-type leases at AES Clean Energy Development of $166 million, or $0.23 per share, and AES Renewable Holdings of $13 million, or $0.02 per share, and losses on remeasurement of contingent consideration at AES Clean Energy of $66 million, or $0.09 per share; partially offset by gain on sale of Dominican Republic Renewables of $45 million, or $0.06 per share, and write-off of contingent consideration for a renewables development project at AES Andes of $10 million, or $0.01 per share.

(4) Amount primarily relates to gain on sale of AES Brasil of $312 million, or $0.44 per share, a gain on dilution of ownership in Uplight due to its acquisition of AutoGrid of $53 million, or $0.07 per share, and realized gains on cross currency swaps hedging the AES Brasil sale proceeds of $34 million, or $0.05 per share; partially offset by day-one losses at commencement of sales-type leases at AES Renewable Holdings of $63 million, or $0.09 per share, and loss on partial sale of our ownership interest in Amman East and IPP4 in Jordan of $10 million, or $0.01 per share.

(5) Amount primarily relates to impairments at Maritza of $264 million, or $0.37 per share, at Uplight of $103 million, or $0.14 per share, related to an impairment of the equity method investment and convertible notes, at AES Clean Energy Development projects of $80 million, or $0.11 per share, impairments at a renewables development project at AES Andes of $16 million, or $0.02 per share, and at Mong Duong of $9 million, or $0.01 per share; partially offset by the derecognition of the valuation allowance on a loan receivable accounted for under ASC 310 and the elimination of estimated costs to sell at Mong Duong of $127 million, or $0.18 per share, after reclassification to held and used.

(6) Amount primarily relates to impairments at Ventanas of $125 million, or $0.18 per share, at AES Clean Energy Development projects of $70 million, or $0.10 per share, at Brazil of $38 million, or $0.05 per share, and at Mong Duong of $32 million, or $0.04 per share.

(7) Amount primarily relates to losses incurred at AES Andes due to early retirement of debt of $29 million, or $0.04 per share, and costs incurred due to troubled debt restructuring at Puerto Rico of $20 million, or $0.03 per share.

(8) Amount relates to severance costs associated with the Company-wide restructuring program of $51 million, or $0.07 per share, and impairments at AES Clean Energy Development that were the result of the Company's restructuring program of $38 million, or $0.05 per share.

(9) Amount primarily relates to income tax benefits associated with the day-one losses on commencement of sales-type leases primarily at AES Clean Energy Development of $41 million, or $0.06 per share, valuation allowance related to Uplight impairment of the equity method investment and convertible notes of $39 million, or $0.05 per share, impairments at AES Clean Energy Development projects of $27 million, or $0.04 per share, remeasurement of contingent consideration at AES Clean Energy of $15 million, or $0.02 per share, impairments at Maritza of $12 million, or $0.02 per share, severance costs related to the Company's restructuring program of $10 million, or $0.01 per share, net unrealized derivative losses at AES Integrated Energy of $6 million, or $0.01 per share, and remeasurement of our investment in 5B of $4 million, or $0.01 per share; partially offset by income tax expense associated with the AES Ohio sell-down of $13 million, or $0.02 per share.

(10) Amount primarily relates to income tax benefits associated with the impairment and tax over book investment basis difference related to AES Ventanas of $68 million, or $0.09 per share, the sale of AES Brasil of $18 million, or $0.02 per share, the impairment at AES Clean Energy Development projects of $16 million, or $0.02 per share, and the day-one losses on commencement of sales-type leases at AES Renewable Holdings of $13 million, or $0.02 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,	2025	2024	$ Change	% Change
Operating Margin	$ 503	$ 399	$ 104	26%
Adjusted EBITDA [(1)]	932	612	320	52%
Adjusted EBITDA with Tax Attributes [(1)]	2,306	1,905	401	21%

(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 increased $104 million, primarily driven by $91 million due to development services in the U.S., $89 million from new businesses, $68 million in Colombia as a result of increased availability and lower spot prices on energy purchases, $60 million due to the results of AES Andes moving to Renewables in 2025, and $36 million due to higher generation in Panama as a result of better hydrological conditions during the first quarter of 2025. These increases were partially offset by a $177 million decrease due to the sale of AES Brasil in 2024, a $42 million decrease related to changes in mark-to-market of energy derivatives, a $38 million increase in fixed costs primarily related to an accelerated growth plan, and $15 million of one-time costs due to restructuring.

Adjusted EBITDA increased $320 million primarily due to the drivers mentioned above, adjusted for NCI, unrealized derivatives, restructuring costs, and depreciation, as well as higher Adjusted EBITDA from equity affiliates.

Adjusted EBITDA with Tax Attributes increased $401 million, primarily due to the increase in Adjusted EBITDA explained above, and higher tax attributes realized in the current year due to timing of tax attribute recognition, including higher income from tax credit transfers. During the years ended December 31, 2025 and 2024, we realized $1,374 million and $1,293 million, respectively, from tax attributes earned by our U.S. renewables business.

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,	2025	2024	$ Change	% Change
Operating Margin	$ 635	$ 543	$ 92	17 %
Adjusted EBITDA [(1)]	863	792	71	9 %
Adjusted EBITDA with Tax Attributes [(1)]	1,029	812	217	27 %
Adjusted PTC [(1)] [(2)]	422	225	197	88 %

(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 $92 million, primarily driven by $191 million due to higher retail rates as a result of the AES Indiana 2024 Base Rate Order and AES Ohio 2024 DRC Settlement, including the impact of certain riders now incorporated into base rates, higher transmission and rider revenues, and higher demand due to the impact of weather. These increases were partially offset by a $46 million increase in depreciation and amortization expense from additional assets placed in service, a $33 million increase in fixed costs mainly driven by higher property taxes due to higher assessed values, and a $14 million decrease due to the impact of planned outages.

Adjusted EBITDA increased $71 million primarily due to the drivers mentioned above, adjusted for NCI, depreciation and amortization, and restructuring costs.

Adjusted EBITDA with Tax Attributes increased $217 million mainly driven by a $146 million increase in realized tax attributes primarily related to the Pike County BESS and Petersburg Energy Center projects in the current year, as well as the increase in Adjusted EBITDA explained above.

Adjusted PTC increased $197 million primarily due to the drivers above, partially offset by higher depreciation and amortization 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,	2025	2024	$ Change	% Change
Operating Margin	$ 901	$ 1,233	$ (332)	-27%
Adjusted EBITDA [(1)]	1,130	1,306	(176)	-13%

(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 $332 million, primarily driven by $160 million higher prior year revenues from the monetization of the Warrior Run coal plant PPA, $108 million due to prior year unrealized and realized derivative gains, $60 million of prior year operating margin at AES Andes, which is reported in the Renewables SBU beginning in 2025, $23 million of lower LNG sales net of higher terminal fees, $18 million of one-time costs due to restructuring, and $17 million due to the prior year sell-down of Amman East and IPP4 in Jordan; partially offset by an increase of $49 million driven by higher availability due to lower maintenance in 2025.

Adjusted EBITDA decreased $176 million, primarily due to the drivers above, adjusted for unrealized derivatives and restructuring costs, as well as higher realized foreign currency gains; partially offset by the increase in ownership of Cochrane and higher equity earnings due to Gatun starting commercial operations.

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,	2025	2024	$ Change	% Change
Operating Margin	$ (11)	$ (7)	$ (4)	-57%
Adjusted EBITDA [(1)]	(35)	(38)	3	8%

(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 $4 million, with no material drivers.

Adjusted EBITDA increased $3 million, primarily due to a $23 million decrease in general and administrative expenses mainly related to lower business development costs, and lower losses from Uplight of $10 million after equity method accounting was suspended in the fourth quarter of 2025; partially offset by higher net losses from Fluence of $26 million mainly driven by a decline in sales, reflecting lower volumes fulfilled due to the timing of customer schedules.

Key Trends and Uncertainties

During 2026 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

— In April 2022, the U.S. Department of Commerce (“Commerce”) initiated an investigation into whether imports into the U.S. of solar cells and panels from Cambodia, Malaysia, Thailand, and Vietnam (“Southeast Asia”) were circumventing antidumping and countervailing duty (“AD/CVD”) orders on solar cells and panels from China. In August 2023, Commerce rendered final affirmative findings of circumvention with respect to all four countries, which resulted in the imposition of AD/CVD duties on certain imported cells and panels from Southeast Asia. Commerce’s determination and related matters remain the subject of ongoing litigation before the U.S. Court of International Trade ("CIT") and the U.S. Court of Appeals for the Federal Circuit.

In 2024, Commerce and the U.S. International Trade Commission (“ITC”) initiated new AD/CVD investigations on solar cells and panels imported from Southeast Asia. On April 18, 2025, Commerce rendered final affirmative determinations and AD/CVD rates with respect to all four countries. On June 13, 2025, the ITC issued its determination that imports from Malaysia and Vietnam have injured the U.S. industry and that imports from Cambodia and Thailand threaten injury. Commerce then issued orders on June 24, 2025, implementing the AD/CVD rates, which will be subject to annual review by Commerce. There is ongoing litigation about these and related matters in the CIT. We do not expect these AD/CVD orders will have a negative impact on our business.

Separately, the U.S. maintains a global safeguard tariff (currently 14% ad valorem) on solar cells and modules pursuant to the Section 201 Safeguard Action on crystalline silicon photovoltaic products, which became effective in February 2018. On June 21, 2024, President Biden issued Proclamation 10779, revoking the exclusion of bifacial panels from safeguard relief previously proclaimed in Proclamation 10339, and reinstating the tariff on bifacial panels under the Section 201 Safeguard Action, subject to certain qualifications. These global tariffs expired in February 2026.

The U.S. also maintains Section 301 tariffs on certain Chinese made lithium-ion batteries and related components utilized for energy storage systems, with such tariffs currently set at 25% effective January 1, 2026 (an increase from the previous rate of 7.5%). There are also ongoing AD/CVD investigations with respect to exports by China of natural and synthetic graphite used to make lithium-ion battery anode material. Final ITC and Commerce AD/CVD determinations in these investigations are expected in the first quarter of 2026 and could result in price increases.

Additionally, the Uyghur Forced Labor Prevention Act (“UFLPA”) seeks to block the import of products made with forced labor in certain areas of China, at any point in the supply chain, and may lead to certain suppliers being blocked from importing solar cells and panels into the U.S. While this has impacted the U.S. market, AES has managed this issue without significant impact to our projects. Further forced labor designations of entities under the UFLPA 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 Trump Administration has threatened or imposed tariffs on a wide range of countries and products. On February 10, 2025, President Trump signed Executive Orders modifying existing tariffs under Section 232 of the Trade Expansion Act of 1962 ("Section 232") on steel and aluminum imports to expand their scope and impose 25% tariffs on both products. The President raised these rates to 50% effective June 4, 2025. At this time, we do not expect the modifications to tariffs on steel and aluminum to have a material impact on our business.

On February 1, 2025, President Trump issued an Executive Order declaring a national emergency under the International Emergency Economic Powers Act (“IEEPA”) with respect to U.S. importation of fentanyl. The President imposed a 10% additional tariff on imports from China, effective February 4, 2025. Effective March 4, 2025, this tariff was increased to 20%.

On April 2, 2025, President Trump issued an Executive Order pursuant to IEEPA imposing an indefinite, baseline reciprocal 10% tariff on almost all goods imported into the U.S., effective April 5, 2025, and individualized higher IEEPA tariffs (11% to 50%) starting April 9, 2025 on goods originating from 57 countries with trade surpluses with the U.S. On April 9, 2025, the U.S. government issued a further Executive Order increasing the IEEPA reciprocal tariff on China to 125% effective April 10, 2025. Concurrently, the U.S. government announced a temporary suspension of the country-specific reciprocal tariff measures targeting most U.S. trading partners for a 90-day period, or until July 9, 2025, which was later extended until August 1, 2025. Effective May 14, 2025, the IEEPA reciprocal tariff rate applicable to China was lowered to 10%. IEEPA reciprocal tariffs, at various levels, have now gone into effect for most U.S. trading partners.

Several trading partners (including the EU, Japan, South Korea, and the UK) have reached bilateral trade agreements or frameworks with the U.S. The ultimate outcome of any reciprocal or other tariffs with countries that have not yet reached such trade agreements with the U.S. is uncertain. Also, in February 2026, on review of lower court decisions declaring the tariffs unlawful, the Supreme Court issued a decision holding that IEEPA does not authorize tariffs. However, President Trump subsequently stated that new tariffs would be issued under different statutory authority. The impact of these potential new tariffs on the Company is uncertain.

In July 2025, Commerce initiated a Section 232 investigation to determine the effects on national security of imports of polysilicon and its derivatives. In August 2025, Commerce initiated a separate investigation under Section 232 to determine the effects on national security of imports of wind turbines and their parts and components. These investigations are ongoing and their outcomes are uncertain.

In January 2026, the President issued a Proclamation under Section 232 concerning the importation of several critical minerals (including graphite and lithium) from any country. The Proclamation does not impose tariffs on the critical minerals but directs Commerce and the U.S. Trade Representative to negotiate agreements with foreign partners to secure reliable access to the critical minerals. An update on the outcome or status of these negotiations must be provided to the President within 180 days of the Proclamation. If the negotiations fail to result in agreements or to adequately address the identified risks, the President may consider trade-restrictive measures with respect to the critical minerals. The outcome of this process as well as its potential impact on the Company are uncertain.

We expect the tariffs on imports from China will increase overall costs for materials and parts that are imported to build and maintain renewable energy plants for the U.S. industry. However, AES has already shifted its supply chain outside of China for the vast majority of final products used to build and maintain renewable energy plants in the U.S. We expect limited impact to projects scheduled to become operational in 2026 through 2027 due to the announced tariffs on China.

The impact of new tariffs, reciprocal tariffs, or U.S. Government investigations or proclamations, the impact of any additional adverse Commerce determinations or other tariff disputes or litigation, the impact of the UFLPA, the potential future disruptions to the renewable energy supply chain and their effect on AES' U.S. 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 renewable energy projects. To that end, we have accelerated imports into the U.S. and increased our contracting for U.S. domestically manufactured solar panels, batteries, wind turbines, trackers, and other equipment, significantly mitigating the potential impacts from reciprocal tariffs or other tariffs.

For our U.S backlog of solar projects scheduled to finish construction and become operational in 2026 or 2027, we have contracted for most of our panel supply needs, with the majority of such panels being manufactured in the U.S. and most of the remaining panels having already been imported into the U.S. These remaining imports are expected to be largely insulated from AD/CVD measures and potential Section 232 outcomes, as they are expected to be manufactured using U.S. polysilicon. Imports will exclude modules from countries currently subject to AD/CVD orders or investigations.

Additionally, for our U.S. backlog of storage projects scheduled to finish construction and become operational in 2026 or 2027, we have contracted all our battery needs, with almost all of such batteries coming from U.S. or Korean suppliers. We have also completed contracting of U.S. domestically manufactured battery modules to support the remainder of our U.S. energy storage growth through 2027.

For our U.S. backlog of wind projects scheduled to be completed in 2026, we have contracted and received delivery of all turbines, and for our 2027 backlog of U.S. wind projects, we are fully contracted with U.S. suppliers and suppliers with primarily U.S. manufactured turbines.

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. Dry hydrological conditions in Panama, Colombia, and Chile can present challenges for our businesses in these markets. Low inflows can result in low reservoir levels, reduced generation output, and subsequently possible 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 an adverse impact on AES. As mitigation, AES has invested in thermal, wind, and solar generation assets, which have a complementary profile to hydroelectric plants. These plants are expected to have increased generation in low hydrology scenarios, offsetting possible impacts described from hydro assets.

La Niña conditions emerged towards the end of 2025 in the equatorial Pacific, following a period of ENSO-neutral conditions earlier in the year. According to the Climate Prediction Center ("CPC") and the International Research Institute for Climate and Society ("IRI"), La Niña began to dissipate in January 2026. Forecasts point to a transition back to ENSO-neutral conditions in early 2026 (through March 2026).

In Panama, total 2025 system inflows remained near historical averages, with the Bayano and Fortuna reservoirs however experiencing above-average levels due to abundant rainfall in the northern basins. These favorable conditions have supported strong hydroelectric generation, reduced reliance on thermal generation, and enabled potential surplus energy sales into the spot market. Furthermore, the commissioning of the Gatun combined cycle gas power plant by mid-2025 significantly reduced price and volatility, due to the displacement of other thermal generation. Additionally, the lower dispatch of natural gas-fired units due to favorable hydrology may create strategic opportunities for gas reallocation to international markets.

In Colombia, 2025 was the second wettest year on record. Reservoir levels remained elevated through Q4, with Chivor and other major reservoirs above seasonal norms. The favorable system hydrology throughout the year drove down spot prices compared to the prior year. Although, the fourth quarter saw a slight decline in rainfall and a moderate rise in spot prices, overall system storage remained robust.

In Chile, 2025 ranked as the fifth driest on record; however, it was marked by a structural decoupling of hydrology and the energy matrix. The power system demonstrated unprecedented resilience by offsetting the decline in hydroelectricity with record-breaking solar and wind generation, while leveraging the accelerated integration of BESS to mitigate curtailment, stabilize prices, and compensate for depleted system reservoirs.

The exact behavior pattern and strength of weather transitions (from/to La Niña or El Niño) is unknown 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 remain in line with historical averages, in some cases, market prices and generation above or below the average could present due to a variety of factors related to demand, market dynamics, or regulatory impacts. 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 2025. 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.

U.S. Tax Law Reform and U.S. Renewable Energy Tax Credits — On July 4, 2025, the U.S. enacted H.R. 1 (the “2025 Act”). The legislation significantly revised the laws governing U.S. renewable energy tax credits and the U.S. taxation of certain foreign earnings, which may impact our effective tax rate in future periods and could be material. In addition, the 2025 Act included amendments to, and extensions of, various other U.S. corporate income tax provisions including the determination of limitation on interest expense deductions. Any impact may change as U.S. Treasury and Internal Revenue Service (“IRS”) issue additional guidance, which may be material.

The U.S. Inflation Reduction Act of 2022 (the “IRA”) included provisions that benefited 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 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 value of the tax credit that benefits the tax equity investors at the time of its creation, which for projects utilizing the investment tax credit, begins in the quarter the renewables 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 2025 Act amends the phase out of wind and solar ITC and PTC tax credits. Wind and solar renewables projects that begin construction within 12 months of the enactment of the 2025 Act remain eligible for 100% of the credit without the 2027 placed-in-service deadline, provided that, under current Treasury guidance, the projects are placed in service no more than four calendar years after the calendar year when construction began. Wind and solar projects that begin construction after 12 months of the enactment must be placed in service no later than 2027. Wind and solar projects that began construction by the end of 2024 are not impacted by the 2025 Act. The 2025 Act does not impose tighter timelines for energy storage projects to qualify for the ITC and PTC, and it allows energy storage projects to receive the full ITC or PTC credit if they begin construction by 2033.

The 2025 Act also imposes a restriction precluding credits for renewables and storage projects claiming the ITC or PTC credit that start construction after December 31, 2025 and receive material assistance from a prohibited foreign entity, effectively limiting the percentage of total project costs that may be derived from products that are mined, produced or manufactured in China, with varying permissible percentages depending on the calendar year and applicable technology for the project. This restriction also precludes credit eligibility for taxpayers owning projects that start construction after December 31, 2024 that are classified as having ownership or certain other interests by a prohibited foreign entity, including projects over which a prohibited foreign entity is deemed to exercise formal or effective control.

Further, President Trump issued an Executive Order on July 7, 2025 that directed the Secretary of the Treasury to take action to enforce the provisions of the 2025 Act related to issuing updated guidance defining the start of construction for claiming the ITC and PTC and implementing the Foreign Entity of Concern (“FEOC”) Restrictions (the “Treasury Action”). The Executive Order also directed the Secretary of the Interior to take action to review its regulations, guidance, policies, and practices for any preferential treatment of wind and solar projects and eliminate those preferences within 45 days (the “Interior Action”).

On August 15, 2025, the Department of Treasury issued updated guidance defining the start of construction for purposes of claiming the ITC and PTC. AES does not expect the modifications to the start of construction guidance to materially impact its projects. The Department of Treasury has not yet issued comprehensive guidance implementing the FEOC restrictions, however. Further guidance, which may be material, is expected to be released within the coming months.

We expect the vast majority of our renewables project backlog to continue to qualify for the ITC and PTC. However, the Treasury Action may impose additional burdens in qualifying for the ITC and PTC.

In response to the Executive Order, the Department of Interior issued a memorandum requiring any “decisions, actions, consultations, and other undertakings” for wind or solar projects under Department of Interior jurisdiction to go through an additional three-phase approval process ending with approval from the Secretary of the Interior.

Our U.S. wind and solar projects are developed primarily on private land and are designed in a manner that minimizes the potential of a federal nexus. However, due to the broad language of the memorandum, there may be some impact to projects developed on private land.

In 2024, we realized $1,313 million of earnings from Tax Attributes, comprised of $1,293 million from the Renewables SBU and $20 million from the Utilities SBU. In 2025, we recognized $1,540 million of earnings from Tax Attributes, comprised of $1,374 million from the Renewables SBU and $166 million from the Utilities SBU.

The enactment of the 2025 Act requires that substantial guidance be published by the U.S. Department of Treasury and other government agencies. While we have taken significant measures to protect against the impact of changes under the 2025 Act to the IRA, including by implementing a program designed to ensure our backlog of U.S. renewables projects satisfy IRS safe harbor requirements for qualifying for the ITCs and PTCs, the impacts of the 2025 Act, the Treasury Action, the Interior Action or future actions that have the effect of modifying or repealing the ITCs and PTCs or adversely impacting renewable energy projects may be material to our results of operations.

Net CFC Tested Income (“NCTI”) — The 2025 Act amended the Global Intangible Low-Taxed Income (“GILTI”) provision by eliminating the reduction to foreign earnings subject to GILTI by an allowable economic return on investment beginning January 1, 2026. The GILTI provision was also renamed to the NCTI provision. Additionally, the 2025 Act modified the U.S. foreign tax credit provisions beginning January 1, 2026. Although the new NCTI rules provide for a reduced 14 percent effective tax rate on captured foreign income, by way of a 40 percent deduction, companies with a U.S. net operating loss or otherwise insufficient taxable income will not benefit from the lower effective tax rate and may not be able to utilize foreign tax credits. The new NCTI rules may subject a portion of our foreign earnings to current U.S. taxation in the future and could be material.

Limitation on Interest Expense Deductions — The 2025 Act retroactively amended the existing limitation on the deductibility of net interest expense beginning January 1, 2025. As amended, the deduction will be limited to interest income, plus 30% of tax basis EBITDA. Previously, the limitation was based on 30% of tax basis Earnings Before Interest and Taxes (“EBIT”). We expect the amendment to increase the current period permitted interest deductions and reduce the amount of disallowed interest expense subject to an indefinite carryforward. The limitation continues to be inapplicable to interest expense attributable to regulated utility property.

Global Tax — The macroeconomic and political environments in the U.S. and in some countries where our subsidiaries conduct business have changed in recent years. This could result in significant impacts to future tax law. In the U.S., the IRA included a 15% corporate alternative minimum tax (“CAMT”) based on adjusted financial statement income. In June 2025, the IRS began releasing interim guidance for CAMT and announced its intention to revise regulations that were proposed in September 2024. The impact to the Company in 2025 is not material. We will continue to monitor the issuance of CAMT revised guidance.

The Netherlands, Bulgaria, and Vietnam adopted legislation to implement Pillar 2 effective as of January 1, 2024. On January 5, 2026, the OECD published a side-by-side package to modify the Pillar 2 system in a manner that will fully exclude domestic and foreign profits of US-parented groups from Pillar 2's Undertaxed Profits Rule and Income Inclusion Rule. The side-by-side package is intended to take effect as of January 1, 2026, but is subject to enactment of legislation in the local jurisdictions. We will continue to monitor the issuance of legislation incorporating the side-by-side package, as well as other Pillar 2 amendments and new interpretive guidance in non-EU countries where the Company operates.

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 allow for recovery of O&M 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.

Argentina — In July 2024, the Argentine government enacted Law 27,742, known as Ley Bases, declaring a one-year public emergency in administrative, economic, financial, and energy matters. It grants the President delegated powers and initiates broad state reforms to deregulate the economy, including labor reform, the Incentive Regime for Large Investments, modifications to non-income tax measures, and the privatization of state-owned energy companies. Additionally, the Ministry of Energy issued Resolution 150/2024, repealing certain regulations from previous years that involved excessive state and CAMMESA intervention in the Wholesale Electricity Market ("MEM").

On January 28, 2025, the Energy Secretariat issued Resolution 21/2025 to reform the MEM and is intended to ensure secure energy supply and stable consumer costs.

On April 11, 2025, the Central Bank of Argentina started a new economic program supported by a $20 billion agreement with the International Monetary Fund. The key points of the program include (a) a removal of exchange restrictions for individuals and (b) foreign shareholders can distribute profits starting from 2025 and deadlines for foreign trade payments are relaxed.

On July 4, 2025, the Argentine government issued Decree 450/25, initiating a 24-month transition period to reform and deregulate the country's electricity market. The decree encourages free contracting between private entities and fosters competition in electricity generation and commercialization. Subsequently, on October 20, 2025, the Ministry of Economy and the Secretariat of Energy issued Resolution 400/25, which became effective on November 1, 2025, and provides a new framework introducing more competitive price signals, decentralizing fuel management, and reducing subsidies.

These 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.

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.

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. Despite the Title III protection, PREPA has been making substantially all of its payments to the generators in line with historical payment patterns.

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 Ilumina's non-recourse debt of $20 million continues to be in technical default and is classified as current as of December 31, 2025.

In 2022, a mediation commenced to resolve the PREPA Title III case. On March 19, 2025, the judge presiding over the case entered an order to permit the filing of an amended plan of adjustment and litigation of specific issues, including administrative expense claim by non-settling bondholders. The stay of plan confirmation and bondholder rights-related litigation was extended without a termination date, and the non-settling bondholders' motion to lift the stay was denied. The PROMESA Oversight Board filed an amended plan of adjustment and disclosure statement for PREPA on March 28, 2025. The mediation period was subsequently extended through April 1, 2026, reflecting the continuing efforts to resolve remaining matters under the Title III proceedings.

Considering the information available as of the date hereof, management believes the carrying amount of our long-lived assets in Puerto Rico of $80 million is recoverable as of December 31, 2025.

Impairments and Realizability

Long-lived Assets and Current Assets Held-for-Sale — During the year ended December 31, 2025, the Company recognized asset impairment expense of $224 million. See Note 23—*Asset Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information. As of December 31, 2025, 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 2025 was $109 million.

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.

Tax Asset Realizability — Certain AES Chilean businesses have recorded net deferred tax assets ("DTA") of $243 million relating primarily to net operating loss carryforwards, which are not subject to expiration. Their realization is dependent on generating sufficient taxable income. At this time, management believes it is more likely than not that all of the DTA will be realized; however, it could be reduced by way of valuation allowance in the near term if estimates of future taxable income are reduced.

Regulatory

FERC, RTOs, and Interconnection Prioritization — FERC approved one-time queue jumping proposals in PJM, MISO, and SPP over the course of the year. Limited additions to each RTO's queue are not expected to materially impact the projects already in our backlog; however, they could create uncertainty around network upgrade costs and the timing of integration of future projects in each RTO's queue. See Item 1A.—*Risk Factors — Our development projects are subject to substantial uncertainties* included in this Form 10-K for further details.

AES Ohio Legislation and Three-Year Rate Plan — On April 30, 2025, the Ohio legislature passed new energy legislation (House Bill 15) that was signed by the Governor and became effective August 14, 2025. The legislation allows Ohio's electric utilities to file three-year forecasted base distribution rate cases, which would replace electric security plans (ESPs) and associated recovery riders. AES Ohio currently anticipates that remaining recovery rider balances would be included in future base rates. Among other provisions, the legislation eliminates as of its effective date, the LGR, which previously allowed for recovery of net OVEC costs and revenues. Changes to the regulatory framework from this legislation, including the recovery of future net OVEC costs and revenues or remaining recovery rider balances, could be material to our results of operations, financial condition, and cash flows. To comply with House Bill 15, AES Ohio filed an application with the PUCO on November 10, 2025 to establish a Three-Year Rate Plan. This plan describes the investments necessary to strengthen and modernize AES Ohio's infrastructure and expand support for its customers. To enable these ongoing investments, the application also proposes rates for future electric distribution service in 2027, 2028, and 2029. The PUCO has set the evidentiary hearing to begin August 4, 2026, and a Commission Order is anticipated by the end of 2026.

AES Ohio ESP Appeal — From November 1, 2017 through December 18, 2019, AES Ohio operated pursuant to an approved ESP plan, which was initially approved on October 20, 2017 (ESP 3). On December 18, 2019, the PUCO approved AES Ohio's Notice of Withdrawal of ESP 3 and reversion to its prior rate plan (ESP 1). Among other items, the PUCO Order approving the ESP 1 rate plan included reinstating the non-bypassable RSC Rider, which provided annual revenue of approximately $79 million. The OCC has appealed to the Ohio Supreme Court the PUCO’s decision approving the reversion to ESP 1 as well as argued for a refund of the RSC revenue dating back to August 2021. Oral arguments regarding this appeal were held on April 22, 2025, and a court decision is pending.

AES Ohio Smart Grid Comprehensive Settlement — On October 23, 2020, AES Ohio entered into a Stipulation and Recommendation with the staff of the PUCO, various customers and organizations representing customers of AES Ohio and certain other parties with respect to, among other matters, AES Ohio's applications for (i) approval of AES Ohio's plan to modernize its distribution grid (Smart Grid Phase 1), (ii) findings that AES Ohio passed the SEET for 2018 and 2019, and (iii) findings that AES Ohio's ESP 1 satisfies the SEET and the more favorable in the aggregate (MFA) regulatory test. On June 16, 2021, the PUCO issued their opinion and order accepting the stipulation as filed. The OCC appealed the final PUCO order with respect to the 2018 and 2019 SEET to the Ohio Supreme Court on December 6, 2021. Oral arguments regarding this appeal were held on April 2, 2025. The Ohio Supreme Court reversed the PUCO's opinion and order with respect to the methodology used by the PUCO to support its findings related to the 2018 and 2019 SEET, and remanded the case to the PUCO to conduct further analysis of the SEET for those years. In the proceeding on remand, AES Ohio filed testimony proposing a refund of $1.6 million based on methodologies sponsored by its external financial consultant. The PUCO held an evidentiary hearing on this issue on October 28 and 29, 2025, and a PUCO decision is pending.

AES Indiana Rate Case Filing — On June 3, 2025, AES Indiana filed a petition with the IURC for authority to increase its basic rates and charges. On October 15, 2025, AES Indiana entered into a Stipulation and Settlement Agreement (the “Settlement Agreement”) with most parties in AES Indiana’s pending regulatory rate review at the IURC. This Settlement Agreement provides for updated base rates for electric services in AES Indiana’s territory and is subject, and conditioned upon, approval by the IURC. Among other things, the Settlement Agreement proposes an increase in AES Indiana’s revenue of $90.7 million and provides a return on common equity of 9.75% and cost of long-term debt of 5.34%, on a rate base of approximately $5.5 billion for AES Indiana’s 2027 electric service base rates. The partial Settlement Agreement also includes a commitment to not implement additional base rate increases, following the implementation of new base rates under the settlement, until at least January 2030 and to not start a second TDSIC Plan before January 2028. An evidentiary hearing with the IURC was held on January 28 and 29, 2026, and AES Indiana anticipates a final order from the IURC in the second quarter of 2026.

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 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 operations, and cash flows. As of December 31, 2025, the carrying value of our long-lived assets at Maritza is $64 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*.

Capital Resources and Liquidity

Overview

As of December 31, 2025, the Company had unrestricted cash and cash equivalents of $1.4 billion, of which $10 million was held at the Parent Company and qualified holding companies. The Company had restricted cash and debt service reserves of $780 million. The Company also had non-recourse and recourse aggregate principal amounts of debt outstanding of $23.2 billion and $6 billion, respectively. Of the $2.2 billion of our current non-recourse debt, $2.2 billion was presented as such because it is due in the next twelve months and $20 million relates to debt considered in default. This default is not a payment default but is instead a technical default triggered by failure to comply with covenants or other requirements contained in the non-recourse debt documents. See Note 12—*Obligations* in Item 8.—*Financial Statements* of this Form 10-K for additional detail. As of December 31, 2025, the Company also had $616 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 $879 million in recourse debt which matures within the next twelve months, including $79 million in outstanding borrowings under the commercial paper program. Furthermore, we have $391 million due under supplier financing arrangements that have a guarantee, $204 million guaranteed by the Parent Company and $187 million guaranteed by subsidiaries. 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 does not have any material unhedged exposure to variable interest rate debt. 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 $29.5 billion of total gross debt outstanding as of December 31, 2025, approximately $7.3 billion accrues interest at variable rates. 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, 2025, the total maximum outstanding amount of hedges protecting the company against current and expected variable rate exposure was $9.1 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 and performance-related guarantees or other credit support 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, 2025, 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 $3.8 billion in aggregate. This amount excludes arrangements that relate solely to the Company's own future performance, as well as those that are 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, 2025, we had $220 million in letters of credit under bilateral agreements, $117 million in letters of credit outstanding provided under our unsecured credit facilities, and $50 million in letters of credit outstanding provided under our revolving credit facilities. These letters of credit operate to guarantee performance relating to certain project development and construction activities and business operations.

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, 2025, the consolidated maximum undiscounted potential exposure to guarantees, letters of credit, and surety bonds issued by our subsidiaries was $4.7 billion, including $2.5 billion of guarantees and commitments, $2.1 billion of letters of credit outstanding, and $74 million of surety bonds.

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, 2025, the Company had approximately $119 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, 2026, or one year from the latest balance sheet date. Noncurrent receivables in the U.S. pertain to the sale of the Redondo Beach land. Noncurrent receivables in Chile pertain primarily to payment deferrals granted to mining customers as part of our green blend agreements. 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, 2025, the Company had an $862 million loan receivable related to the Mong Duong facility in Vietnam, which was constructed under a build, operate, and transfer 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. Of the loan receivable balance, $107 million was classified in *Other current assets* and $755 million was classified in *Loan receivable* on the Consolidated Balance Sheets. See Note 7—*Financing Receivables* and Note 21—*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, 2025 were debt financings, cash flows from operating activities, sales to noncontrolling interests, and purchases under supplier financing arrangements. The primary uses of cash in the year ended December 31, 2025 were repayments of debt, capital expenditures, repayments of obligations under supplier financing arrangements, and distributions to noncontrolling interests.

The primary sources of cash for the Company in the year ended December 31, 2024 were debt financings, cash flows from operating activities, purchases under supplier financing arrangements, sales to noncontrolling interests, and sales of short-term investments. The primary uses of cash in the year ended December 31, 2024 were repayments of debt, capital expenditures, repayments of obligations under supplier financing arrangements, and purchases of short-term investments.

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

	Year Ended December 31,	
Cash Sources:	2025	2024
Issuance of non-recourse debt	$ 5,866	$ 7,236
Net cash provided by operating activities	4,306	2,752
Borrowings under the revolving credit facilities	3,865	6,806
Sales to noncontrolling interests	2,084	1,247
Purchases under supplier financing arrangements	1,380	1,786
Issuance of preferred shares in subsidiaries	992	—
Issuance of recourse debt	800	1,450
Contributions from noncontrolling interests	437	222
Proceeds from the sale of business interests, net of cash and restricted cash sold	108	423
Sale of short-term investments	93	796
Other	297	97
Total Cash Sources	$ 20,228	$ 22,815
Cash Uses:		
Capital expenditures [1]	$ (5,929)	$ (7,392)
Repayments under the revolving credit facilities	(5,330)	(6,197)
Repayments of non-recourse debt	(3,817)	(4,306)
Repayments of obligations under supplier financing arrangements	(1,681)	(1,794)
Distributions to noncontrolling interests	(912)	(430)
Repayments of recourse debt	(898)	(200)
Dividends paid on AES common stock	(501)	(483)
Purchase of emissions allowances	(309)	(206)
Purchase of short-term investments	(185)	(818)
Payments for financing fees	(134)	(138)
Acquisitions of business interests, net of cash and restricted cash acquired	(108)	(246)
Other [2]	(301)	(556)
Total Cash Uses	$ (20,105)	$ (22,766)
Net increase in Cash, Cash Equivalents, and Restricted Cash	$ 123	$ 49

(1) Includes interest capitalized on development and construction of $502 million and $637 million for the years ended December 31, 2025 and 2024, respectively. Of the total capitalized in 2025 and 2024, $483 million and $577 million, respectively, are related to recourse and non-recourse debt interest payments. The remaining capitalized interest is primarily related to supplier financing arrangements.

(2) Includes the $27 million and $63 million effect of exchange rate changes on cash, cash equivalents and restricted cash for the years ended December 31, 2025 and 2024, respectively.

Consolidated Cash Flows

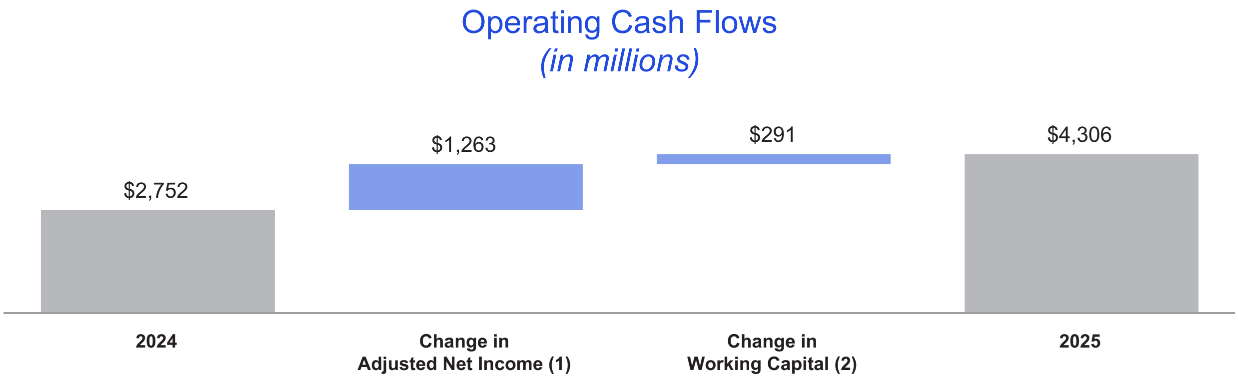
The following table reflects the changes in operating, investing, and financing cash flows for the comparative twelve-month periods (in millions):

	December 31,		
Cash flows provided by (used in):	2025	2024	$ Change
Operating activities	$ 4,306	$ 2,752	$ 1,554
Investing activities	(6,210)	(7,700)	1,490
Financing activities	1,975	4,963	(2,988)

Operating Activities

Fiscal Year 2025 versus 2024

Net cash provided by operating activities increased $1.6 billion for the year ended December 31, 2025, compared to December 31, 2024.



(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.

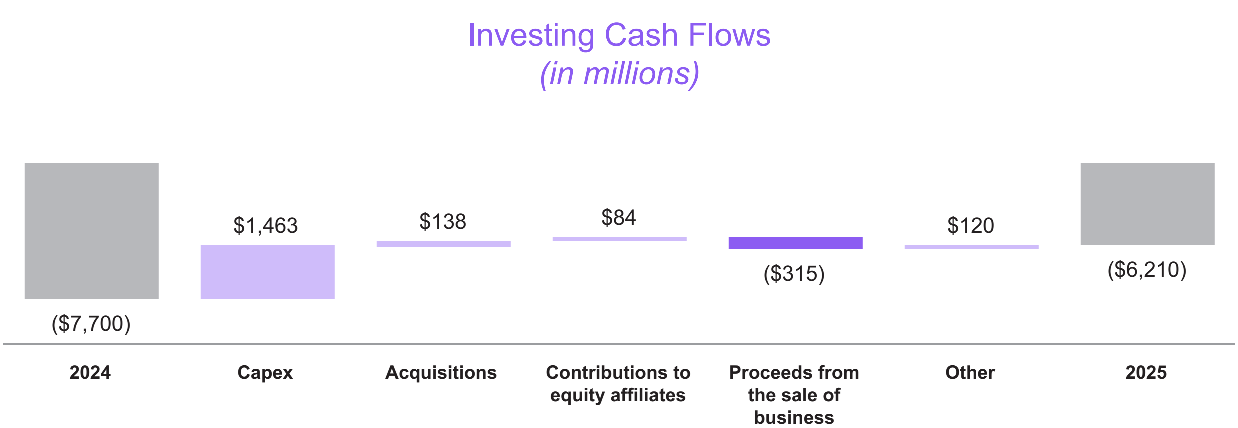
(2) The change in working capital is defined as the variance in total *changes in operating assets and liabilities* as shown on the Consolidated Statements of Cash Flows in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

- Adjusted net income increased $1.3 billion, primarily due to increased proceeds from the transfer of U.S. investment tax credits, and a decrease in cash paid for interest and income taxes, partially offset by lower margin at our Energy Infrastructure SBU.
- Change in working capital increased $291 million, primarily due to a decrease in accounts receivable due to the timing of collections and billings and an increase in contract liabilities related to development services in the U.S. These increases were partially offset by an increase in other current assets due to the timing of collection of tax credit transfer proceeds, the prior year sale of financing receivables under the Warrior Run PPA termination agreement, and an increase in inventory due to higher purchases and lower consumption.

Investing Activities

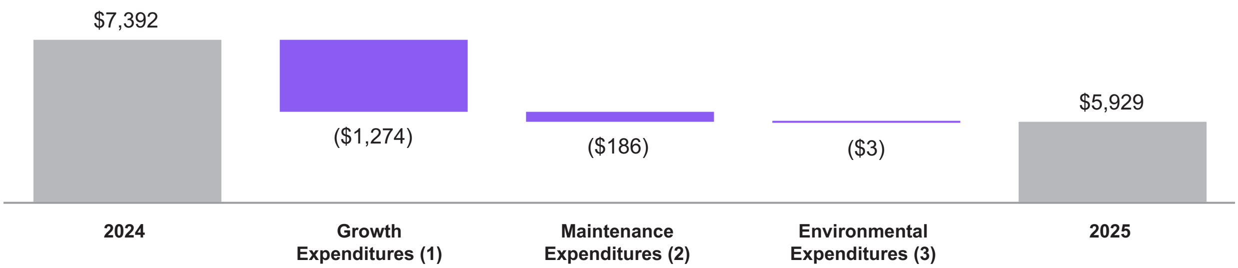
Fiscal Year 2025 versus 2024

Net cash used in investing activities decreased $1.5 billion for the year ended December 31, 2025 compared to December 31, 2024.



- Cash paid for acquisitions of business interests decreased $138 million, primarily due to the prior year acquisition of Atacama Solar in Chile for $105 million, higher net acquisitions in the prior year of $64 million for various businesses at AES Clean Energy Development, and the prior year acquisition of Hoosier Wind for $49 million; partially offset by the current year acquisition of Crossvine for $78 million.
- Contributions to equity affiliates decreased $84 million, primarily driven by the prior year contributions to Gatun and sPower for $64 million and $22 million, respectively.
- Cash proceeds from sales of business interests decreased $315 million, primarily due to proceeds of $412 million, net of transaction costs and cash sold, from the sale of AES Brasil in the prior year; partially offset by the current year sell-down of Dominican Republic Renewables for $103 million.
- Capital expenditures decreased $1.5 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.

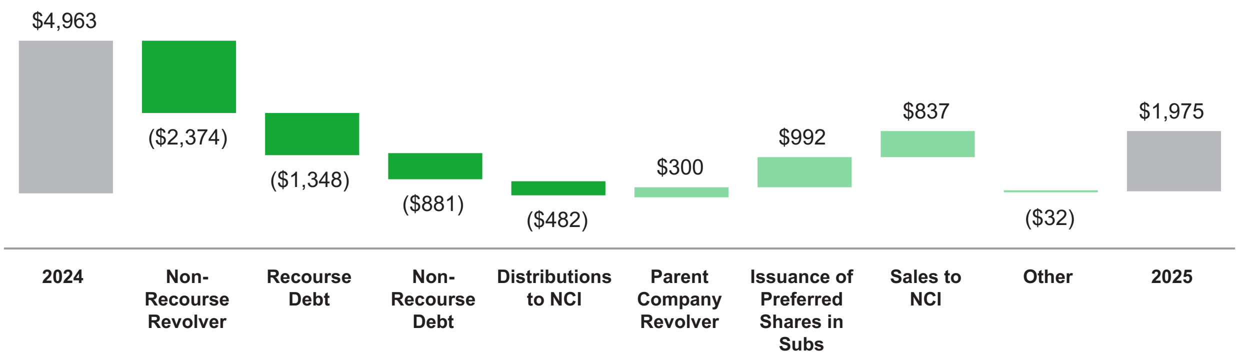
- Growth expenditures decreased $1.3 billion, primarily driven by a decrease in expenditures for U.S. and Dominican Republic renewables as well as transmission and distribution project investments at our U.S. utilities compared to the prior year; partially offset by an increase in expenditures for renewables projects in Chile in the current year.
- Maintenance expenditures decreased $186 million, primarily driven by a $69 million decrease due to timing of maintenance at Southland, AES Ohio, and TermoAndes, and a $61 million decrease due to the sale of AES Brasil in October 2024.
- Environmental expenditures decreased $3 million, with no material drivers.

Financing Activities

Fiscal Year 2025 versus 2024

Net cash provided by financing activities decreased $3 billion for the year ended December 31, 2025 compared to December 31, 2024.

Financing Cash Flows
(in millions)



See Notes 12—*Obligations*, 17—*Redeemable stock of subsidiaries,* and 18—*Equity* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for more information regarding significant transactions.

- The $2.4 billion impact from non-course revolvers is primarily due to $1.4 billion of net repayments in the current year and $751 million net borrowings in the prior year at the Renewables SBU, and $247 million of net repayments in the current year and $69 million of net borrowings in the prior year at the Utilities SBU; partially offset by $122 million of higher net repayments at the Energy Infrastructure SBU in the prior year.
- The $1.3 billion impact from recourse debt is primarily due to the issuance of $1.5 billion subordinated notes at the Parent Company in the prior year and repayments of $898 million at the Parent Company in the current year, partially offset by current year issuance of $800 million of senior notes and repayments of $200 million in the prior year.
- The $881 million impact from non-recourse debt transactions is primarily due to $963 million lower net borrowings at the Utilities SBU and $451 increase in net repayments at the Energy Infrastructure SBU, partially offset by a $533 increase in net borrowings at the Renewables SBU.
- The $482 million impact from distributions to noncontrolling interests is primarily related to increases of $307 million and $191 million at AES Clean Energy and AES Indiana, respectively, mainly due to higher proceeds from the transfer of U.S. investment tax credits distributed to tax equity partners.
- The $300 million impact from the Parent Company revolver is due to higher net borrowings in the current year.
- The $992 million impact from issuance of preferred shares in subsidiaries is primarily due to the proceeds received from the issuance of preferred shares in AES Global Insurance, Bellefield 2 Equity Holdings, AES DevCo HoldCo, Desarrollos Renovables, and the Bolero BESS project.
- The $837 million impact from sales to noncontrolling interests is primarily due to $540 million from the sale of ownership interest in AES Ohio and increase in proceeds of $328 million and $207 million at AES Clean Energy Development and AES Indiana, respectively, due to higher sales of ownership in project companies to tax equity investors; partially offset by a $104 million decrease in sales under the Chile Renewables partnership with GIP, a decrease of $103 million in proceeds at AES Renewable Holdings due to higher sales of ownership in project companies to tax equity investors in the prior year, and $35 million related to the prior year sale of ownership interest in the Marahu project.

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 facilities and commercial paper program; and proceeds from asset sales. The Parent Company credit facilities 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 facilities 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, 2025	December 31, 2024
Consolidated cash and cash equivalents	$ 1,382	$ 1,524
Less: Cash and cash equivalents at subsidiaries	(1,372)	(1,259)
Parent Company and qualified holding companies' cash and cash equivalents	10	265
Commitments under the Parent Company credit facilities	1,800	1,800
Less: Letters of credit under the credit facilities	(50)	(18)
Less: Borrowings under the credit facility	(300)	—
Less: Borrowings under the commercial paper program	(79)	—
Borrowings available under the Parent Company credit facilities	1,371	1,782
Total Parent Company Liquidity	$ 1,381	$ 2,047

The Parent Company paid dividends of $0.70 per outstanding share to its common stockholders during the year ended December 31, 2025. 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 $6.0 billion and $5.7 billion as of December 31, 2025 and 2024, respectively. See Note 12—*Obligations* 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 facilities 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 facilities 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, 2025, 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 facilities 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 $2.2 billion. The portion of current debt related to such defaults was $20 million at December 31, 2025, all of which was non-recourse debt related to AES Ilumina. This default is not a payment default, but is instead a technical default triggered by failure to comply with other covenants or other conditions contained in the non-recourse debt documents. See Note 12—*Obligations* 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, 2025, 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, 2025, 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, 2025 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]	$ 29,549	$ 3,100	$ 7,172	$ 7,338	$ 11,939	$ —	12
Interest payments on long-term debt [3]	16,095	1,425	2,526	2,071	10,073	—	N/A
Supplier financing arrangements	616	616	—	—	—	—	12
Finance lease obligations [2]	1,714	36	77	83	1,518	—	15
Operating lease obligations [2]	843	50	74	66	653	—	15
Electricity obligations	8,356	819	1,360	1,271	4,906	—	13
Fuel obligations	7,490	1,374	1,555	1,240	3,321	—	13
Other purchase obligations	7,644	4,282	1,722	743	897	—	13
Other long-term liabilities reflected on AES' consolidated balance sheet under GAAP [2] [4]	1,451	—	739	103	592	17	N/A
Total	$ 73,758	$ 11,702	$15,225	$12,915	$ 33,899	$ 17	

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(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 obligations category.
(2) Excludes any businesses classified as held-for-sale. See Note 25—*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, 2025 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, 2025.
(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 11—*Regulatory Assets and Liabilities*), (2) contingencies (See Note 14—*Contingencies*), (3) pension and other postretirement employee benefit liabilities (see Note 16—*Benefit Plans*), (4) derivatives and incentive compensation (See Note 6—*Derivative Instruments and Hedging Activities*) or (5) any taxes (See Note 24—*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 consolidated contingent contractual obligations as of December 31, 2025:

Parent Company Contingent Contractual Obligations	Maximum Exposure (in millions)	Number of Agreements	Maximum Exposure Range for Each Agreement (in millions)
Guarantees and commitments [1]	$ 3,774	24	< $1 — 1,117
Letters of credit under bilateral agreements	220	8	< $1— 92
Letters of credit under the unsecured credit facilities	117	7	< $1 — 60
Letters of credit under the revolving credit facilities	50	17	< $1 — 38
Total	$ 4,161	56	

(1) Excludes payment obligation and commercial transaction arrangements entered into by the Parent Company on behalf of its consolidated subsidiaries, which relate to the Company's own future performance. See Schedule I—*Condensed Financial Information of Registrant* for additional information on guarantees issued by the Parent Company.

Additionally, some of the Company's subsidiaries have contingent contractual obligations that are non-recourse to the Parent Company. The following table presents our subsidiaries' consolidated contingent contractual obligations as of December 31, 2025:

Subsidiary Contingent Contractual Obligations	Maximum Exposure (in millions)	Number of Agreements	Maximum Exposure Range for Each Agreement (in millions)
Guarantees and commitments	$ 2,532	40	< $1 — 490
Letters of credit under subsidiary credit facilities	2,114	351	< $1 — 97
Surety bonds	74	108	< $1 — 10
Total	$ 4,720	499	

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 2025, 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 10—*Goodwill and Other Intangible Assets* and Note 23—*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.

Hypothetical Liquidation at Book Value — 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.

Many of 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 were 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 renewables 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.

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* and Note 8—*Allowance for Credit Losses* 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 2025 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, therefore, proactively manage, market risk. Market risk is a 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 associated primarily with outstanding and expected issuances and borrowings, and foreign currency exchange rates associated primarily with investments in foreign subsidiaries and affiliates. To hedge our exposure to market risks, we enter into various transactions, including derivatives.

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 2025 Form 10-K.

Commodity Price Risk

AES generally seeks to hedge its exposure to commodity price risk; however, certain generation businesses may retain limited unhedged positions due to short-term sales structures or contractual mismatches between supply and obligations. As a result, a portion of operating results may be exposed to changes in market prices for electricity, fuels, and environmental credits. Increased competition, including from renewable generation and the growing penetration of energy storage systems, may exert downward pressure on electricity prices in certain markets. AES employs risk management strategies designed to limit the impact of commodity price movements on consolidated financial performance. These strategies may include the use of physical and financial commodity contracts, futures, swaps, and options. The portfolio also benefits from natural offsets across businesses, as changes in commodity prices may positively affect certain operations while negatively affecting others. Actual results may differ from modeled sensitivities due to local market conditions, including hydrology, regional supply and demand dynamics, fuel supply constraints, competition and bidding conditions, 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, 2025, a hypothetical 10% increase in commodity prices would not be expected to have a material impact on consolidated pre-tax earnings, with estimated impacts of less than a $10 million gain for power, less than a $10 million gain for gas, and less than a $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 exclude 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.

Commodity price exposure at individual businesses may change over time as contracts mature and hedging positions are adjusted, and although longer-dated forward commodity prices are generally less volatile, our sensitivity to changes in commodity prices may increase in later years due to lower levels of forward hedging 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. This type of market risk exists primarily in California, Chile, the Dominican Republic, and Panama.

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 2025 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 2027.

Our thermal assets in Panama have PPAs with distribution companies which match 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. 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

AES operates in multiple countries and as such is 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 operational 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, 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 in our 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 exposure to the Argentine peso, which could increase earnings volatility, particularly in times of adverse exchange-rate movement. Additionally, as of December 31, 2025, a hypothetical one-time 10% appreciation of the U.S. dollar applied to forecasted 2026 cash distributions, net of outstanding hedges and with all other variables held constant, indicates that cash distributions attributable to foreign subsidiaries in the Colombian peso, Euro, and Argentine peso may each be exposed to exchange-rate movements resulting in less than a $5 million loss.

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

AES is 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, 2025, a hypothetical 100-basis-point increase in interest rates would be expected to increase annual pre-tax interest expense by less than $10 million, based on the portion of the Company's debt that is subject to variable interest rates. These amounts represent full-year 2026 exposure and do not take into account the historical correlation among 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, 2025, and 2024, 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, 2025, and the related notes and 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, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, 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, 2025, 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 March 2, 2026 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 Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter 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 matter below, providing a separate opinion on the critical audit matter or on the account or disclosure to which it relates.

Allocation of Earnings to Noncontrolling Interests in Tax Equity Partnerships

Description of the Matter	As described in Notes 1 and 18, certain renewables projects have been financed with tax equity structures, where tax equity investors receive a noncontrolling interest in consolidated partnerships where the allocation of the economic attributes, including tax attributes vary over the life of the project. When the allocation of the partnership's 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 the noncontrolling interests for these consolidated partnerships, when it is a reasonable approximation of the profit-sharing arrangement. The Company recorded $748 million of net loss attributable to noncontrolling interests and redeemable stock of subsidiaries on the consolidated statements of operations in 2025, the majority of which was allocated using the HLBV method. Auditing the allocation of earnings and losses to noncontrolling interest holders using HLBV for partnerships related to renewable projects that were placed into service during the period was complex due to the evaluation of whether a newly established HLBV calculation used to allocate earnings appropriately reflects the unique substantive profit-sharing terms and features within each partnership agreement. A greater extent of audit effort and specialized skill and knowledge was required to evaluate the contractual provisions in each partnership agreement as well as the appropriateness of the investors' claim to the net equity of the partnership used in the HLBV method.
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 calculations for partnership agreements related to renewable projects that were placed into service during the period. For example, we tested management's review of substantive profit-sharing terms to evaluate whether they are properly reflected in the HLBV calculations. To test the allocation of earnings and losses to noncontrolling interest holders for partnership agreements related to certain renewable projects that were placed into service during the period, we read the related partnership agreements to understand the substantive profit-sharing provisions. We evaluated the HLBV calculations for consistency with the contractual provisions in the related partnership agreements and tested the capital transactions of the tax equity investors. We involved tax subject matter professionals to assist in evaluating the calculation of the investors' net equity accounts used in the HLBV method, 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 method 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

March 2, 2026

Consolidated Balance Sheets
December 31, 2025 and 2024

	2025	2024
	(in millions, except share and per share data)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,382	$ 1,524
Restricted cash	691	437
Short-term investments	174	79
Accounts receivable, net of allowance of $39 and $52, respectively	1,683	1,646
Inventory	612	593
Prepaid expenses	192	157
Other current assets, net of allowance of $2 and $0, respectively	1,723	1,533
Current held-for-sale assets	45	862
Total current assets	6,502	6,831
NONCURRENT ASSETS		
Property, plant, and equipment, net of accumulated depreciation of $9,796 and $8,701, respectively	37,818	33,166
Investments in and advances to affiliates	1,004	1,124
Debt service reserves and other deposits	89	78
Goodwill	342	345
Other intangible assets, net of accumulated amortization of $479 and $426, respectively	2,040	1,947
Deferred income taxes	397	365
Loan receivable, net of allowance of $19 and $0, respectively	755	—
Other noncurrent assets, net of allowance of $24 and $20, respectively	2,821	2,917
Noncurrent held-for-sale assets	—	633
Total noncurrent assets	45,266	40,575
TOTAL ASSETS	$ 51,768	$ 47,406
LIABILITIES, REDEEMABLE STOCK OF SUBSIDIARIES, AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 1,980	$ 1,654
Accrued interest	268	256
Accrued non-income taxes	294	249
Supplier financing arrangements	616	917
Accrued and other liabilities	2,223	1,246
Recourse debt	879	899
Non-recourse debt	2,232	2,688
Current held-for-sale liabilities	—	662
Total current liabilities	8,492	8,571
NONCURRENT LIABILITIES		
Recourse debt	5,105	4,805
Non-recourse debt	21,681	20,626
Deferred income taxes	1,581	1,490
Other noncurrent liabilities	2,980	2,881
Noncurrent held-for-sale liabilities	—	391
Total noncurrent liabilities	31,347	30,193
Commitments and Contingencies (see Notes 13 and 14)		
Redeemable stock of subsidiaries	2,824	938
EQUITY		
THE AES CORPORATION STOCKHOLDERS' EQUITY		
Common stock ($0.01 par value, 1,200,000,000 shares authorized; 859,836,539 issued and 712,201,777 outstanding at December 31, 2025 and 859,709,987 issued and 711,074,269 outstanding at December 31, 2024)	9	9
Additional paid-in capital	5,904	5,913
Retained earnings	641	293
Accumulated other comprehensive loss	(698)	(766)
Treasury stock, at cost (147,634,762 and 148,635,718 shares, respectively)	(1,793)	(1,805)
Total AES Corporation stockholders' equity	4,063	3,644
NONCONTROLLING INTERESTS	5,042	4,060
Total equity	9,105	7,704
TOTAL LIABILITIES, REDEEMABLE STOCK OF SUBSIDIARIES, AND EQUITY	$ 51,768	$ 47,406

See Accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Operations
Years ended December 31, 2025, 2024, and 2023

	2025	2024	2023
	(in millions, except per share amounts)		
Revenue:			
Non-Regulated	$ 8,195	$ 8,756	$ 9,245
Regulated	4,038	3,522	3,423
Total revenue	12,233	12,278	12,668
Cost of Sales:			
Non-Regulated	(6,603)	(6,985)	(7,173)
Regulated	(3,419)	(2,979)	(2,991)
Total cost of sales	(10,022)	(9,964)	(10,164)
Operating margin	2,211	2,314	2,504
General and administrative expenses	(241)	(288)	(255)
Interest expense	(1,407)	(1,485)	(1,319)
Interest income	287	381	551
Loss on extinguishment of debt	(26)	(17)	(63)
Other expense	(458)	(175)	(99)
Other income	67	156	89
Gain on disposal and sale of business interests	58	351	134
Goodwill impairment expense	—	—	(12)
Asset impairment expense	(224)	(374)	(1,067)
Foreign currency transaction gains (losses)	(79)	31	(359)
Other non-operating expense	(113)	—	—
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES AND EQUITY IN EARNINGS OF AFFILIATES	75	894	104
Income tax benefit (expense)	181	(59)	(261)
Net equity in losses of affiliates	(55)	(26)	(32)
INCOME (LOSS) FROM CONTINUING OPERATIONS	201	809	(189)
Gain (loss) from disposal of discontinued businesses, net of income tax benefit (expense) of $0, $(7), and $7, respectively	(39)	(7)	7
NET INCOME (LOSS)	162	802	(182)
Less: Net loss attributable to noncontrolling interests and redeemable stock of subsidiaries	748	877	431
NET INCOME ATTRIBUTABLE TO THE AES CORPORATION	$ 910	$ 1,679	$ 249
Increase in redemption value of redeemable stock of subsidiaries	(10)	—	—
NET INCOME AVAILABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ 900	$ 1,679	$ 249
AMOUNTS AVAILABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:			
Income from continuing operations available to The AES Corporation common stockholders	$ 939	$ 1,686	$ 242
Income (loss) from discontinued operations available to The AES Corporation common stockholders	(39)	(7)	7
NET INCOME AVAILABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ 900	$ 1,679	$ 249
BASIC EARNINGS PER SHARE:			
Income from continuing operations available to The AES Corporation common stockholders	$ 1.31	$ 2.39	$ 0.36
Income (loss) from discontinued operations available to The AES Corporation common stockholders	(0.05)	(0.01)	0.01
NET INCOME AVAILABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ 1.26	$ 2.38	$ 0.37
DILUTED EARNINGS PER SHARE:			
Income from continuing operations available to The AES Corporation common stockholders	$ 1.31	$ 2.37	$ 0.34
Income (loss) from discontinued operations available to The AES Corporation common stockholders	(0.05)	(0.01)	0.01
NET INCOME AVAILABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ 1.26	$ 2.36	$ 0.35

See Accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income (Loss)

Years ended December 31, 2025, 2024, and 2023

	2025	2024	2023
		(in millions)	
NET INCOME (LOSS)	$ 162	$ 802	$ (182)
Foreign currency translation activity:			
Foreign currency translation adjustments, net of income tax expense of $1, $0, and $0, respectively	115	(236)	146
Reclassification to earnings, net of $0 income tax for all periods	—	649	—
Total foreign currency translation adjustments	115	413	146
Derivative activity:			
Change in fair value of derivatives, net of income tax benefit (expense) of $3, $(98), and $3, respectively	(48)	463	(1)
Reclassification to earnings, net of income tax benefit (expense) of $11, $(8), and $(9), respectively	2	30	(73)
Total change in fair value of derivatives	(46)	493	(74)
Pension activity:			
Change in pension adjustments due to prior service cost, net of $0 income tax for all periods	1	—	1
Change in pension adjustments due to net actuarial loss for the period, net of income tax benefit of $0, $2, and $0, respectively	(1)	(5)	(4)
Reclassification to earnings, net of income tax expense of $0, $1, and $0, respectively	1	15	—
Total pension adjustments	1	10	(3)
Fair value option liabilities activity:			
Change in fair value option liabilities due to instrument-specific credit risk, net of $0 income tax for all periods	—	3	—
Total change in fair value option liabilities	—	3	—
OTHER COMPREHENSIVE INCOME	70	919	69
COMPREHENSIVE INCOME (LOSS)	232	1,721	(113)
Less: Comprehensive loss attributable to noncontrolling interests and redeemable stock of subsidiaries	755	208	498
COMPREHENSIVE INCOME ATTRIBUTABLE TO THE AES CORPORATION	$ 987	$ 1,929	$ 385

See Accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Changes in Equity

Years ended December 31, 2025, 2024, and 2023

	THE AES CORPORATION STOCKHOLDERS									
	Preferred Stock		Common Stock		Treasury Stock		Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Loss	Noncontrolling Interests [1]
(in millions)	Shares	Amount	Shares	Amount	Shares	Amount				
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)
Foreign currency translation adjustments and reclassification to earnings, net of income tax	—	—	—	—	—	—	—	—	136	9
Change in fair value of derivatives and reclassification to earnings, net of income tax	—	—	—	—	—	—	—	—	3	(77)
Change in pension adjustments and reclassification to earnings, 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
Net income (loss)	—	—	—	—	—	—	—	1,679	—	(791)
Foreign currency translation adjustments and reclassification to earnings, net of income tax	—	—	—	—	—	—	—	—	(88)	502
Change in fair value of derivatives and reclassification to earnings, net of income tax	—	—	—	—	—	—	—	—	333	86
Change in pension adjustments and reclassification to earnings, net of income tax	—	—	—	—	—	—	—	—	2	8
Change in fair value option liabilities, net of income tax	—	—	—	—	—	—	—	—	3	—
Total other comprehensive income (loss)	—	—	—	—	—	—	—	—	250	596
Reclassification of redeemable stock of subsidiaries to noncontrolling interests [2]	—	—	—	—	—	—	—	—	—	736
Disposition of business interests	—	—	—	—	—	—	14	—	—	(1,399)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	—	(368)
Acquisitions of noncontrolling interests	—	—	—	—	—	—	(802)	—	498	304
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	—	411
Sales to noncontrolling interests	—	—	—	—	—	—	(19)	—	—	1,074
Conversion of Corporate Units to shares of common stock	(1.0)	(838)	40.5	1	—	—	838	—	—	—
Dividends declared on AES common stock ($0.6935/share)	—	—	—	—	—	—	(493)	—	—	—
Purchase of treasury stock	—	—	—	—	0.1	(3)	3	—	—	—
Issuance and exercise of stock-based compensation benefit plans, net of income tax	—	—	0.1	—	(0.9)	11	17	—	—	—
Balance at December 31, 2024	—	$ —	859.7	$ 9	148.6	$(1,805)	$ 5,913	$ 293	$ (766)	$ 4,060
Net income (loss)	—	—	—	—	—	—	—	910	—	(590)
Foreign currency translation adjustments and reclassification to earnings, net of income tax	—	—	—	—	—	—	—	—	114	1
Change in fair value of derivatives and reclassification to earnings, net of income tax	—	—	—	—	—	—	—	—	(37)	(8)
Total other comprehensive income (loss)	—	—	—	—	—	—	—	—	77	(7)
Adjustments to redemption value of redeemable stock of subsidiaries	—	—	—	—	—	—	—	(10)	—	—
Reclassification of redeemable stock of subsidiaries to noncontrolling interests [2]	—	—	—	—	—	—	—	—	—	180
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	—	(812)
Acquisitions of noncontrolling interests	—	—	—	—	—	—	(52)	—	(17)	(80)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	—	1,293
Sales to noncontrolling interests	—	—	—	—	—	—	170	(188)	8	968
Issuance of preferred shares in subsidiaries	—	—	—	—	—	—	—	—	—	30
Dividends declared on AES common stock ($0.7038/share)	—	—	—	—	—	—	(137)	(364)	—	—
Issuance and exercise of stock-based compensation benefit plans, net of income tax	—	—	0.1	—	(1.0)	12	10	—	—	—
Balance at December 31, 2025	—	$ —	859.8	$ 9	147.6	$(1,793)	$ 5,904	$ 641	$ (698)	$ 5,042

[1] Excludes redeemable stock of subsidiaries. See Note 17—*Redeemable Stock of Subsidiaries.*

[2] Related to the reclassification of AES Clean Energy Development common stock and certain tax equity partnerships at AES Clean Energy and AES Indiana from *Redeemable stock of subsidiaries* to *Noncontrolling interests*. See Note 17—*Redeemable Stock of Subsidiaries.*

See Accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows
Years ended December 31, 2025, 2024, and 2023

	2025	2024	2023
		(in millions)	
OPERATING ACTIVITIES:			
Net income (loss)	$ 162	$ 802	$ (182)
Adjustments to net income (loss):			
Depreciation, amortization, and accretion of AROs	1,457	1,264	1,147
Emissions allowance expense	361	238	264
Loss (gain) on realized/unrealized derivatives	48	(143)	143
Loss on commencement of sales-type leases	231	67	20
Gain on disposal and sale of business interests	(58)	(351)	(134)
Impairment expense	337	374	1,079
Loss on realized/unrealized foreign currency	54	108	331
Deferred income tax expense (benefit), net of tax credit transfers allocated to AES	92	111	(54)
Tax credit transfers allocated to noncontrolling interests	1,028	220	—
Other	395	154	110
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	130	(361)	161
(Increase) decrease in inventory	6	86	306
(Increase) decrease in prepaid expenses and other current assets	(25)	269	38
(Increase) decrease in other assets	5	(73)	5
Increase (decrease) in accounts payable and other current liabilities	215	(40)	(132)
Increase (decrease) in income tax payables, net, and other tax payables	(100)	(134)	(109)
Increase (decrease) in other liabilities	(32)	161	41
Net cash provided by operating activities	4,306	2,752	3,034
INVESTING ACTIVITIES:			
Capital expenditures	(5,929)	(7,392)	(7,724)
Acquisitions of business interests, net of cash and restricted cash acquired	(108)	(246)	(542)
Proceeds from the sale of business interests, net of cash and restricted cash sold	108	423	254
Sale of short-term investments	93	796	1,318
Purchase of short-term investments	(185)	(818)	(937)
Contributions and loans to equity affiliates	(19)	(103)	(178)
Purchase of emissions allowances	(309)	(206)	(268)
Other investing	139	(154)	(111)
Net cash used in investing activities	(6,210)	(7,700)	(8,188)
FINANCING ACTIVITIES:			
Borrowings under the revolving credit facilities	3,865	6,806	7,103
Repayments under the revolving credit facilities	(5,330)	(6,197)	(6,285)
Commercial paper borrowings, net	79	—	—
Issuance of recourse debt	800	1,450	1,400
Repayments of recourse debt	(898)	(200)	(500)
Issuance of non-recourse debt	5,866	7,236	4,521
Repayments of non-recourse debt	(3,817)	(4,306)	(2,495)
Payments for financing fees	(134)	(138)	(142)
Purchases under supplier financing arrangements	1,380	1,786	1,858
Repayments of obligations under supplier financing arrangements	(1,681)	(1,794)	(1,491)
Distributions to noncontrolling interests	(912)	(430)	(323)
Acquisitions of noncontrolling interests	(143)	—	(127)
Contributions from noncontrolling interests	437	222	102
Sales to noncontrolling interests	2,084	1,247	1,938
Issuance of preferred shares in subsidiaries	992	—	421
Dividends paid on AES common stock	(501)	(483)	(444)
Payments for financed capital expenditures	(53)	(127)	(10)
Other financing	(59)	(109)	(121)
Net cash provided by financing activities	1,975	4,963	5,405
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	(27)	(63)	(270)
(Increase) decrease in cash, cash equivalents, and restricted cash of held-for-sale businesses	79	97	(78)
Total increase (decrease) in cash, cash equivalents, and restricted cash	123	49	(97)
Cash, cash equivalents and restricted cash, beginning	2,039	1,990	2,087
Cash, cash equivalents and restricted cash, ending	$ 2,162	$ 2,039	$ 1,990

Consolidated Statements of Cash Flows *(continued)*
Years ended December 31, 2025, 2024, and 2023

	2025	2024	2023
		(in millions)	
SUPPLEMENTAL DISCLOSURES:			
Cash payments for interest, net of amounts capitalized	$ 1,210	$ 1,268	$ 1,317
Cash payments for income taxes, net of refunds (see Note 24)	227	345	301
SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES:			
Noncash contributions from noncontrolling interest related to tax credit transfers	1,028	220	—
Noncash contributions from noncontrolling interests	473	68	60
Noncash distributions to noncontrolling interests	423	—	—
Noncash recognition of new operating and financing leases (see Note 15)	204	456	225
Dividends declared but not yet paid	125	125	116
Initial recognition of contingent consideration for acquisitions (see Note 26)	40	76	239
Conversion of Corporate Units to shares of common stock (see Note 18)	—	838	—
Liabilities derecognized upon completion of remaining performance obligation for sale of Warrior Run receivables (see Note 21)	—	273	—
Noncash contributions to equity affiliates related to tax credit transfers	—	—	52

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 and partners. 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.

Consolidated VIEs — At December 31, 2025, the Company consolidates a number of entities that have been identified as VIEs under ASC 810, *Consolidation*. These entities are primarily limited liability entities or partnership arrangements with third-party investors structured to develop, construct, and operate power generation facilities and related assets. These entities were generally determined to have insufficient equity to finance their activities during development and construction without additional subordinated financial support. The Company also has tax equity arrangements entered into with third parties in order to monetize certain tax credits associated with renewables facilities. These tax equity partnerships meet the definition of a VIE as the holders of the membership interests, as a group, lack the characteristics of a controlling financial interest, including substantive kickout rights. Under these arrangements, the third-party investors are allocated earnings, tax attributes, and distributable cash in accordance with the respective limited liability company agreements. The assets of these tax equity partnerships are generally restricted from transfer under the terms of their limited liability company agreements. The third-party investor's ownership interest is recorded as either *Redeemable stock of subsidiaries* or *Noncontrolling interests* in the Consolidated Balance Sheets based on applicable guidance. See Note 17—*Redeemable Stock of Subsidiaries* and Note 18—*Equity* for further information.

Determining whether the Company is the primary beneficiary of a VIE requires judgment, including an assessment of contractual rights, operational responsibilities, and exposure to variability in returns. AES is considered the primary beneficiary of these VIEs when it has the power to direct the activities that most significantly affect their economic performance, such as construction, budgeting, operations, and maintenance, and it has the obligation to absorb expected losses and the right to receive benefits through its variable interests. As of December 31, 2025, certain consolidated VIEs have arrangements which may require the Company to contribute additional equity totaling $1.5 billion. Such contributions are generally contingent upon the underlying asset achieving specific project milestones. Certain consolidated VIEs are financed with non-recourse project-level debt. Creditors of these VIEs have no recourse to the Company beyond the VIE's assets. See Note 12—*Obligations* for further information.

Unconsolidated VIEs — The Company has noncontrolling interests in VIEs accounted for under the equity method. These entities include partnerships in which the limited partners do not have substantive rights over the significant activities of these entities, as well as renewable energy project joint ventures that have insufficient equity to finance their activities during development and construction without additional subordinated financial support. AES is not the primary beneficiary because it does not have a controlling financial interest in these entities and does not have the power to direct the activities that most significantly impact these VIEs' performance, and therefore does not consolidate any of these entities. AES' investment in these entities totaled approximately $127 million and $17 million as of December 31, 2025 and 2024, respectively, which are included in *Investments in and advances to affiliates* on the Consolidated Balance Sheets. See Note 9—*Investments In and Advances to Affiliates* for further information. AES' maximum exposure to loss is limited to current investments in these entities.

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.

Noncontrolling interests 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, these instruments are initially measured at fair value and are subsequently adjusted for income and dividends allocated to the noncontrolling interest. Subsequent measurement varies 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, any changes from the carrying value to redemption value are recognized in temporary equity against *Retained earnings* or *Additional paid-in capital* in the absence of retained earnings. When the 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* on 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* on 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 on disposal and sale of business interests* on 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.

Many of 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 were 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 renewables 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.

In some other arrangements, consolidated subsidiaries are subject to profit-sharing arrangements where cash distributions to noncontrolling interest holders are based on a stated internal rate of return, among other criteria. In many of these arrangements, earnings are allocated to noncontrolling interest holders based on the stated internal rate of return to the noncontrolling interest holders for any given 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; 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 continuing businesses, if any, are not eliminated, in order to appropriately reflect continuing operations and held-for-sale balances. See Note 25—*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, 2025	December 31, 2024
Cash and cash equivalents	$ 1,382	$ 1,524
Restricted cash [(1)]	691	437
Debt service reserves and other deposits [(2)]	89	78
Cash, Cash Equivalents and Restricted Cash	$ 2,162	$ 2,039

(1) Includes approximately $451 million and $79 million of cash maintained in accordance with certain covenants of non-recourse debt agreements and $153 million and $155 million of cash held as collateral to cover potential liabilities for current and future insurance claims being assumed by AGIC, AES' captive insurance company, for the years ended December 31, 2025 and 2024, respectively. See Note 12—*Obligations* for further information.

(2) Includes approximately $80 million and $68 million of cash maintained in accordance with certain covenants of non-recourse debt agreements for the years ended December 31, 2025 and 2024, respectively. See Note 12—*Obligations* for further information.

INVESTMENTS IN MARKETABLE SECURITIES — The Company's marketable investments are primarily certificates of deposit, mutual funds, and government debt securities.

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. Assets are placed in service 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.

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.* Net assets acquired in a business combination recognized as project development intangibles represent the value attributable to in-process development associated with future operating assets. An intangible asset is recognized when construction activities have yet to commence and the development work completed consists of contractual arrangements which are intangible in nature, such as permitting, contracting, and surveying. Amortization is computed using the straight-line method beginning when a project is placed in service and continuing over the estimated useful lives of the 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 on a straight-line basis 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, environmental remediation costs, and employee-related costs, including payroll, and benefits.

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 and categorized by level within the fair value hierarchy as described in Note 1—*General and Summary of Significant Accounting Policies—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'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 U.S. Inflation Reduction Act of 2022 (the "IRA") allows the owners of renewable energy projects to directly transfer ITCs to unrelated tax credit buyers. 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 under ASC 740—*Income Taxes,* 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 throughout the year the renewables project is placed in service. The Company applies the flow-through method to account for its investment tax credits. 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. In many cases, ITCs are generated at partnerships which are non-tax paying entities for U.S. federal income tax purposes. These entities cannot utilize tax credits, but rather allocate credits to their partners, who report their share of the partnership credits on their individual tax returns. Once a project is placed in service, any portion of the tax credit to be transferred which is allocated to a noncontrolling interest holder is recorded as a noncash deemed contribution within *Noncontrolling interests* or *Redeemable stock of subsidiaries* on the Consolidated Balance Sheets as this represents an increase in the partners' capital account. To the extent any of the expected transfer proceeds are contractually obligated to be distributed to the noncontrolling interest holder, the Company records a corresponding noncash deemed distribution within *Noncontrolling interests* or *Redeemable stock of subsidiaries*. The receipt of cash from the transfer of tax credits, inclusive of the portion allocated to noncontrolling interest holders, is treated as an operating cash inflow on the

Consolidated Statements of Cash Flows. Proceeds from the transfer of tax credits are excluded from the supplemental disclosure of *Cash payments for income taxes, net of refunds*.

During the year ended December 31, 2025, the Company executed agreements totaling $1.6 billion to transfer ITCs directly to third parties at a discount. Of this amount, $593 million was allocated to AES and recognized as an income tax benefit in 2025, and $1 billion was allocated to noncontrolling interests and treated as a contribution from noncontrolling interest holders. The Company received cash proceeds from these tax credit transfers of $1.2 billion during the year ended December 31, 2025, and recorded a receivable in *Other current assets* on the Consolidated Balance Sheets for the remaining $448 million, which is expected to be received in the first half of 2026. Of this amount, the Company is contractually obligated to distribute $414 million to the noncontrolling interest holders, and therefore recorded a corresponding payable in *Accrued and other liabilities* as of December 31, 2025.

During the year ended December 31, 2024, the Company executed agreements totaling $555 million to transfer ITCs directly to third parties at a discount. Of this amount, $309 million and $26 million was allocated to AES and recognized as income tax benefit in 2024 and 2023, respectively, and $220 million was allocated to noncontrolling interests and treated as a contribution from noncontrolling interest holders in 2024. The Company received cash proceeds from these tax credit transfers of $480 million during the year ended December 31, 2024, and recorded a receivable in *Other current assets* on the Consolidated Balance Sheets for the remaining $75 million, which was received in March 2025.

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 the development and construction of generation facilities, including from the sale of projects we develop and transfer. 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 requirements 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 revenue 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 21—*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. The Company has elected an accounting policy, applied to all classes of assets, to not separate lease components from non-lease components where the Company is a 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 obligations 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 receipts from such contracts are recognized as lease revenue on a straight-line basis over the lease term, whereas variable lease receipts 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. 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 qualified 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 totaled $63 million, $187 million, and $181 million for the years ended December 31, 2025, 2024, and 2023, respectively. The Company has elected not to offset derivative positions on the balance sheet where a right to offset exists.

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 Company has elected to write off accrued interest receivables by reversing interest income. 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 collectability of cash flows and considering information about past events, current conditions, and reasonable and supportable forecasts of future economic conditions.

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**
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 breakdown of income taxes paid in a 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.	December 31, 2025	The Company adopted the standard on a prospective basis. See Note 24—*Income Taxes* for impact.

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**
2024-03: Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40)	The amendments in this Update require disclosure, in the notes to financial statements, of specified information about certain costs and expenses. The amendments require that at each interim and annual reporting period an entity: 1. Disclose the amounts of (a) purchases of inventory, (b) employee compensation, (c) depreciation, (d) intangible asset amortization, and (e) depreciation, depletion, and amortization recognized as part of oil- and gas-producing activities (DD&A) (or other amounts of depletion expense) included in each relevant expense caption. A relevant expense caption is an expense caption presented on the face of the income statement within continuing operations that contains any of the expense categories listed in (a)–(e). 2. Include certain amounts that are already required to be disclosed under current generally accepted accounting principles (GAAP) in the same disclosure as the other disaggregation requirements. 3. Disclose a qualitative description of the amounts remaining in relevant expense captions that are not separately disaggregated quantitatively. 4. Disclose the total amount of selling expenses and, in annual reporting periods, an entity’s definition of selling expenses.	The date for each amendment in this Update is effective for fiscal years beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. Early adoption is permitted	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements. This ASU only affects disclosures, which will be provided when the amendment becomes effective.

2025-06: Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Targeted Improvements to the Accounting for Internal-Use Software	The amendments in this Update remove all references to prescriptive and sequential software development stages (referred to as "project stages") throughout Subtopic 350-40. Therefore, an entity is required to start capitalizing software costs when both of the following occur: 1. Management has authorized and committed to funding the software project. 2. It is probable that the project will be completed and the software will be used to perform the function intended. In evaluating the probable-to-complete recognition threshold, an entity is required to consider whether there is significant uncertainty associated with the development activities of the software. The two factors to consider in determining whether there is significant development uncertainty are whether: 1. The software being developed has technological innovations or novel, unique, or unproven functions or features, and the uncertainty related to those technological innovations, functions, or features, if identified, has not been resolved through coding and testing. 2. The entity has determined what it needs the software to do (for example, functions or features), including whether the entity has identified or continues to substantially revise the software's significant performance requirements.	The amendments in this Update are effective for fiscal years beginning after December 15, 2027, and interim reporting periods within those annual reporting periods. Early adoption is permitted as of the beginning of an annual reporting period.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.
2025-07,Derivatives and Hedging (Topic 815) and Revenue from Contracts with Customers (Topic 606): Derivatives Scope Refinements and Scope Clarification for Share-Based Noncash Consideration from a Customer in a Revenue Contract	Issue 1: Derivatives Scope Refinements The amendments in this Update exclude from derivative accounting non-exchange-traded contracts with underlyings that are based on operations or activities specific to one of the parties to the contract. Issue 2: Scope Clarification for Share-Based Noncash Consideration from a Customer in a Revenue Contract The amendments in this Update clarify that an entity should apply the guidance in Topic 606, including the guidance on noncash consideration to a contract with share-based noncash consideration (for example, shares, share options, or other equity instruments) from a customer for the transfer of goods or services.	The amendments in this Update are effective for fiscal years beginning after December 15, 2026, and interim reporting periods within those annual reporting periods. Early adoption is permitted.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.
2025-09: Hedge Accounting Improvements	Issue 1: Similar Risk Assessment for Cash Flow Hedges The amendments in this Update permit grouping forecasted transactions in a cash flow hedge based on similar risk exposures, subject to initial and ongoing risk assessments. Issue 2: Hedging Forecasted Interest Payments on Choose-Your-Rate Debt The amendments in this Update provide a model to facilitate the application of cash flow hedge accounting for forecasted interest payments on variable-rate debt that permits borrowers to change the interest rate index and reset frequency ("choose-your-rate" debt). Issue 3: Cash Flow Hedges of Nonfinancial Forecasted Transactions The amendments in this Update expand hedge accounting for forecasted purchases and sales of nonfinancial assets by allowing hedging of eligible price components and subcomponents, subject to specific criteria. Issue 4: Net Written Options as Hedging Instruments The amendments in this Update eliminate the requirement to apply the net written option test to compound derivatives consisting of a swap and a written option that are designated as hedging instruments in cash flow or fair value hedges of interest rate risk. Issue 5: Foreign-Currency-Denominated Debt Used in Dual Hedges The amendments in this Update eliminate recognition and presentation mismatches in dual hedge strategies by excluding fair value hedge basis adjustments from net investment hedge effectiveness assessments and requiring related foreign exchange gains and losses to be recognized in earnings.	The amendments in this Update are effective for annual reporting periods beginning after December 15, 2026, and interim periods within those annual reporting periods, and should be applied prospectively for all hedging relationships that exist at the date of adoption.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.

2025-11: Interim Reporting (Topic 270)—Narrow-Scope Improvements	The amendments in this Update clarify interim disclosure requirements and the applicability of Topic 270 by organizing existing GAAP interim disclosure requirements into a single framework and clarifying when additional disclosures are required for material events occurring after the most recent annual reporting period.	The amendments in this Update are effective for fiscal years beginning after December 15, 2027, and interim reporting periods within those annual reporting periods.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.
2025-12: Codification Improvements	The amendments in this Update include 34 issues that represent changes to the Codification that clarify, correct errors, or make minor improvements, making the Codification easier to understand and apply. The amendments in this Update are varied in nature and may affect the application of guidance in cases in which the original guidance may have been unclear.	The amendments in this Update are effective for fiscal years beginning after December 15, 2026, and interim reporting periods within those annual reporting periods. Early adoption is permitted on an issue-by-issue basis as of the beginning of an annual reporting period.	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,	**2025**	**2024**
Spare parts and supplies	$ 392	$ 347
Fuel and other raw materials	220	246
Total	$ 612	$ 593

3. PROPERTY, PLANT, AND EQUIPMENT

The following table summarizes the components of 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, 2025**	**2024**
Electric generation and distribution facilities	5-40	$ 35,509	$ 29,740
Other buildings	7-48	1,308	1,232
Furniture, fixtures, and equipment	2-30	460	423
Other	10-39	1,800	1,428
Total electric generation, distribution assets and other		39,077	32,823
Accumulated depreciation		(9,796)	(8,701)
Net electric generation, distribution assets and other		$ 29,281	$ 24,122
Land		645	610
Construction in progress		7,892	8,434
Property, plant, and equipment, net		$ 37,818	$ 33,166

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,	**2025**	**2024**	**2023**
Depreciation expense	$ 1,330	$ 1,146	$ 1,045
Interest capitalized during development and construction	521	637	563

Property, plant, and equipment, net of accumulated depreciation, of $11.6 billion and $9.9 billion was mortgaged, pledged or subject to liens as of December 31, 2025 and 2024, 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,	2025	2024
Non-regulated electric generation assets and other, gross	$ 27,432	$ 21,954
Non-regulated accumulated depreciation	(5,515)	(4,704)
Non-regulated electric generation assets and other, net	21,917	17,250
Regulated electric generation, distribution assets and other, gross	11,645	10,869
Regulated accumulated depreciation	(4,281)	(3,997)
Regulated electric generation, distribution assets and other, net	7,364	6,872
Net electric generation, distribution assets and other	$ 29,281	$ 24,122

4. ASSET RETIREMENT OBLIGATIONS

The following table presents amounts recognized related to asset retirement obligations for the periods indicated (in millions):

	2025	2024
Balance at January 1	$ 920	$ 778
Additional liabilities incurred	149	61
Liabilities settled	(35)	(30)
Accretion expense [(1)]	43	41
Change in estimated cash flows	143	127
Sale of business or reclassification to held-for-sale liabilities	—	(58)
Other	4	1
Balance at December 31	$ 1,224	$ 920

(1) Includes $18 million and $16 million at AES Indiana for the years ended December 31, 2025 and 2024, respectively, reflected as a change in regulatory liabilities on the Consolidated Balance Sheets. See Note 11—*Regulatory Assets and Liabilities* for further information.

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 expected cash flow technique 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, 2025, the Company increased the asset retirement obligations and corresponding assets at AES Indiana and AES Clean Energy by $195 million and $83 million, respectively. The increase at AES Indiana was primarily driven by Corrective Measures Assessments at Harding Street and Petersburg related to ash ponds and groundwater treatment as well as additional CCR liabilities at Petersburg, Harding Street, and Eagle Valley. The increase at AES Clean Energy is mostly due to additional liabilities incurred for sites that were placed in service during 2025.

During the year ended December 31, 2024, the Company increased the asset retirement obligations and corresponding assets at AES Indiana and AES Clean Energy by $129 million and $73 million, respectively. The increase at AES Indiana is primarily related to revisions to cash flow estimates due to increases in closure costs and groundwater treatment measures for ash ponds and landfills. The increase at AES Clean Energy is mostly due to additional liabilities incurred for sites that were placed in service during 2024. This was offset by decreases at Ventanas of $43 million due to held-for-sale classification in December 2024, and $15 million at AES Brasil due to the sale of the business in October 2024.

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), equity method investments, goodwill, and intangible assets (e.g., sales concessions, land use rights, 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 certificates of deposit. 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.

Contingent consideration — Contingent consideration is primarily related to future milestone payments associated with acquisitions of renewables 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. Gains and losses on the remeasurement of contingent consideration are recognized in *Other income* and *Other expense*, respectively, on the Consolidated Statements of Operations.

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, 2025. The Company is not aware of any factors that would significantly affect the fair value amounts subsequent to December 31, 2025.

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 for business interests classified as held-for-sale and for 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, 2025				December 31, 2024			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
DEBT SECURITIES:								
Available-for-sale:								
Certificates of deposit	$ —	$ 3	$ —	$ 3	$ —	$ 4	$ —	$ 4
Government debt securities	—	—	—	—	—	4	—	4
Total debt securities	—	3	—	3	—	8	—	8
EQUITY SECURITIES:								
Mutual funds	57	—	—	57	51	—	—	51
Common stock	1	—	—	1	4	—	—	4
Total equity securities	58	—	—	58	55	—	—	55
DERIVATIVES:								
Interest rate derivatives	—	279	—	279	—	349	—	349
Foreign currency derivatives	—	24	—	24	—	9	52	61
Commodity derivatives	109	72	5	186	193	80	5	278
Total derivatives — assets [(1)]	109	375	5	489	193	438	57	688
TOTAL ASSETS	$ 167	$ 378	$ 5	$ 550	$ 248	$ 446	$ 57	$ 751
Liabilities								
Contingent consideration [(2)]	$ —	$ —	$ 205	$ 205	$ —	$ —	$ 145	$ 145
DERIVATIVES:								
Interest rate derivatives	—	59	—	59	—	14	1	15
Foreign currency derivatives	—	28	—	28	—	18	—	18
Commodity derivatives	110	42	45	197	185	44	26	255
Total derivatives — liabilities [(1)]	110	129	45	284	185	76	27	288
TOTAL LIABILITIES	$ 110	$ 129	$ 250	$ 489	$ 185	$ 76	$ 172	$ 433

(1) Includes $3 million of derivative assets reported in *Current held-for-sale assets* and $3 million of derivative liabilities reported in *Current held-for-sale liabilities* on the Consolidated Balance Sheets related to Dominican Republic Renewables as of December 31, 2024.

(2) The Level 3 contingent consideration is mainly related to the acquisition of Bellefield in June 2023.

As of December 31, 2025, all available-for-sale debt securities had stated maturities within one year. For the years ended December 31, 2025 and 2024, no impairments of marketable securities were recognized in earnings or other comprehensive income (loss). Gains and losses on sales 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,	2025	2024	2023
Gross proceeds from sale of available-for-sale securities	$ 7	$ 717	$ 1,377

The Company accounts for equity securities without readily determinable fair values using the measurement alternative in accordance with ASC 321*.* These securities are measured at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or similar investments of the same issuer. Upward adjustments resulting from observable price changes are recorded in *Other income* and impairments and downward adjustments are recorded in *Other expense*. As of December 31, 2024, the carrying amount of equity securities accounted for using the measurement alternative was $62 million, inclusive of $22 million of cumulative upward adjustments recorded in *Other income* in prior years to reflect observable price changes for our investment in 5B Holdings Ptd. Ltd. ("5B"). In June 2025, the Company recorded a $48 million downward adjustment to our investment in 5B in *Other expense* due to an observable price change resulting from a transaction between 5B and a third party. The carrying amount of equity securities accounted for using the measurement alternative as of December 31, 2025 was $19 million.

The following tables present a reconciliation of assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the years ended December 31, 2025 and 2024 (derivative balances are presented net), 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, 2025	Derivative Assets and Liabilities: Interest Rate	Derivative Assets and Liabilities: Foreign Currency	Derivative Assets and Liabilities: Commodity	Contingent Consideration	Total
Balance at January 1	$ (1)	$ 52	$ (21)	$ (145)	$ (115)
Total realized and unrealized gains (losses):					
Included in earnings	—	3	—	(79)	(76)
Included in other comprehensive income (loss) — derivative activity	1	1	(16)	—	(14)
Included in regulatory (assets) liabilities	—	—	5	—	5
Acquisitions	—	—	—	(40)	(40)
Settlements	—	(40)	(5)	59	14
Transfers of assets/(liabilities), net into Level 3	—	—	(3)	—	(3)
Transfers of (assets)/liabilities, net out of Level 3	—	(16)	—	—	(16)
Balance at December 31	$ —	$ —	$ (40)	$ (205)	$ (245)
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	$ —	$ —	$ —	$ (79)	$ (79)

Year Ended December 31, 2024	Derivative Assets and Liabilities: Interest Rate	Derivative Assets and Liabilities: Foreign Currency	Derivative Assets and Liabilities: Commodity	Contingent Consideration	Total
Balance at January 1	$ (4)	$ 59	$ (110)	$ (165)	$ (220)
Total realized and unrealized gains (losses):					
Included in earnings	—	23	4	(10)	17
Included in other comprehensive income (loss) — derivative activity	3	8	84	—	95
Included in other comprehensive income (loss) — foreign currency translation activity	—	—	—	1	1
Included in regulatory (assets) liabilities	—	—	5	—	5
Acquisitions	—	—	—	(76)	(76)
Settlements	—	(38)	(4)	105	63
Balance at December 31	$ (1)	$ 52	$ (21)	$ (145)	$ (115)
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	$ —	$ (6)	$ 6	$ (10)	$ (10)

The following table summarizes the significant unobservable inputs used for the Level 3 derivative assets (liabilities) as of December 31, 2025 (in millions, except range amounts):

Type of Derivative	Fair Value	Unobservable Input	Amount or Range (Average)
Commodity:			
CAISO energy swap	$ (38)	Forward CAISO energy prices per MWh from 2032 through 2038	$11.63 to $163.83 ($78.30)
MISO energy swap	(4)	Forward MISO energy prices per MWh from 2032 through 2040	$23.83 to $75.68 ($47.08)
Other	2		
Total	$ (40)		

For the CAISO and MISO energy swaps, increases (decreases) in the estimates above would decrease (increase) the value of the derivative.

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 and is included in *Asset impairment expense* or *Other non-operating expense* on the Consolidated Statements of Operations, as applicable. 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, 2025 Assets	Measurement Date	Carrying Amount (1)	Fair Value: Level 1	Fair Value: Level 2	Fair Value: Level 3	Pre-tax Loss
Held-for-sale businesses: (2)						
Mong Duong (3)	3/31/2025	$ 383	$ —	$ 371	$ —	$ 17
Equity method investments: (4)						
Uplight	9/30/2025	$ 60	$ —	$ —	$ —	$ 60
Long-lived asset groups held and used: (5)						
Maritza (6)	10/31/2025	$ 405	$ —	$ —	$ 141	$ 264

Year Ended December 31, 2024 Assets	Measurement Date	Carrying Amount (1)	Fair Value			Pre-tax Loss
			Level 1	Level 2	Level 3	
Held-for-sale businesses: (2)						
Mong Duong	3/31/2024	$ 450	$ —	$ 413	$ —	$ 37
AES Brasil (7)	5/15/2024	1,577	—	1,565	—	25
Mong Duong (3)	6/30/2024	390	—	389	—	6
AES Brasil (8)	9/30/2024	1,581	—	1,548	—	55
Mong Duong (3)	9/30/2024	407	—	400	—	11
Mong Duong (3)	12/31/2024	365	—	362	—	8
Ventanas	12/31/2024	131	—	6	—	125

(1) Represents the carrying values of the asset groups at the dates of measurement, before fair value adjustment.

(2) See Note 25—*Held-for-Sale and Dispositions* for further information.

(3) The pre-tax loss recognized was calculated using the fair value of the Mong Duong disposal group less costs to sell of $5 million.

(4) See Note 9—*Investments in and Advances to Affiliates* for further information.

(5) See Note 23—*Asset Impairment Expense* for further information.

(6) The carrying value of the Maritza asset group excludes accumulated foreign currency translation adjustments of $126 million.

(7) The pre-tax loss recognized was calculated using the fair value of the AES Brasil disposal group less costs to sell of $13 million. A subsequent impairment analysis was performed as of June 30, 2024 and no additional impairment was identified.

(8) The pre-tax loss recognized was calculated using the fair value of the AES Brasil disposal group less costs to sell of $22 million.

Mong Duong — During the year ended December 31, 2025, the Company recognized a $243 million increase in the carrying value of the Mong Duong asset group due to the derecognition of a $239 million valuation allowance on the loan receivable accounted for under ASC 310, which had been recognized in *Asset impairment expense* between December 31, 2023 and March 31, 2025 while Mong Duong was classified as held-for-sale, and the elimination of $4 million in net estimated costs to sell from the measurement of the asset group. Upon reclassification out of held-for-sale, the loan receivable was remeasured at amortized cost and individual non-loan assets were remeasured at the lower of (i) carrying value before Mong Duong was classified as held for sale, adjusted for any depreciation expense or impairment losses that would have been recognized had the asset been continuously classified as held and used, or (ii) fair value at the date of the subsequent determination that held-for-sale criteria was no longer met. See Note 23—*Asset Impairment Expense* 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 determined 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 $157 million, $95 million, and $151 million of pre-tax asset impairment expense in 2025, 2024, and 2023, respectively, including $137 million during the fourth quarter of 2023 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 23—*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, 2025 (in millions, except range amounts):

December 31, 2025	Fair Value	Valuation Technique	Unobservable Input	Range
Long-lived asset groups held and used:				
Maritza	$ 141	Discounted cash flow	Discount rate	26 %

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 dates indicated, but for which fair value is disclosed:

		December 31, 2025				
		Carrying Amount	Fair Value			
			Total	Level 1	Level 2	Level 3
Assets:	Financing receivables [1]	$ 855	$ 955	$ —	$ —	$ 955
Liabilities:	Non-recourse debt	23,178	23,749	—	20,448	3,301
	Recourse debt	5,984	5,003	—	5,003	—

		December 31, 2024				
		Carrying Amount	Fair Value			
			Total	Level 1	Level 2	Level 3
Assets:	Financing receivables [1]	$ 87	$ 171	$ —	$ —	$ 171
Liabilities:	Non-recourse debt	22,743	23,066	—	20,981	2,085
	Recourse debt	5,704	4,538	—	4,538	—

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(1) As of December 31, 2025, the amounts primarily relate to the Mong Duong loan receivable. For both periods presented, amounts also include payment deferrals granted to mining customers as part of our green blend agreements in Chile, the sale of the Redondo Beach land, and the fair value of the Argentine FONINVEMEM receivables. These are included in *Loan receivable* and *Other noncurrent assets* on the Consolidated Balance Sheets. See Note 7—*Financing Receivables* for further information.

6. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Volume of Activity — The following tables present the Company's maximum notional (in millions) over the remaining contractual period by type of derivative as of December 31, 2025, 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 [1]
Interest rate	$ 10,699	2058
Foreign currency:		
Chilean peso	192	2028
Colombian peso	191	2028
Euro	153	2028

Commodity Derivatives	Maximum Notional	Latest Maturity
Natural Gas (in MMBtu)	91	2029
Power (in MWhs) [2]	31	2040

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(1) Maturity dates are consistent for both designated and non-designated positions.

(2) Includes one contract designated as a cash flow hedge with a final maturity date in 2038.

Accounting and Reporting — *Assets and Liabilities* — The following tables present the fair value of the Company's derivative assets and liabilities as of the dates indicated (in millions):

Fair Value	December 31, 2025			December 31, 2024		
Assets	Designated	Not Designated	Total	Designated	Not Designated	Total
Interest rate derivatives	$ 279	$ —	$ 279	$ 349	$ —	$ 349
Foreign currency derivatives	11	13	24	16	45	61
Commodity derivatives	4	182	186	4	274	278
Total assets	$ 294	$ 195	$ 489	$ 369	$ 319	$ 688
Liabilities						
Interest rate derivatives	$ 59	$ —	$ 59	$ 15	$ —	$ 15
Foreign currency derivatives	4	24	28	10	8	18
Commodity derivatives	46	151	197	29	226	255
Total liabilities	$ 109	$ 175	$ 284	$ 54	$ 234	$ 288

	December 31, 2025		December 31, 2024	
Fair Value	Assets	Liabilities	Assets	Liabilities
Current	$ 261	$ 154	$ 369	$ 170
Noncurrent	228	130	319	118
Total [1]	$ 489	$ 284	$ 688	$ 288

(1) Includes $3 million of derivative assets reported in *Current held-for-sale assets* and $3 million of derivative liabilities reported in *Current held-for-sale liabilities* on the Consolidated Balance Sheets related to Dominican Republic Renewables as of December 31, 2024.

Credit Risk-Related Contingent Features	December 31, 2025	December 31, 2024
Asset position of commodities derivatives subject to master netting arrangements and subject to collateralization	$ 109	$ 193
Liability position of commodities derivatives subject to master netting arrangements and subject to collateralization	(110)	(185)
Cash collateral held by third parties or in escrow	2	54

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,		
	2025	2024	2023
Cash flow hedges			
Gains (losses) recognized in AOCL			
Interest rate derivatives	$ (45)	$ 493	$ 42
Foreign currency derivatives	11	(12)	2
Commodity derivatives	(17)	80	(48)
Total	$ (51)	$ 561	$ (4)
Gains (losses) reclassified from AOCL to earnings			
Interest rate derivatives — Interest expense	$ 3	$ (32)	$ 51
Foreign currency derivatives — Foreign currency transaction gains (losses)	7	(6)	(4)
Commodity derivatives — Cost of sales—Non-Regulated	(1)	—	17
Total	$ 9	$ (38)	$ 64
Gains (losses) on fair value hedging relationships			
Cross-currency derivatives			
Derivatives designated as hedging instruments	$ —	$ 63	$ (72)
Hedged items	—	(58)	58
Total	$ —	$ 5	$ (14)
Gains reclassified from AOCL to earnings due to change in forecast	$ 8	$ 11	$ 14
Gain (losses) recognized in earnings related to			
Not designated as hedging instruments:			
Interest rate derivatives — Interest expense	$ (2)	$ —	$ (7)
Foreign currency derivatives — Foreign currency transaction gains (losses)	(8)	66	19
Commodity derivatives — Revenue—Non-Regulated	72	255	205
Commodity derivatives — Cost of sales—Non-Regulated	(48)	(97)	56
Total	$ 14	$ 224	$ 273

Reclassifications from AOCL to earnings are forecasted to decrease pre-tax income from continuing operations by $20 million for the twelve months ended December 31, 2026, primarily related to foreign currency derivatives.

7. FINANCING RECEIVABLES

Receivables with contractual maturities of greater than one year are considered financing receivables. The following table presents long-term financing receivables, excluding lease receivables and amounts classified as held for sale, by country as of the dates indicated (in millions).

	December 31, 2025			December 31, 2024		
	Gross Receivable	Allowance	Net Receivable	Gross Receivable	Allowance	Net Receivable
Vietnam	$ 774	$ 19	$ 755	$ —	$ —	$ —
Chile	61	—	61	45	—	45
U.S.	51	19	32	48	15	33
Other	7	—	7	9	—	9
Total	$ 893	$ 38	$ 855	$ 102	$ 15	$ 87

Vietnam — AES has recorded loan receivables of $862 million as of December 31, 2025 pertaining to our Mong Duong plant in Vietnam. During the years ended December 31, 2025 and 2024, the Company collected $103 million and $110 million, respectively. The plant was constructed under a build, operate, and transfer contract and sold to the Vietnamese government, while we remain the operator for the duration of the 25-year PPA. Mong Duong was reclassified from held-for-sale to held and used as of May 31, 2025 and therefore $107 million was classified in *Other current assets*, and $755 million in *Loan receivable* on the Consolidated Balance Sheets as of December 31,

2025. See Note 21—*Revenue* and Note 25—*Held-for-Sale and Dispositions* for further information.

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, August 2022, and April 2024, 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 renewables contracts are incorporated to supply regulated contracts. Consequently, costs incurred in excess of the July 1, 2019 price were accumulated and borne by generators. AES Andes aimed to reduce its exposure through the sale of receivables.

AES Andes executed agreements in August 2023 and October 2024 to sell up to $227 million and $254 million of receivables, respectively, pursuant to the Stabilization Funds. As of December 31, 2025, through these different agreements, AES Andes sold and collected $151 million and $228 million, respectively. In April 2025, AES Andes sold and collected the remaining $11 million of receivables pursuant to the Stabilization Funds. Additionally, $55 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, 2025.

U.S. — AES has recorded noncurrent receivables pertaining to the sale of the Redondo Beach land. The anticipated collection period extends beyond December 31, 2026.

8. ALLOWANCE FOR CREDIT LOSSES

The following table represents the rollforward of the allowance for credit losses for the periods indicated (in millions):

Twelve Months Ended December 31, 2025	Accounts Receivable	Financing Receivables	Other [(1)]	Total
CECL reserve balance at beginning of period	$ 52	$ 15	$ 29	$ 96
Reclassification from held-for-sale to held and used	—	21	(21)	—
Current period provision	46	5	—	51
Write-offs charged against allowance	(55)	—	—	(55)
Recoveries collected	(5)	(3)	—	(8)
Foreign exchange	1	—	(2)	(1)
CECL reserve balance at end of period	$ 39	$ 38	$ 6	$ 83

Twelve Months Ended December 31, 2024	Accounts Receivable	Financing Receivables	Other [(2)]	Total
CECL reserve balance at beginning of period	$ 15	$ 2	$ 47	$ 64
Current period provision	43	13	2	58
Write-offs charged against allowance	(7)	—	(6)	(13)
Recoveries collected	1	—	(3)	(2)
Allowance derecognized due to disposal of a business	—	—	(7)	(7)
Foreign exchange	—	—	(4)	(4)
CECL reserve balance at end of period	$ 52	$ 15	$ 29	$ 96

(1) Primarily relates to credit losses on Argentina receivables as of December 31, 2025.

(2) Primarily relates to credit losses allowance classified in *Current held-for-sale assets* and *Noncurrent held-for-sale assets* on the Consolidated Balances Sheets, and credit losses allowance at AES Brasil which was sold on October 31, 2024.

In 2024 and 2025, the current period provision and allowance for credit losses on customer accounts receivable increased due to a temporary pause of customer disconnections and certain collection efforts and write-off processes after the implementation of customer billing system upgrades at our utilities in 2023 and 2024. This resulted in higher past due customer receivables as of December 31, 2024 and 2025. AES Indiana and AES Ohio reinstituted customer disconnections and write-off processes in March and June 2025, respectively. As a result, $54 million of the $55 million in write-offs charged against allowance for the year ended December 31, 2025 were related to AES Indiana and AES Ohio.

9. 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,		2025	2024	2025	2024
Affiliate	Country	Carrying Value (in millions)		Ownership Interest %	
sPower [1]	United States	$ 502	$ 548	50 %	50 %
Fluence	United States	139	155	28 %	28 %
Grupo Energía Gas Panamá [2]	Panama	135	194	24 %	24 %
Dominican Republic Renewables [3]	Dominican Republic	109	—	33 %	— %
Mesa La Paz	Mexico	38	43	50 %	50 %
Energía Natural Dominicana Enadom [3]	Dominican Republic	35	65	33 %	33 %
Uplight	United States	—	82	25 %	25 %
Other affiliates [4]	Various	46	37		
Total		$ 1,004	$ 1,124		

(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) The Company's ownership in Energía Natural Dominicana Enadom and Dominican Republic Renewables is held through Andres and AES Hispanola Holdings II BV, respectively, each of which are 65%-owned consolidated subsidiaries. Andres and AES Hispanola Holdings II BV own 50% of Energía Natural Dominicana Enadom and Dominican Republic Renewables, respectively, resulting in an AES effective ownership of 33%. Dominican Republic Renewables is a VIE in which the Company holds a variable interest but is not the primary beneficiary.

(4) Includes Bosforo, Jordan, Barry, Alto Maipo, and various other equity method investments. Jordan, Barry, and Alto Maipo represent VIEs in which the Company holds a variable interest but is not the primary beneficiary.

Uplight — In February 2024, Uplight acquired AutoGrid, a market leader in the Virtual Power Plant space, from Schneider Electric. As part of the transaction, Schneider contributed an additional $40 million to Uplight, and Uplight issued approximately 91 million additional common units to Schneider as consideration for the acquisition. No incremental investment was required from AES or any other investor. As a result, AES' 29% ownership interest in Uplight was diluted to 25%. The transaction was accounted for as a partial disposition in which AES recognized a gain of $52 million in *Gain on disposal and sale of business interests* upon remeasurement. As the Company still did not control but had significant influence over Uplight after the transaction, it continued to be accounted for as an equity method investment.

During 2025, an other-than-temporary impairment of the Company’s investment in Uplight was identified due to observable market factors. As the carrying amounts of the equity method investment and convertible notes for Uplight were greater than their fair values, the Company recognized an impairment of $103 million in *Other non-operating expense*. After the impact of the impairment, the carrying amount of the equity method investment was reduced to zero and the equity method of accounting was suspended. Uplight is reported in the New Energy Technologies SBU reportable segment.

Dominican Republic Renewables — In June 2025, the Company completed the sale of 50% of its interest in AES DR Renewables Holdings, S.L. and its subsidiaries (collectively “Dominican Republic Renewables”) for $103 million. The Company retained a 50% ownership interest in Dominican Republic Renewables after the sale. However, the Company’s ownership in Dominican Republic Renewables is held through AES Hispanola Holdings II BV, a 65%-owned consolidated subsidiary, resulting in an AES effective ownership of 33%. The business was deconsolidated and is accounted for as an equity method investment. The Company recorded its retained interest in Dominican Republic Renewables at fair value of $103 million, using the market approach. See Note 25—*Held-for-Sale and Dispositions* for further information. Dominican Republic Renewables is reported in the Renewables SBU reportable segment.

Jordan — In March 2024, the Company completed the sale of approximately 26% ownership interest in Amman East and IPP4 for a sale price of $58 million. After adjusting for dividends received since the execution of the sale and purchase agreement, the Company received a net cash payment of $45 million. After completion of the sale, the Company retained 10% ownership interest in each of the businesses, which are accounted for as equity method investments. See Note 25—*Held-for-Sale and Dispositions* for further information. Amman East and IPP4 are reported in the Energy Infrastructure SBU reportable segment.

Alto Maipo — The Company holds a 99% ownership interest in Alto Maipo SpA ("Alto Maipo"), a hydroelectric plant in Chile. 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 does 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 both December 31, 2025 and 2024, the fair value was insignificant. Alto Maipo is reported in the Renewables 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 both December 31, 2025 and 2024, other long-term liabilities included $44 million and $41 million 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,	**2025**	**2024**	**2023**	**2025**	**2024**	**2023**
Revenue	$ 3,346	$ 3,553	$ 2,905	$ —	$ 1	$ 1
Operating income (loss)	134	141	(28)	—	(1)	(1)
Net loss	(188)	(107)	(182)	(2)	(1)	(1)
Net loss attributable to affiliates	(177)	(12)	(157)	(2)	(1)	(1)
December 31,	**2025**	**2024**		**2025**	**2024**	
Current assets	$ 2,745	$ 2,493		$ 135	$ 132	
Noncurrent assets	8,335	7,808		279	408	
Current liabilities	2,159	2,023		133	129	
Noncurrent liabilities	5,199	4,270		322	448	
Stockholders' equity	2,642	2,960		(41)	(37)	
Noncontrolling interests	1,080	1,048		—	—	

(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, 2025, retained earnings included $446 million related to the undistributed losses of the Company's affiliates. Dividends received from our affiliates were $8 million, $32 million, and $5 million for the years ended December 31, 2025, 2024, and 2023, respectively. As of December 31, 2025, the underlying equity in the net assets of our equity affiliates exceeded the aggregate carrying amount of our investments in equity affiliates by $51 million.

10. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill — The following table summarizes the carrying amount of goodwill by reportable segment for the years ended December 31, 2025 and 2024 (in millions):

	Renewables SBU	Utilities SBU	Energy Infrastructure SBU	New Energy Technologies SBU	Total
Balance as of December 31, 2024					
Goodwill	$ 353	$ 2,709	$ 683	$ —	$ 3,745
Accumulated impairment losses	(35)	(2,709)	(656)	—	(3,400)
Net balance	318	—	27	—	345
Goodwill derecognized during the year	(3)	—	—	—	(3)
Balance as of December 31, 2025					
Goodwill	350	2,709	683	—	3,742
Accumulated impairment losses	(35)	(2,709)	(656)	—	(3,400)
Net balance	$ 315	$ —	$ 27	$ —	$ 342

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 2024, TEG and TEP successfully migrated to the new energy regime and currently operate according to ISO instructions. TEG and TEP are reported in the Energy Infrastructure 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 dates indicated:

	December 31, 2025			December 31, 2024		
	Gross Balance	Accumulated Amortization	Net Balance	Gross Balance	Accumulated Amortization	Net Balance
Subject to Amortization						
Internal-use software	$ 824	$ (379)	$ 445	$ 794	$ (333)	$ 461
Contracts	39	(15)	24	68	(29)	39
Project development [1]	1,398	(53)	1,345	1,328	(37)	1,291
Emissions allowances [2]	83	—	83	1	—	1
Concession rights	19	(19)	—	19	(19)	—
Land use rights	119	(4)	115	108	(3)	105
Other [3]	28	(9)	19	28	(5)	23
Subtotal	2,510	(479)	2,031	2,346	(426)	1,920
Indefinite-Lived Intangible Assets						
Land use rights	7	—	7	8	—	8
Transmission rights	—	—	—	17	—	17
Other	2	—	2	2	—	2
Subtotal	9	—	9	27	—	27
Total	$ 2,519	$ (479)	$ 2,040	$ 2,373	$ (426)	$ 1,947

(1) Includes emission offset fee to the Air Quality Management District 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, 2025	Amount	Subject to Amortization/ Indefinite-Lived	Weighted Average Amortization Period (in years)	Amortization Method
Project development	$ 129	Subject to amortization	20	Straight-line
Emissions allowances	99	Subject to amortization	Various	As utilized
Internal-use software	40	Subject to amortization	9	Straight-line
Land use rights	11	Subject to amortization	14	Straight-line
Other	1	Various	N/A	N/A
Total	$ 280			

December 31, 2024	Amount	Subject to Amortization/ Indefinite-Lived	Weighted Average Amortization Period (in years)	Amortization Method
Project development	$ 134	Subject to Amortization	40	Straight-line
Internal-use software	114	Subject to Amortization	11	Straight-line
Emissions allowances	8	Subject to Amortization	Various	As utilized
Land use rights	2	Various	N/A	Various
Other	8	Various	N/A	N/A
Total	$ 266			

The following table summarizes the estimated amortization expense by intangible asset category for 2026 through 2030:

(in millions)	2026	2027	2028	2029	2030
Internal-use software	$ 71	$ 67	$ 63	$ 61	$ 56
Contracts	1	1	1	1	1
Project development	19	19	19	19	19
Other	2	2	2	1	1
Total	$ 93	$ 89	$ 85	$ 82	$ 77

Intangible asset amortization expense was $94 million, $88 million, and $82 million for the years ended December 31, 2025, 2024, and 2023, respectively.

11. 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,	2025	2024	Recovery/Refund Period Ends
Regulatory assets			
Current regulatory assets:			
Undercollection of rate riders	$ 121	$ 177	2026
El Salvador energy pass through costs recovery	106	117	2026
Other	22	37	2026
Total current regulatory assets	249	331	
Noncurrent regulatory assets:			
AES Indiana and AES Ohio defined benefit pension obligations [1]	158	183	Various
AES Indiana Petersburg Units 3 and 4 retirement costs [1] [2]	133	116	Undetermined
AES Indiana Petersburg Units 1 and 2 retirement costs [1]	113	129	2033
AES Indiana TDSIC costs [1]	72	52	2060
AES Indiana environmental costs	54	65	2044
AES Indiana Hoosier Wind termination of pre-existing PPA [1] [3]	48	53	2039
AES Ohio regulatory compliance costs [1]	24	33	2028
El Salvador energy pass through costs recovery	—	39	Various
Other	149	121	Various
Total noncurrent regulatory assets	751	791	
Total regulatory assets	$ 1,000	$ 1,122	
Regulatory liabilities			
Current regulatory liabilities:			
Overcollection of costs to be passed back to customers	$ 27	$ 18	2026
Other	7	4	2026
Total current regulatory liabilities	34	22	
Noncurrent regulatory liabilities:			
AES Indiana and AES Ohio accrued costs of removal and AROs	328	465	Life of assets
AES Indiana and AES Ohio income taxes payable to customers through rates	99	93	Various
Other	22	5	Various
Total noncurrent regulatory liabilities	449	563	
Total regulatory liabilities	$ 483	$ 585	

(1) Past expenditures on which the Company earns a rate of return.

(2) Petersburg Units 3 and 4 retirement costs, including materials and supplies inventories, included in the pending rate case filed with IURC in June 2025. Recovery period pending final order from the IURC.

(3) AES Indiana acquired the Hoosier Wind project in February 2024. See Note 26—*Acquisitions* for further information.

Our current regulatory assets and 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 noncurrent regulatory assets 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, as well as the carrying value of AES Indiana's Petersburg Units 1 through 4 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:

- Project development costs, mainly legal and consulting fees, incurred for renewables projects as well as carrying costs on AES Indiana's investments in the projects;
- Vegetation management costs and proactive reliability optimization at AES Ohio;
- Deferred Midcontinent ISO costs at AES Indiana; and
- Unamortized premiums reacquired or redeemed on long-term debt, which are amortized over the lives of the original issuances, at AES Indiana.

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, 2025 and December 31, 2024 are related to the Utilities SBU reportable segment.

Pending Regulatory Action — AES Ohio is facing appeals from the Office of the Ohio Consumers' Council ("OCC") regarding the PUCO's decisions to approve the reversion to ESP 1 and the Smart Grid Comprehensive Settlement. The OCC is specifically seeking a refund of Rate Stabilization Charge revenues dating back to August 2021 and has appealed the final PUCO order with respect to the 2018 and 2019 SEET, which was part of the Smart Grid Comprehensive Settlement. Oral arguments regarding the ESP 1 appeal were held on April 22, 2025, and a court decision is pending. Oral arguments regarding the 2018 and 2019 SEET appeal were held on April 2, 2025. The Ohio Supreme Court reversed the PUCO's opinion and order with respect to the methodology used by the PUCO to support its findings related to the 2018 and 2019 SEET, and remanded the case to the PUCO to conduct further analysis of the SEET for those years. In the proceeding on remand, AES Ohio filed testimony proposing a refund of $1.6 million based on methodologies sponsored by its external financial consultant. The PUCO held an evidentiary hearing on this issue in October 2025, and a PUCO decision is pending.

Pending Rate Cases — In November 2025, AES Ohio filed an application with the PUCO to establish a Three-Year Rate Plan. The PUCO has set the evidentiary hearing to begin August 4, 2026, and a Commission Order is anticipated by the end of 2026.

In June 2025, AES Indiana filed an application with the IURC to increase its basic rates and charges. In October 2025, AES Indiana entered into a Stipulation and Settlement Agreement (the "Settlement Agreement") with most parties in AES Indiana's pending regulatory rate review at the IURC. This Settlement Agreement provides for updated base rates for electric services in AES Indiana's territory and is subject to, and conditioned upon, approval by the IURC. An evidentiary hearing with the IURC was held on January 28 and 29, 2026, and AES Indiana anticipates a final order from the IURC in the second quarter of 2026.

12. OBLIGATIONS

NON-RECOURSE DEBT — Non-recourse debt represents debt issued by one of our subsidiaries to be repaid solely from the subsidiary's assets. Repayments of the loans, and interest thereon, is secured solely by the capital stock, physical assets, contracts, and cash flows of that subsidiary, and the Parent Company is not otherwise liable for such debt. The following table summarizes the carrying amount and terms of non-recourse debt at our subsidiaries, excluding amounts classified as held for sale, as of the periods indicated (in millions):

NON-RECOURSE DEBT	Weighted Average Interest Rate	Maturity	December 31, 2025	December 31, 2024
Variable Rate:				
Bank loans	5.61%	2026 - 2040	$ 5,746	$ 5,132
Notes and bonds			—	105
Revolver borrowings	5.47%	2026 - 2030	1,441	3,147
Other	9.13%	2028 - 2030	20	16
Fixed Rate:				
Bank loans	6.19%	2026 - 2067	3,933	2,610
Notes and bonds	5.24%	2026 - 2055	12,203	11,737
Other [(1)]	6.71%	2026 - 2061	177	297
Unamortized (discount) premium & debt issuance (costs), net			(342)	(301)
Subtotal			$ 23,178	$ 22,743
Less: Current maturities [(2) (3)]			(2,211)	(2,670)
Noncurrent maturities [(2) (3)]			$ 20,967	$ 20,073

(1) Other fixed rate debt included $250 million related to preferred shares that included mandatory redemption features at Bellefield Equity Holdings and were therefore classified as a liability under ASC 480 as of December 31, 2024.

(2) Excludes $21 million and $18 million (current) and $714 million and $553 million (noncurrent) finance lease liabilities included in the respective non-recourse debt line items on the Consolidated Balance Sheets as of December 31, 2025 and 2024, respectively. See Note 15—*Leases* for further information.

(3) Includes $1.3 billion (current) and $10.5 billion (noncurrent) of non-recourse debt related to VIEs as of December 31, 2025.

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 designated as accounting hedges 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 $3.4 billion on non-recourse debt outstanding at December 31, 2025.

The following table summarizes the amounts due under our non-recourse debt agreements for the next five years and thereafter, as of December 31, 2025 (in millions):

December 31,	Annual Maturities
2026	$ 2,221
2027	3,554
2028	2,418
2029	2,010
2030	4,628
Thereafter	8,689
Unamortized (discount) premium & debt issuance (costs), net	(342)
Total	$ 23,178

As of December 31, 2025, AES subsidiaries had approximately $1.9 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, 2025, the following subsidiaries of the Company had significant debt issuances (in millions):

Subsidiary	Issuances [(1)]
AES Clean Energy	$ 2,456
AES Puerto Rico Solar	1,064
AES Pacifico Chile	712
AES Andes	520
AES El Salvador	384
AES Ohio	375
AES Indiana	350

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(1) These amounts do not include revolving credit facility activity at the Company's subsidiaries.

AES Pacifico Chile — During the years ended December 31, 2025 and 2024, several renewables development projects owned by AES Pacifico Chile executed project financing agreements with aggregate commitments of up to $1.7 billion to support the development and construction of wind and solar plants. As of December 31, 2025, there were $875 million in borrowings under the agreements, maturing in 2029 and 2030.

AES Ohio — In August 2025, AES Ohio issued $375 million aggregate principal of 4.55% First Mortgage Bonds due August 2030. The net proceeds from this issuance were used to repay existing indebtedness, including its unsecured $150 million term loan due in October 2025 and $195 million outstanding under its revolving credit agreement maturing in March 2030, and for general corporate purposes at AES Ohio.

AES Indiana — In August 2025, AES Indiana issued $350 million aggregate principal of 5.05% First Mortgage Bonds due August 2035. The net proceeds from this issuance were used to repay existing indebtedness, including the remaining $300 million outstanding on its unsecured term loan due in October 2025 and $30 million outstanding under its revolving credit agreement maturing in March 2030, and for general corporate purposes at AES Indiana.

In March 2024, AES Indiana issued $650 million aggregate principal of 5.70% First Mortgage Bonds due April 2054. The net proceeds from this issuance were used to repay existing indebtedness, including its unsecured $300 million term loan due in November 2024 and amounts outstanding under its $350 million revolving credit agreement maturing in December 2027, and for general corporate purposes at AES Indiana.

In March 2024, IPALCO issued $400 million aggregate principal of 5.75% senior secured notes due April 2034. In April 2024, the net proceeds from this issuance, together with cash on hand, were used to redeem the outstanding $405 million of IPALCO’s 3.70% senior secured notes due in September 2024.

AES El Salvador — In July 2025, our distribution companies operating in El Salvador entered into a credit agreement for $341 million, bearing interest at 3-month SOFR plus 3.50%, maturing in 2032. The net proceeds were used to repay existing indebtedness of $206 million, with the remainder used for dividend distributions. As a result of the refinancing, the Company recognized a loss on extinguishment of $1 million.

AES Puerto Rico Solar — The Marahu project, 70% owned by AES, is currently constructing the Salinas and Jobos renewables projects in Puerto Rico, including both solar and energy storage facilities. In July 2025, the Marahu project executed a tax credit transfer bridge loan agreement for total commitments of $230 million, at interest rates of SOFR plus a margin of 1.25% to 2.25%, maturing in April 2027. As of December 31, 2025, there was $206 million in borrowings under the agreement.

In October 2024, the Marahu project obtained a loan guarantee for $861 million from the U.S. Department of Energy and began drawing on the loan in the first quarter of 2025. As of December 31, 2025, there was $871 million, inclusive of capitalized interest, in outstanding borrowings, maturing in 2049. The remainder of the loan will be drawn upon as required to fund construction costs.

AES Andes — In March 2025, AES Andes issued $400 million aggregate principal of 6.25% senior notes due in 2032. The net proceeds from the issuance were used to redeem the remaining $228 million aggregate principal of its 6.35% junior subordinated notes due in 2079 and to repay other existing indebtedness. As a result of the latter transaction, the Company recognized a loss on extinguishment of debt of $3 million.

In March 2024, AES Andes issued $500 million aggregate principal of 6.30% senior unsecured notes due in 2029. The net proceeds from the issuance were used to purchase via tender offer $100 million and $43 million aggregate principal of its 6.35% and 5.00% notes due in 2079 and 2025, respectively, and repay other existing indebtedness.

In June 2024, AES Andes issued $530 million in Junior Subordinated Notes at 8.15%, due in 2055. The proceeds were used to repay its 7.125% notes due in 2079. As a result of the transaction, the Company recognized a loss on extinguishment of debt of $8 million.

AES Clean Energy — In December 2024, Bellefield 2 Seller, LLC executed a construction, tax equity bridge, and letter of credit financing agreement for commitments of up to $1.7 billion. As of December 31, 2025, there were $901 million in borrowings at an interest rate of 5.05% maturing in 2026 and $295 million in borrowings under the facilities at an interest rate of 5.17%, maturing in 2027.

In November 2024, AES Clean Energy, AES Clean Energy Development, and Bellefield Equity Holdings LLC ("Bellefield") entered into several key agreements with HASI, including an investment agreement under which HASI invested $250 million in Bellefield in exchange for a preferred membership interest. AES Clean Energy held a call option under which there was an unconditional obligation to redeem HASI’s preferred shares in Bellefield at the earlier of the substantial completion date or December 1, 2026, with the redemption amount consisting of the initial investment plus a 10% internal rate of return. As the call option on the preferred shares included mandatory redemption features, the instrument was classified as a liability under ASC 480 and was recorded at its fair value, which equaled the gross proceeds received of $250 million. The instrument was accreted to its redemption amount using the effective interest method. In December 2025, Bellefield 1 achieved substantial completion and the preferred shares were redeemed for $278 million, concurrently with the execution of the Bellefield 2 Equity Holdings LLC investment agreement. See Note 17—*Redeemable Stock of Subsidiaries* for further information.

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 2027. As of December 31, 2025, there was $1.2 billion in outstanding borrowings under the facilities, and the net proceeds were used primarily to repay existing indebtedness and to fund development of renewables projects.

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 in 2022 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. 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. During the year ended December 31, 2025, the Issuers issued $823 million in 6.70% notes issued due May 2050, and $346 million in 6.08% notes issued due November 2050, resulting in an aggregate principal outstanding of $3.3 billion. As a result of the notes issued in 2025 and net of repayments, AES Clean Energy Development and AES Renewable Holdings recorded, in aggregate, an increase in liabilities of $1.1 billion, resulting in an aggregate carrying amount of notes at consolidated subsidiaries of $2.5 billion as of December 31, 2025.

AES Clean Energy Development, AES Renewable Holdings, and sPower, collectively referred to as the Borrowers, executed two Credit Agreements for revolving credit facilities in 2021 and subsequent amendments in the following years for aggregate commitments of up to $4 billion with maturity dates in May and June 2028. 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 and net of repayments, AES Clean Energy Development and AES Renewable Holdings recorded, in aggregate, a decrease in liabilities of $1.3 billion in 2025, resulting in total commitments used under the revolving credit facilities, as of December 31, 2025, of $1.6 billion at consolidated subsidiaries. As of December 31, 2025, the aggregate commitments used under the revolving credit facilities for the Co-Borrowers was $1.8 billion.

AES Puerto Rico — On June 1, 2023, AES Puerto Rico was unable to pay principal and interest obligations on its Series A Bond Loans due to insufficient funds resulting from financial difficulties at the business. AES Puerto Rico signed forbearance and standstill agreements with its noteholders in July 2023 because of the insufficiency of funds to meet these obligations. On March 5, 2024, AES Puerto Rico and its noteholders executed a financial restructuring, under which the $156 million (including interest) of 6.625% Series A Bond Loans due 2026 was exchanged for $112 million of 6.625% senior secured bonds due January 2028 and $44 million of preferred shares in AES Puerto Rico. The preferred shares bear interest at 3.125% and contain an option whereby AES may call the preferred shares to be converted into 99.9% of the ordinary shares of AES Puerto Rico between December 30, 2025 and December 30, 2027, or would have the option to settle the preferred shares in cash. The noteholders also provided a $23 million bridge loan due March 2026 bearing interest at prime plus 4%, which was fully repaid in October 2025. AES Puerto Rico is required to make mandatory prepayments through cash sweeps based on excess cash (as defined in the loan agreements) available from operations on the bridge loan, senior secured bonds, and preferred shares interest. The financial restructuring was accounted for as a troubled debt restructuring in accordance with ASC 470-60, “*Troubled Debt Restructurings by Debtors”* as AES Puerto Rico was experiencing financial difficulties and the lenders granted a concession. No gain has been recognized as a result of this transaction. As of December 31, 2025, cash settlement of the preferred shares is contingent, as the amounts would not be required to be settled in cash if the option to settle the preferred shares with common shares is exercised.

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, 2025 and 2024, approximately $531 million and $147 million, respectively, of restricted cash was maintained in accordance with certain covenants of the non-recourse debt agreements. Of these amounts, $451 million and $79 million, respectively, were included within *Restricted cash* and $80 million and $68 million, respectively, were included within *Debt service reserves and other deposits* in the accompanying Consolidated Balance Sheets. As of December 31, 2025 and 2024, approximately $153 million and $155 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. Of total restricted cash and debt service reserves of $780 million, $458 million related to VIEs as of December 31, 2025.

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 $1.8 billion at December 31, 2025.

The following table summarizes the Company's subsidiary non-recourse debt in default (in millions) as of December 31, 2025. Due to the defaults, these amounts are included in the current portion of non-recourse debt:

Subsidiary	Primary Nature of Default	December 31, 2025 Debt in Default	December 31, 2025 Net Assets (Liabilities)
AES Ilumina (Puerto Rico)	Covenant	20	60

The above default is not a payment default, but is instead a technical default triggered by failure to comply with covenants or other requirements contained in the non-recourse debt documents of the subsidiary.

In November 2025, AES Puerto Rico received a full and complete waiver for all previous events of default. As such, as of December 31, 2025, the AES Puerto Rico debt balance of $143 million was not in default.

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, 2025, 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 facilities, 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 — Recourse debt represents debt that the Parent Company has an obligation to settle. This can be debt issued directly by the Parent Company or debt issued by a subsidiary under which the Parent Company has explicit commitments such as guarantees, indemnities, letters of credit, or agreements to settle if the subsidiary defaults. The following table summarizes the carrying amount and terms of recourse debt as of the periods indicated (in millions):

	Interest Rate	Final Maturity	December 31, 2025	December 31, 2024
Senior Unsecured Note	3.30%	2025	$ —	$ 900
Commercial paper outstanding borrowings		2026	79	—
Senior Unsecured Note	1.375%	2026	800	800
Drawings on revolving credit facility	SOFR + 1.80%	2027	300	—
Senior Unsecured Note	5.45%	2028	900	900
Senior Unsecured Note	3.95%	2030	700	700
Senior Unsecured Note	2.45%	2031	1,000	1,000
Senior Unsecured Note	5.80%	2032	800	—
Junior Unsecured Note	7.60%	2055	950	950
Junior Unsecured Note	6.95%	2055	500	500
Unamortized (discount) premium & debt issuance (costs), net			(45)	(46)
Subtotal			$ 5,984	$ 5,704
Less: Current maturities			(879)	(899)
Noncurrent maturities			$ 5,105	$ 4,805

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
2026	$ 879
2027	300
2028	900
2029	—
2030	700
Thereafter	3,250
Unamortized (discount) premium & debt issuance (costs), net	(45)
Total recourse debt	$ 5,984

Senior Unsecured Term Loan due December 2026 — In October 2025, the Company executed a $300 million senior unsecured term loan agreement, maturing in December 2026. As of December 31, 2025, AES had no outstanding drawings under the loan agreement.

Senior Unsecured Term Loan due December 2026 — In June 2025, the Company executed a $500 million senior unsecured term loan agreement, maturing in June 2026. In November 2025, the Company executed an amendment extending the maturity date of the loan agreement to December 2026. As of December 31, 2025, AES had no outstanding drawings under the loan agreement.

Senior Notes due 2032 — In March 2025, the Company issued $800 million aggregate principal of 5.80% senior notes due in 2032. The Company used the proceeds from this issuance to purchase via tender offer a portion of its 3.30% senior notes due in 2025. As a result of the latter transaction, the Company recognized a gain on extinguishment of debt of $2 million.

Subordinated Notes due January 2055 — In May 2024, the Company issued $950 million aggregate principal of 7.60% fixed-to-fixed reset rate subordinated notes due in January 2055. AES allocates the net proceeds from this offering to one or more eligible green projects, which may include the development or redevelopment of such projects. Pending such allocation, the net proceeds from the offering are used for general corporate purposes.

Subordinated Notes due July 2055 — In December 2024, the Company issued $500 million aggregate principal of 6.95% fixed-to-fixed reset rate subordinated notes due in July 2055. AES utilized the net proceeds from this offering to repay existing indebtedness, including borrowings under the revolving facility of its senior credit facility and commercial paper program.

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. In April 2025, the Company executed agreements to increase the maximum aggregate face amount to $1.5 billion 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 $1.8 billion in revolving credit facilities, and the Company cannot issue commercial paper in an aggregate amount exceeding the then available capacity under its revolving credit facilities. During 2025, the Company borrowed approximately $59.9 billion and repaid approximately $59.8 billion under the commercial paper program, with average daily outstanding borrowings of $709 million. As of December 31, 2025, the Company had $79 million outstanding borrowings under the commercial paper program with a weighted average interest rate of 4.10%. The Notes are classified as current.

Revolving Credit Facilities — In December 2024, AES executed a $300 million senior unsecured revolving credit facility, maturing in December 2026. The aggregate commitment under its previously existing revolving credit facility is $1.5 billion and matures in August 2027. As of December 31, 2025, AES had $300 million in outstanding drawings under its revolving credit facilities.

Recourse Debt Covenants and Guarantees — The Company's obligations under the 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 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.

Each 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.

Each 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.

SUPPLIER FINANCING ARRANGEMENTS — 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 following table shows a rollforward for outstanding supplier financing arrangements for the years ended December 31, 2025 and 2024 (in millions):

	2025	2024
Balance at January 1	$ 917	$ 974
Invoices confirmed during the year	1,380	1,737
Confirmed invoices paid during the year	(1,681)	(1,794)
Balance at December 31	$ 616	$ 917

As of December 31, 2025, these agreements ranged from less than $1 million to $51 million with a weighted average interest rate of 6.72%. Of the amounts outstanding under supplier financing arrangements as of December 31, 2025, $391 million were guaranteed, including $204 million guaranteed by the Parent Company and $187 million guaranteed by subsidiaries.

As of December 31, 2024, these agreements ranged from less than $1 million to $69 million with a weighted average interest rate of 6.83%. Of the amounts outstanding under supplier financing arrangements as of December 31, 2024, $616 million were guaranteed, including $245 million guaranteed by the Parent Company and $371 million guaranteed by subsidiaries.

13. 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, 2025 for 2026 through 2030 and thereafter as well as actual purchases under these contracts for the years ended December 31, 2025, 2024, and 2023 (in millions):

Actual purchases during the year ended December 31,	Electricity Purchase Contracts	Fuel Purchase Contracts	Other Purchase Contracts
2023	$ 1,134	$ 1,982	$ 3,181
2024	797	1,869	3,507
2025	1,023	2,132	3,441
Future commitments for the year ending December 31,			
2026	$ 819	$ 1,374	$ 4,282
2027	709	974	1,128
2028	651	581	594
2029	634	620	534
2030	637	620	209
Thereafter	4,906	3,321	897
Total	$ 8,356	$ 7,490	$ 7,644

14. CONTINGENCIES

Guarantees, Letters of Credit, and Surety Bonds — In connection with certain project financings (including tax equity transactions), acquisitions and dispositions, power purchases, EPC contracts, tax credit transfers, and other agreements, the Parent Company and its 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. In the normal course of business, the Parent Company and its subsidiaries have entered into various agreements, mainly guarantees and letters of credit, to provide financial or performance assurance to third parties on behalf of AES businesses. It is unlikely that the Parent Company or its subsidiaries would be required to perform or otherwise incur any material losses associated with guarantees of subsidiaries' or affiliates' obligations. 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 expects to fulfill within the normal course of business. Our tax equity and tax credit transfer guarantees typically consist of standard indemnifications of tax equity partners or tax credit purchasers in the event that an adverse determination arises due to a recapture event, tax controversy, or any breach by the AES project company of the representations in the shared equity agreement. The expiration dates of these guarantees vary from less than 1 year to no more than 26 years.

The following table summarizes the Parent Company's consolidated contingent contractual obligations as of December 31, 2025. 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.

Parent Company Contingent Contractual Obligations	Maximum Exposure (in millions)	Number of Agreements	Maximum Exposure Range for Each Agreement (in millions)
Guarantees and commitments [(1)]	$ 3,774	24	< $1 — 1,117
Letters of credit under bilateral agreements	220	8	< $1 — 92
Letters of credit under the unsecured credit facilities	117	7	< $1 — 60
Letters of credit under the revolving credit facilities	50	17	< $1 — 38
Total	$ 4,161	56	

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(1) Excludes payment obligation and commercial transaction arrangements entered into by the Parent Company on behalf of its consolidated subsidiaries, which relate to the Company's own future performance. See Schedule I—*Condensed Financial Information of Registrant* for additional information on guarantees issued by the Parent Company.

The following table summarizes our subsidiaries' consolidated contingent contractual obligations as of December 31, 2025. These contingent contractual obligations are issued at the subsidiary level and are non-recourse to the Parent Company. Amounts presented in the following table represent our subsidiaries' 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.

Subsidiary Contingent Contractual Obligations	Maximum Exposure (in millions)	Number of Agreements	Maximum Exposure Range for Each Agreement (in millions)
Guarantees and commitments	$ 2,532	40	< $1 — 490
Letters of credit under subsidiary credit facilities	2,114	351	< $1 — 97
Surety bonds	74	108	< $1 — 10
Total	$ 4,720	499	

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, 2025 and 2024, the Company recognized liabilities of $1 million and $2 million, respectively, for projected environmental remediation costs. These amounts are reported on the Consolidated Balance Sheets within *Accrued and other liabilities* and *Other noncurrent liabilities.* 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, 2025. Unasserted claims are not included in the range of potential losses related to environmental matters until it is probable that a claim will be asserted and there is a reasonable possibility that the outcome will be unfavorable. In aggregate, the Company estimates the range of potential losses related to environmental matters, where estimable, to be between $1 million and $5 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 $22 million and $5 million as of December 31, 2025 and 2024, 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, 2025. 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 (including but not limited to tax disputes in Brazil and El Salvador); 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 $177 million and $250 million. Included in this range is a reasonably possible legal contingency for environmental remediation costs related to Sul, a business the Company disposed of in 2016, estimated to be approximately R$15 million to R$60 million ($3 million to $11 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 24—*Income Taxes* for further information.

15. LEASES

LESSEE — The following table summarizes the amounts recognized on the Consolidated Balance Sheets related to lease asset and liability balances as of the dates indicated (in millions):

	Consolidated Balance Sheet Classification	December 31, 2025	December 31, 2024
Assets			
Right-of-use assets — finance leases	Property, plant, and equipment, net	$ 676	$ 547
Right-of-use assets — operating leases	Other noncurrent assets	369	372
Total right-of-use assets		$ 1,045	$ 919
Liabilities			
Finance lease liabilities (current)	Non-recourse debt (current liabilities)	$ 21	$ 18
Finance lease liabilities (noncurrent)	Non-recourse debt (noncurrent liabilities)	714	553
Total finance lease liabilities		735	571
Operating lease liabilities (current)	Accrued and other liabilities	36	26
Operating lease liabilities (noncurrent)	Other noncurrent liabilities	394	392
Total operating lease liabilities		430	418
Total lease liabilities		$ 1,165	$ 989

The following table summarizes supplemental balance sheet information related to leases as of the dates indicated:

Lease Term and Discount Rate	December 31, 2025	December 31, 2024
Weighted-average remaining lease term — finance leases	35 years	36 years
Weighted-average remaining lease term — operating leases	22 years	27 years
Weighted-average discount rate — finance leases	5.47 %	5.38 %
Weighted-average discount rate — operating leases	6.35 %	7.25 %

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	2025	2024
Operating lease cost	$ 54	$ 56
Finance lease cost:		
Amortization of right-of-use assets	16	13
Interest on lease liabilities	31	22
Short-term lease costs	17	18
Variable lease cost	2	—
Total lease cost	$ 120	$ 109

Operating cash outflows from operating leases included in the measurement of lease liabilities were $59 million for both the years ended December 31, 2025 and 2024, and operating cash outflows from finance leases were $21 million and $7 million for the years ended December 31, 2025 and 2024. Right-of-use assets obtained in exchange for new operating and finance lease liabilities were $50 million and $154 million, respectively, for the year ended December 31, 2025, and $129 million and $327 million, respectively, for the year ended December 31, 2024.

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, 2025 for 2026 through 2030 and thereafter (in millions):

	Maturity of Lease Liabilities	
	Finance Leases	Operating Leases
2026	$ 36	$ 50
2027	38	39
2028	39	35
2029	41	33
2030	42	33
Thereafter	1,518	653
Total	1,714	843
Less: Imputed interest	(979)	(413)
Present value of lease payments	$ 735	$ 430

LESSOR — 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,	
Operating Lease Revenue	**2025**	**2024**
Non-variable lease revenue	$ 325	$ 414
Variable lease revenue	90	61
Total lease revenue	$ 415	$ 475

The following table presents the underlying gross assets and accumulated depreciation of operating leases included in *Property, plant, and equipment, net* on the Consolidated Balance Sheets as of the dates indicated (in millions):

Property, Plant, and Equipment, Net	**December 31, 2025**	**December 31, 2024**
Gross assets	$ 1,923	$ 1,085
Less: Accumulated depreciation	(231)	(218)
Net assets	$ 1,692	$ 867

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, 2025. 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, 2025 for 2026 through 2030 and thereafter (in millions):

	Future Cash Receipts for	
	Sales-Type Leases	Operating Leases
2026	$ 63	$ 144
2027	63	65
2028	63	1
2029	63	—
2030	63	—
Thereafter	945	—
Total	$ 1,260	$ 210
Less: Imputed interest	(659)	
Present value of total lease receipts	$ 601	

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. Generally, these arrangements include both lease and non-lease elements under ASC 842, with the BESS component typically constituting a sales-type lease. Generally, losses recognized on the commencement of sales-type leases primarily relate to PPAs that contain no variable lease payments and the exclusion of the value of ITCs from the fair value of the renewable asset, which is used in the determination of the rate implicit in the lease. This results in a higher discount rate, reducing the lease receivable to an amount below the carrying value of the associated lease asset, and a resulting pre-tax loss on commencement.

The following table presents variable lease revenue, interest income, and gains (losses) on commencement of sales-type leases in which the Company is the lessor for the periods indicated (in millions):

Sales-Type Leases	Years Ended December 31, 2025	2024
Variable lease revenue	$ 2	$ 3
Interest income	26	19
Net losses on commencement of sales-types leases [1]	(231)	(67)

[1] Gains and losses are recognized in *Other income* and *Other expense*, respectively, in the Consolidated Statements of Operations. See Note 22—*Other Income and Expense* for further information.

16. 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, 2025, 2024 and 2023, costs for defined contribution plans were approximately $49 million, $47 million, and $40 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 29 active DB Plans as of December 31, 2025, 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):

	2025		2024	
	U.S.	Foreign	U.S.	Foreign
Change in projected benefit obligation:				
Benefit obligation as of January 1	$ 842	$ 71	$ 875	$ 190
Service cost	7	4	8	3
Interest cost	43	6	43	17
Plan amendments	—	—	7	—
Plan curtailments	—	(4)	—	—
Plan settlements	—	(8)	—	(3)
Benefits paid	(105)	(2)	(61)	(11)
Plan combinations	—	(2)	—	—
Divestitures	—	—	—	(99)
Actuarial loss (gain)	8	5	(30)	(6)
Effect of foreign currency exchange rate changes	—	3	—	(20)
Benefit obligation as of December 31	$ 795	$ 73	$ 842	$ 71
Change in plan assets:				
Fair value of plan assets as of January 1	$ 844	$ 14	$ 883	$ 127
Actual return on plan assets	73	3	13	7
Employer contributions	8	11	8	8
Plan settlements	—	(8)	—	(3)
Benefits paid	(105)	(2)	(60)	(11)
Divestitures	—	—	—	(100)
Effect of foreign currency exchange rate changes	—	2	—	(14)
Fair value of plan assets as of December 31	$ 820	$ 20	$ 844	$ 14
Reconciliation of funded status:				
Funded status as of December 31	$ 25	$ (53)	$ 2	$ (57)

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 dates indicated (in millions):

December 31,	**2025**		**2024**	
Amounts Recognized on the Consolidated Balance Sheets	**U.S.**	**Foreign**	**U.S.**	**Foreign**
Noncurrent assets	$ 33	$ 5	$ 25	$ 3
Accrued benefit liability—current	—	(7)	—	(8)
Accrued benefit liability—noncurrent	(8)	(51)	(23)	(52)
Net amount recognized at end of year	$ 25	$ (53)	$ 2	$ (57)

The following table summarizes the Company's U.S. and foreign accumulated benefit obligation as of the dates indicated (in millions):

December 31,	**2025**		**2024**	
	U.S.	**Foreign**	**U.S.**	**Foreign**
Accumulated benefit obligation	$ 781	$ 66	$ 829	$ 64
Information for pension plans with an accumulated benefit obligation in excess of plan assets:				
Accumulated benefit obligation	$ 26	$ 58	$ 301	$ 59
Fair value of plan assets	24	5	285	3
Information for pension plans with a projected benefit obligation in excess of plan assets:				
Projected benefit obligation	$ 291	$ 63	$ 308	$ 64
Fair value of plan assets	283	5	285	3

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,		**2025**		**2024**	
		U.S.	**Foreign**	**U.S.**	**Foreign**
Benefit Obligation:	Discount rate	5.48 %	8.59 %	5.64 %	9.74 %
	Rate of compensation increase	3.07 %	4.61 %	2.75 %	5.32 %
Periodic Benefit Cost:	Discount rate	5.64 %	9.74 % [1]	5.17 %	11.14 % [1]
	Expected long-term rate of return on plan assets	5.85 %	10.56 %	5.21 %	9.28 %
	Rate of compensation increase	2.75 %	5.32 %	2.75 %	8.01 %

(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 2025. 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, 2025 is affected by the assumptions as of that date. Pension expense for 2025 is affected by the December 31, 2024 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	$ (5)
Decrease of 1% in the discount rate	4
Increase of 1% in the long-term rate of return on plan assets	(8)
Decrease of 1% in the long-term rate of return on plan assets	8

The following table summarizes the components of the net periodic benefit cost, both domestic and foreign, for the years indicated (in millions):

December 31,	2025		2024		2023	
Components of Net Periodic Benefit Cost:	**U.S.**	**Foreign**	**U.S.**	**Foreign**	**U.S.**	**Foreign**
Service cost	$ 7	$ 4	$ 8	$ 3	$ 8	$ 4
Interest cost	43	6	43	17	47	21
Expected return on plan assets	(48)	(3)	(46)	(9)	(52)	(11)
Amortization of prior service cost	3	—	3	—	3	—
Amortization of net loss	8	1	7	—	7	—
Curtailment gain recognized	—	(3)	—	—	—	—
Settlement loss recognized	—	2	—	1	—	—
Total Net Periodic Benefit Cost	$ 13	$ 7	$ 15	$ 12	$ 13	$ 14

The following table summarizes the amounts reflected in AOCL, including AOCL attributable to noncontrolling interests, on the Consolidated Balance Sheet as of December 31, 2025, that have not yet been recognized as components of net periodic benefit cost (in millions):

December 31, 2025	Accumulated Other Comprehensive Income (Loss)	
	U.S.	**Foreign**
Prior service cost	$ (1)	$ 1
Unrecognized net actuarial loss	(13)	(6)
Total	$ (14)	$ (5)

The following table summarizes the Company's target allocation for 2025 and pension plan asset allocation, both domestic and foreign, as of the dates indicated:

		Target Allocations		Percentage of Plan Assets as of December 31, 2025		2024	
Asset Category		**U.S.**	**Foreign**	**U.S.**	**Foreign**	**U.S.**	**Foreign**
Mutual Funds	Equity securities	21.90%	—%	22.07 %	— %	22.00 %	— %
	Debt securities	78.00%	100.00%	77.37 %	100.00 %	77.00 %	100.00 %
Other		—%	—%	0.56 %	— %	1.00 %	— %
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 dates indicated (in millions):

		December 31, 2025				December 31, 2024			
U.S. Plans		**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Mutual Funds	Equity securities [(1)]	$ —	$ 181	$ —	$ 181	$ —	$ 193	$ —	$ 193
	Debt securities [(1)]	—	634	—	634	—	646	—	646
Cash and cash equivalents		5	—	—	5	5	—	—	5
Total plan assets		$ 5	$ 815	$ —	$ 820	$ 5	$ 839	$ —	$ 844

(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 minimize risk in order to closely match market conditions and near-term forecasts. As such, the asset allocation is currently fully invested in debt securities. 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 dates indicated (in millions):

Foreign Plans		December 31, 2025 Level 1	Level 2	Level 3	Total	December 31, 2024 Level 1	Level 2	Level 3	Total
Mutual Funds	Debt securities [1]	$ 20	$ —	$ —	$ 20	$ —	$ 14	$ —	$ 14
Total plan assets		$ 20	$ —	$ —	$ 20	$ —	$ 14	$ —	$ 14

[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 2026	$ 8	$ 8
Expected benefit payments for fiscal year ending:		
2026	59	8
2027	60	7
2028	60	7
2029	60	8
2030	60	11
2031 - 2035	297	56

Collective Bargaining Agreements — As of December 31, 2025, approximately 31% 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 2026 to 2027. In addition, certain employees in non-U.S. locations were subject to collective bargaining agreements, representing approximately 48% of the non-U.S. workforce. As of December 31, 2025, approximately 25% of our U.S. and non-U.S. workforce is part of bargaining agreements expiring on or before December 31, 2026.

17. REDEEMABLE STOCK OF SUBSIDIARIES

The following table is a reconciliation of changes in redeemable stock of subsidiaries (in millions):

December 31,	2025	2024	2023
Balance at the beginning of the period	$ 938	$ 1,464	$ 1,321
Net loss	(158)	(86)	(59)
Other comprehensive income	—	73	1
Adjustments to redemption value	10	—	—
Reclassification of redeemable stock of subsidiaries to noncontrolling interests	(180)	(736)	—
Disposition of business interests	—	(18)	—
Distributions to holders of redeemable stock of subsidiaries	(527)	(61)	(62)
Contributions from holders of redeemable stock of subsidiaries	644	105	163
Sales of redeemable stock of subsidiaries	1,132	197	100
Issuance of preferred shares in subsidiaries	965	—	—
Balance at the end of the period	$ 2,824	$ 938	$ 1,464

The following table summarizes the Company's redeemable stock of subsidiaries balances as of the periods indicated (in millions):

December 31,	2025	2024
IPALCO common stock	$ 1,003	$ 835
AES Ohio common stock	595	—
AES Global Insurance preferred stock	472	—
Bellefield 2 Equity Holdings preferred stock	249	—
AES Clean Energy tax equity partnerships	228	65
AES DevCo HoldCo preferred stock	199	—
Desarrollos Renovables preferred stock	78	—
AES Indiana Pike County BESS tax equity partnership	—	38
Total redeemable stock of subsidiaries	$ 2,824	$ 938

Bellefield 2 Equity Holdings — In December 2025, the Company entered into several key agreements with HASI, including an investment agreement under which HASI invested $250 million in the Bellefield 2 renewables development project in exchange for a preferred membership interest. The agreement contains certain redemption features that may require future redemption of the preferred membership interest and are not solely in AES' control. As a result, the noncontrolling ownership interest is considered temporary equity, resulting in an increase to *Redeemable stock of subsidiaries* of $249 million, net of transaction costs. The Company has concluded it is

probable the Bellefield 2 project will generate sufficient cash upon substantial completion to require distributions, absent members' consent, to be made to the preferred member of an amount that would redeem the instrument. Therefore, the noncontrolling ownership interest is probable of becoming redeemable. As of December 31, 2025, the carrying value of the noncontrolling interest approximates redemption value, therefore no adjustment to the carrying value was necessary. Bellefield 2 Equity Holdings is reported in the Renewables SBU reportable segment.

AES DevCo HoldCo, LLC — In December 2025, the Company entered into several key agreements with HASI, including an investment agreement under which HASI invested $200 million in the Buffalo Gap wind repowering project in exchange for a preferred membership interest. The agreement contains certain redemption features that may require future redemption of the preferred membership interest and are not solely in AES' control. As a result, the noncontrolling ownership interest is considered temporary equity, resulting in an increase to *Redeemable stock of subsidiaries* of $199 million, net of transaction costs. The Company has concluded it is probable the Buffalo Gap wind repowering project will generate sufficient cash upon substantial completion to require distributions, absent members' consent, to be made to the preferred member of an amount that would redeem the instrument. Therefore, the noncontrolling ownership interest is probable of becoming redeemable. As of December 31, 2025, the carrying value of the noncontrolling interest approximates redemption value, therefore no adjustment to the carrying value was necessary. AES DevCo Holdco, LLC is reported in the Renewables SBU reportable segment.

AES Indiana Petersburg Energy Center — In October 2025, AES Indiana sold a noncontrolling interest in the Petersburg Energy Center energy storage project to a tax equity investor, resulting in a $53 million increase to *Redeemable stock of subsidiaries*. The redemption feature of the tax equity partnership agreement was contingent upon the underlying assets being placed in service by a guaranteed date. In November 2025, the Petersburg Energy Center project was placed in service, resulting in the expiration of the redemption feature. As a result, the noncontrolling ownership interest of $53 million was reclassified from *Redeemable stock of subsidiaries* to *Noncontrolling interests* on the Consolidated Balance Sheets. AES Indiana is reported in the Utilities SBU reportable segment.

Desarrollos Renovables — In August 2025, AES Pacifico, our wholly-owned subsidiary in Chile, executed a renewables partnership agreement with Global Infrastructure Management, LLC ("GIP") for the sale of a 49% ownership interest in AES Desarrollos Renovables SpA ("Desarrollos Renovables") for total consideration of $77 million. At the execution date, AES Pacifico contributed the Andes Solar III and Punta del Sol renewables development projects to Desarrollos Renovables. Under its renewables partnership agreement with GIP, AES Pacifico will contribute a specified pipeline of renewables development projects to Desarrollos Renovables, and GIP may make additional contributions to maintain its 49% ownership interest. AES Pacifico retained a 51% ownership interest in Desarrollos Renovables. The agreement contains certain redemption features that expire upon certain agreed-upon project milestones being achieved. While not currently in effect, the redemption features are not solely in AES' control. As a result, the noncontrolling ownership interest is considered temporary equity. The Company has concluded it is probable that these projects will reach the specified milestones. Therefore, the noncontrolling ownership interests are not probable of becoming redeemable and subsequent adjustments to the carrying value were not required. Desarrollos Renovables is reported in the Renewables SBU reportable segment.

AES Global Insurance — In April 2025, the Company sold minority interests in AES Global Insurance Company, LLC ("AGIC"), AES' captive insurance company, and AGIC Holdings, LLC (together with AGIC, the "AGIC Companies") in exchange for $450 million in total proceeds for Class B units representing 17.5% and 18.0%, respectively, of each entity's total outstanding units, for a combined ownership (directly and indirectly) of AGIC's total outstanding units of 32.4% by the Class B Member. The Company continues to own Class A units for the remaining economic interest in the AGIC Companies. The Class B units provide for target distribution amounts for the Class B Member, with a call option for AES for years 2030 through 2035 to redeem these units at pre-agreed redemption prices.

As the agreement contains certain redemption features that may require future redemption of the Class B units and are not solely in AES' control, the noncontrolling interest is considered temporary equity. The contractual target rate of return increases the redemption price on the Class B units and the annual distributions reduce the applicable redemption price. Annual dividends are subject to regulatory and the AGIC Companies Boards' approval. Through March 31, 2045, the AGIC Companies Boards will approve distributions to the Class B Member to the extent that there is sufficient cash generated from operations each annual period. After March 31, 2045, all dividends are discretionary if the Class B units remain outstanding. It is probable that the AGIC Companies' performance will generate sufficient cash to require distributions to be made to the Class B Member of an amount that would redeem the instrument after the call option period. Therefore, as of December 31, 2025, the noncontrolling interest is probable of becoming redeemable and the carrying value of the Class B units will be adjusted to equal the redemption value each reporting period. As of December 31, 2025, the redemption value of the noncontrolling ownership interest of $472 million exceeded the carrying value; as such, an adjustment of $10 million was recorded to *Redeemable stock of subsidiaries* on the Consolidated Balance Sheets to increase the carrying value to the Class B units' redemption value. The AGIC Companies are reported in Corporate and Other.

As part of the transaction, it is required that either (i) the AGIC Companies achieve a minimum distribution target to the Class B Member ranging from $146 million to $199 million over pre-defined periods of time ranging from three to five years (the "distribution period") or (ii) AGIC achieves an average cash basis quarterly net income threshold for the period comprising the relevant distribution period and the four quarters immediately prior to the start of such distribution period. AES can make disproportionate distributions to the Class B Member to meet the minimum distribution target for the distribution period. If, at the end of a distribution period, (1) such cash basis net income threshold is not met and (2) the minimum distribution target for such distribution period is not achieved, AES would be required to address the shortfall by issuing AES common stock ("Shortfall Stock") to AGIC for the net difference between actual and targeted distributions. Distributions of cash from the sale of Shortfall Stock are subject to regulatory approval and at the discretion of AES.

AES Ohio — In April 2025, DPL sold an indirect equity interest in AES Ohio of approximately 30% to Astrid Holdings LP, a wholly-owned subsidiary of CDPQ, for total proceeds of approximately $544 million, resulting in an increase to *Redeemable stock of subsidiaries* of $538 million, net of transaction costs. The Company also recognized an increase to additional paid-in capital and a reduction to retained earnings of $188 million for the excess of the fair value of the shares over the share of the net assets sold. The shareholders' agreements contain certain redemption features that, while not currently in effect, are not solely in AES' control. As a result, the noncontrolling ownership interest is considered temporary equity. The Company has concluded that the likelihood of an event that would allow CDPQ to redeem its interest under the terms of the shareholders' agreements is not probable, but would require redemption at fair value. Therefore, as of December 31, 2025, the noncontrolling ownership interest is not probable of becoming redeemable and subsequent adjustments to the carrying value were not required. AES Ohio is reported in the Utilities SBU reportable segment.

AES Clean 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, which vary over the life of the projects. The substance of such arrangements is that of a preferred structure, whereby tax equity investors are granted preferential returns in the form of significant earnings and tax allocations from the partnership, until a specified internal rate of return is achieved.

In some cases, these agreements contain certain partnership rights, though not currently in effect, which may enable the tax equity investor to exit in the future. As a result, the noncontrolling ownership interest is considered temporary equity. Some of these tax equity partnership agreements have redemption features dependent upon the passage of time, therefore the noncontrolling ownership interests are probable of becoming redeemable. As of December 31, 2025, the carrying values of these noncontrolling ownership interests exceeded the redemption values, therefore no adjustments to the carrying values were necessary. Certain other tax equity partnership agreements have redemption features that expire upon certain agreed-upon project milestones being achieved. The Company has concluded it is probable that these projects will reach the specified milestones, therefore the noncontrolling ownership interests are not probable of becoming redeemable and subsequent adjustments to the carrying value were not required.

In 2025, 2024, and 2023, AES Clean Energy, through multiple transactions, sold noncontrolling interests in project companies to tax equity investors, resulting in increases to *Redeemable stock of subsidiaries* of $541 million, $159 million, and $100 million, respectively, net of transaction costs. During 2025 and 2024, certain renewables development projects with redemption features were placed in service, resulting in the expiration of the redemption features. As a result, noncontrolling ownership interests of $88 million and $159 million were reclassified from *Redeemable stock of subsidiaries* to *Noncontrolling interests* on the Consolidated Balance Sheets. AES Clean Energy is reported in the Renewables SBU reportable segment.

AES Indiana Pike County BESS — In December 2024, AES Indiana sold a noncontrolling interest in the Pike County energy storage project to a tax equity investor, resulting in a $38 million increase to *Redeemable stock of subsidiaries*. The redemption feature of the tax equity partnership agreement was contingent upon the underlying assets being placed in service by a guaranteed date. In March 2025, the Pike County BESS project was placed in service, resulting in the expiration of the redemption feature. As a result, the noncontrolling ownership interest of $38 million was reclassified from *Redeemable stock of subsidiaries* to *Noncontrolling interests* on the Consolidated Balance Sheets. AES Indiana is reported in the Utilities SBU reportable segment.

IPALCO — The shareholder agreement with CDPQ contains certain redemption features that, while not currently in effect, are not solely in AES' control. As a result, the noncontrolling ownership interest in IPALCO is considered temporary equity. 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, but would require redemption at fair value. 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 Clean Energy Development — As part of the formation of AES Clean Energy Development in February 2021, the noncontrolling interest partner received certain partnership rights that would enable them to exit in the future. As a result, the noncontrolling ownership interest was considered temporary equity. In May 2024, these redemption features expired without being exercised and the noncontrolling ownership interest of $577 million was reclassified from *Redeemable stock of subsidiaries* to *Noncontrolling interests* on the Consolidated Balance Sheets. AES Clean Energy Development is reported in the Renewables SBU reportable segment.

18. 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 had 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 represented mandatorily convertible preferred stock. Accordingly, the shares associated with the combined instrument were 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 renewables businesses, U.S. utility businesses, LNG infrastructure, and for other developments determined by management.

The Series A Preferred Stock did not bear any dividends and the liquidation preference of the convertible preferred stock did not accrete. The Series A Preferred Stock had no maturity date and would remain outstanding unless converted by holders or redeemed by the Company. Holders of the preferred shares had limited voting rights. The Series A Preferred Stock was pledged as collateral to support holders’ purchase obligations under the 2024 Purchase Contracts, which 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 could not exceed the maximum settlement rate and was determined over a market value averaging period preceding February 15, 2024. 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. On February 15, 2024, the Series A Preferred Stock was tendered to satisfy the 2024 Purchase Contract’s settlement price and the Corporate Units were converted into shares of the Company’s common stock at the maximum settlement rate of 3.8859, equivalent to a reference price of $25.73. The Series A Preferred Stock was canceled and 40,531,845 shares of AES common stock were issued 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. The final Contract Adjustment Payments were made on February 15, 2024.

Equity Transactions with Noncontrolling Interests

AES Clean 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, which vary over the life of the projects. The substance of such arrangements is that of a preferred structure, whereby tax equity investors are granted preferential returns in the form of significant earnings and tax allocations from the partnership, until a specified internal rate of return is achieved.

During 2025, 2024, and 2023, 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	2025	2024	2023
AES Clean Energy Development	$ 502	$ 603	$ 1,039
AES Renewable Holdings	209	263	124

During the third quarter of 2025, AES Renewable Holdings completed buyouts of tax equity partners at Buffalo Gap I, Buffalo Gap II, and Buffalo Gap III, resulting in a decrease to NCI of $28 million and a decrease to additional paid-in capital of $42 million. 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.

AES Clean Energy Development — In December 2025, the Company completed a non-cash conversion of outstanding loans from both the AES member and noncontrolling interest partner in AES Clean Energy Development. The loan balances were converted to capital contributions on a pro-rata basis relative to their ownership percentages. The conversion resulted in a $422 million increase to NCI. AES Clean Energy Development is reported in the Renewables SBU reportable segment.

AES Indiana Petersburg Energy Center — In November 2025, as a result of the Petersburg Energy Center energy storage project being placed in service, the noncontrolling ownership interest of $53 million was reclassified from *Redeemable stock of subsidiaries* to *Noncontrolling interests* on the Consolidated Balance Sheets. See Note 17—*Redeemable Stock of Subsidiaries* for further information. Subsequently, AES Indiana sold additional noncontrolling interests to the tax equity investor, resulting in a $90 million increase in NCI. AES Indiana is reported in the Utilities SBU reportable segment.

Cochrane — In May 2025, the Company acquired the remaining 40% of the common shares in Empresa Electrica Cochrane SpA (“Cochrane”), a coal-fired plant in Chile, from a third-party investor for $89 million, increasing AES’ ownership in Cochrane to 96.7%. This transaction resulted in a $40 million decrease in Parent Company Stockholder’s Equity due to a decrease in additional paid-in-capital of $23 million and a reclassification of accumulated other comprehensive losses from NCI to AOCL of $17 million. The preferred shares in Cochrane, previously issued by AES Andes in September 2020, remain outstanding. Under the terms of the operating agreement, preferred shareholders have the preferential right to receive distributions from the earnings or available distributable capital of Cochrane until reaching their original investment plus a specified rate of return. Cochrane is reported in the Energy Infrastructure SBU reportable segment.

AES Indiana Pike County BESS — In March 2025, as a result of the Pike County BESS project being placed in service, the noncontrolling ownership interest of $38 million was reclassified from *Redeemable stock of subsidiaries* to *Noncontrolling interests* on the Consolidated Balance Sheets. See Note 17—*Redeemable Stock of Subsidiaries* for further information. Subsequently, AES Indiana sold additional noncontrolling interests to the tax equity investor, resulting in a $150 million increase to NCI. AES Indiana is reported in the Utilities SBU reportable segment.

AES Brasiliana — In October 2024, prior to and separate from the sale of AES Brasil, the Company completed the acquisition of the remaining noncontrolling ownership interest in AES Brasiliana Holdings Ltda. ("AES Brasiliana") for a nominal amount. This transaction resulted in a $304 million decrease in Parent Company Stockholders' Equity due to a decrease in additional paid-in-capital of $802 million, offset by the reclassification of cumulative translation adjustments from NCI to AOCL of $498 million. As the Company maintained control after the acquisition, AES Brasiliana continues to be consolidated by the Company within the Renewables SBU reportable segment.

Chile Renovables — Under its renewables partnership agreement with Global Infrastructure Management, LLC ("GIP"), AES Andes will contribute a specified pipeline of renewables development projects to Chile Renovables as the projects reach commercial operations, and GIP may make additional contributions to maintain its 49% ownership interest. During 2025, 2024, and 2023, AES Andes completed the sale 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
Campo Lindo	September 2023	50	59	(9)
Bolero	November 2023	58	57	1
Andes Solar 2b	December 2023	156	145	11
Mesamávida	February 2024	40	51	(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 an additional pipeline of renewables projects. Under the terms of the operating agreement, GIP will receive an escalating specified internal rate of return up until the point the projects reach commercial operations. 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. In the fourth quarter of 2024, the San Matias, Andes Solar IV, and Andes Solar 2b Expansion projects reached commercial operations. The preferred shares were converted to common stock and GIP made additional contributions of $77 million, resulting in an increase to NCI of $74 million and an increase to additional paid-in capital of $3 million. In February 2025, the Andes Solar 2a BESS project reached commercial operations. The preferred shares were converted to common stock and GIP made additional contributions of $14 million, resulting in an increase to NCI of $17 million and a decrease to additional paid-in capital of $3 million. In December 2025, Chile Renovables issued an additional $16 million of preferred shares to GIP, the proceeds of which will be used to fund the development of the Bolero BESS project.

As the Company maintained control after each of these transactions, Chile Renovables continues to be consolidated by the Company within the Renewables SBU reportable segment.

AES Puerto Rico Solar — In May 2024, AES CFE Holding II entered into an agreement for the sale of a 30% ownership interest in the Marahu project for $35 million, resulting in an increase to NCI. As the Company maintained control after this transaction, AES Puerto Rico Solar continues to be consolidated by the Company within the Renewables SBU reportable segment.

AES Indiana Hardy Hills Solar — 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. In May 2024, the project reached commercial operations and AES Indiana received an additional $47 million from the tax equity investor. AES Indiana is reported in the Utilities 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 continued to be consolidated by the Company. In June 2025, the Company completed the sale of 50% of its interests in Dominican Republic Renewables, which includes Bayasol, Santanasol, and Agua Clara. The transaction resulted in the deconsolidation of Dominican Republic Renewables, which is now accounted for as an equity method investment. See Note 9—*Investments in and Advances to Affiliates* and Note 25—*Held-for-Sale and Dispositions* for further information. Andres and Los Mina are reported in the Energy Infrastructure SBU reportable segment and the Dominican Republic Renewables equity method investment is reported in the Renewables SBU reportable segment.

Colon — In December 2023, the Company completed the sale of 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. Under the terms of the operating agreement, HASI will receive cash distributions disproportionate to its ownership interest in OpCo 1 until a specified internal rate of return is reached. 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 9—*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.

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):

Year Ended December 31,	**2025**	**2024**	**2023**
Net income attributable to The AES Corporation	$ 910	$ 1,679	$ 249
Transfers (to) from noncontrolling interest:			
Increase (decrease) in The AES Corporation's paid-in capital for sale of subsidiary shares	170	(19)	85
Additional paid-in capital transferred to redeemable stock of subsidiaries [1]	(188)	—	—
Increase (decrease) in The AES Corporation's paid-in capital for acquisition of subsidiary shares	(52)	(802)	24
Net transfers (to) from noncontrolling interest	(70)	(821)	109
Change from net income (loss) attributable to The AES Corporation and transfers (to) from noncontrolling interests	$ 840	$ 858	$ 358

(1) See Note 17—*Redeemable Stock of Subsidiaries* for further information on increase in paid-in capital transferred to redeemable stock of subsidiaries.

Accumulated Other Comprehensive Loss — The changes in AOCL by component, net of tax and NCI, for the periods indicated were as follows (in millions):

	Foreign currency translation adjustments, net	**Change in fair value of derivatives, net**	**Pension adjustments, net**	**Change in fair value option liabilities, net**	**Total**
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)
Other comprehensive income (loss) before reclassifications	(159)	315	(5)	3	154
Amount reclassified to earnings	71	18	7	—	96
Other comprehensive income (loss)	(88)	333	2	3	250
Reclassification from NCI due to share repurchases	498	—	—	—	498
Balance at December 31, 2024	$ (1,282)	$ 537	$ (24)	$ 3	$ (766)
Other comprehensive income (loss) before reclassifications	114	(35)	(1)	—	78
Amount reclassified to earnings	—	(2)	1	—	(1)
Other comprehensive income (loss)	114	(37)	—	—	77
Reclassification from NCI due to share sales and repurchases	—	(17)	8	—	(9)
Balance at December 31, 2025	$ (1,168)	$ 483	$ (16)	$ 3	$ (698)

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	Year Ended December 31, 2025	2024	2023
Foreign currency translation adjustments, net				
	Gain (loss) on disposal and sale of business interests	$ —	$ (649)	$ —
	Net income (loss) attributable to The AES Corporation	$ —	$ (649)	$ —
	Less: Net income (loss) attributable to The AES Corporation—reclassified out of NCI and redeemable stock of subsidiaries	—	578	—
	Net income (loss) attributable to The AES Corporation—reclassified out of AOCL	$ —	$ (71)	$ —
Change in fair value of derivatives, net				
	Non-regulated revenue	$ —	$ —	$ (8)
	Non-regulated cost of sales	(8)	(2)	(3)
	Interest expense	8	(32)	17
	Gain (loss) on disposal and sale of business interests	—	(8)	33
	Foreign currency transaction gains (losses)	7	2	(3)
	Income (loss) from continuing operations before taxes and equity in earnings of affiliates	7	(40)	36
	Income tax benefit (expense)	(11)	8	9
	Net equity in losses of affiliates	2	2	28
	Net income (loss)	(2)	(30)	73
	Less: Net loss attributable to noncontrolling interests and redeemable stock of subsidiaries	4	8	(21)
	Net income (loss) attributable to The AES Corporation	$ 2	$ (22)	$ 52
	Less: Net income (loss) attributable to The AES Corporation—reclassified out of NCI	—	4	—
	Net income (loss) attributable to The AES Corporation—reclassified out of AOCL	$ 2	$ (18)	$ 52
Pension adjustments, net				
	Other expense	(1)	(2)	—
	Gain (loss) on disposal and sale of business interests	—	(14)	—
	Income (loss) from continuing operations before taxes and equity in earnings of affiliates	(1)	(16)	—
	Income tax benefit (expense)	—	1	—
	Net income (loss)	(1)	(15)	—
	Net income (loss) attributable to The AES Corporation	$ (1)	$ (15)	$ —
	Less: Net income (loss) attributable to The AES Corporation—reclassified out of NCI	—	8	—
	Net income (loss) attributable to The AES Corporation—reclassified out of AOCL	$ (1)	$ (7)	$ —
Total reclassifications out of AOCL for the period, net of income tax and noncontrolling interests		$ 1	$ (96)	$ 52

Common Stock Dividends — The Parent Company paid dividends of $0.17595 per outstanding share to its common stockholders during the first, second, third, and fourth quarters of 2025 for dividends declared in December 2024, February 2025, July 2025, and October 2025, respectively.

On December 4, 2025, the Board of Directors declared a quarterly common stock dividend of $0.17595 per share payable on February 13, 2026 to shareholders of record at the close of business on January 30, 2026.

Stock Repurchase Program — No shares were repurchased in 2025 under the Stock Repurchase Program. The cumulative repurchases from the commencement of the Stock Repurchase Program in July 2010 through December 31, 2025 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, 2025, $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 147,634,762 and 148,635,718 shares were held as treasury stock at December 31, 2025 and December 31, 2024, 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.

19. 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. The management reporting structure is composed of four SBUs, mainly organized by technology, led by our Chief Executive Officer, who is our Chief Operating Decision Maker. 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. In March 2026, the Company announced changes in its internal management structure, including a change in its President. The Company is currently evaluating the impact, if any, these changes may have on its segment reporting structure in future periods; however, no changes in the Company's operating or reportable segments are reflected in the accompanying financial statements.

- *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
- *New Energy Technologies* — Investments in Fluence, Maximo, and other new and innovative energy technology businesses.

Prior to the first quarter of 2025, our businesses in Chile (which had a mix of generation sources, including renewables, that were pooled to service our existing PPAs initially entered into for sale of the output of the coal plants) were reported in the Energy Infrastructure SBU. After the sale or disconnection of a significant portion of AES Andes' coal plants and the expiration of its coal-indexed contracts with regulated customers at the end of 2024, the results of our businesses in Chile, excluding the two remaining coal plants, are now reported as part of the Renewables SBU in financial information regularly reviewed by the Chief Operating Decision Maker. The results of the two remaining coal plants in Chile, Angamos and Cochrane, remain within the Energy Infrastructure SBU. As the composition of the segments changed in the first quarter of 2025, the segment information for prior comparative periods has been retrospectively revised to reflect AES Andes' renewables partnership with GIP, Chile Renovables, which is separable from the rest of the AES Andes portfolio, as part of the Renewables SBU. We determined that there was no separately identifiable financial information for the other renewables in the AES Andes portfolio as they were servicing the same coal-indexed PPAs as the coal facilities prior to 2025; therefore, the rest of the renewables portfolio at AES Andes is presented within the Energy Infrastructure SBU in the 2024 and 2023 segment information presented. Revenue and Adjusted EBITDA for AES Andes that are presented within the Energy Infrastructure SBU in historical periods and within the Renewables SBU in 2025 were \$900 million and \$68 million, respectively, during the year ended December 31, 2025.

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, transmit, distribute, 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 AES Global Insurance Company, LLC ("AGIC"), AES' captive 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.

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, amortization, and accretion of AROs, adjusted for the impact of NCI and interest, taxes, depreciation, amortization, and accretion of AROs 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 pertaining to derivative transactions, equity securities, and financial assets and liabilities measured using the fair value option; (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 or troubled debt restructuring; and (f) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts.

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. The Chief Operating Decision Maker uses Adjusted EBITDA to allocate resources and capital for each segment in the annual budget and forecasting process, including making decisions on where to reinvest profits to support segment growth. On a monthly basis, the Chief Operating Decision Maker reviews variances in budget versus actual Adjusted EBITDA and monitors changes in forecasted Adjusted EBITDA to assess the underlying operating performance and analyze risks and opportunities at each segment.

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):

	Year Ended December 31, 2025				
	Renewables SBU	**Utilities SBU**	**Energy Infrastructure SBU**	**New Energy Technologies SBU**	**Total**
Revenue	$ 2,913	$ 4,122	$ 5,402	$ 1	$ 12,438
Corporate and other					149
Eliminations					(354)
Total Revenue					$ 12,233
Less:					
Total cost of sales excluding depreciation, amortization, and accretion of AROs (1)	1,830	2,963	4,159	11	
Other segment items (2)	151	296	113	25	
Segment Adjusted EBITDA	$ 932	$ 863	$ 1,130	$ (35)	$ 2,890
Reconciliation to income from continuing operations before taxes					
Corporate and other					(29)
Eliminations					10
Interest expense					(1,407)
Interest income					287
Depreciation, amortization, and accretion of AROs					(1,457)
Adjusted for:					
Noncontrolling interests and redeemable stock of subsidiaries					824
Income tax expense, interest expense, and depreciation, amortization, and accretion of AROs from equity affiliates					(171)
Interest income recognized under service concession arrangements					(58)
Unrealized derivatives, equity securities, and financial assets and liabilities losses					(120)
Unrealized foreign currency losses					(26)
Disposition/acquisition losses					(244)
Impairment losses					(369)
Loss on extinguishment of debt and troubled debt restructuring					(21)
Restructuring costs					(89)
Income from continuing operations before taxes					$ 20

(1) Segment-level total cost of sales excluding depreciation, amortization, and accretion of AROs is considered regularly provided to the chief operating decision maker. Total cost of sales excluding depreciation, amortization, and accretion of AROs includes items such as fuel cost, electricity purchases, transmission charges, supplies, salaries and wages, consulting costs, IT costs, market fees, insurance, and lease expense.

(2) Other segment items for each reportable segment includes:

Renewables SBU — business development costs, miscellaneous gains and losses in *Other income* and *Other expense*, realized foreign currency gains and losses, earnings from equity affiliates, and adjustment for noncontrolling interest expense.

Utilities SBU — miscellaneous gains and losses in *Other income* and *Other expense*, earnings from equity affiliates, and adjustment for noncontrolling interest expense.

Energy Infrastructure SBU — service concession interest income, business development costs, miscellaneous gains and losses in *Other income* and *Other expense*, realized foreign currency gains and losses, earnings from equity affiliates, and adjustment for noncontrolling interest expense.

New Energy Technologies SBU — business development costs, earnings from equity affiliates, and miscellaneous gains and losses in *Other income* and *Other expense*.

	Year Ended December 31, 2024				
	Renewables SBU	Utilities SBU	Energy Infrastructure SBU	New Energy Technologies SBU	Total
Revenue	$ 2,617	$ 3,608	$ 6,207	$ 1	$ 12,433
Corporate and other					162
Eliminations					(317)
Total Revenue					$ 12,278
Less:					
Total cost of sales excluding depreciation, amortization, and accretion of AROs [1]	1,772	2,607	4,624	8	
Other segment items [2]	233	209	277	31	
Segment Adjusted EBITDA	$ 612	$ 792	$ 1,306	$ (38)	$ 2,672
Reconciliation to income from continuing operations before taxes					
Corporate and other					11
Eliminations					(44)
Interest expense					(1,485)
Interest income					381
Depreciation, amortization, and accretion of AROs					(1,264)
Adjusted for:					
Noncontrolling interests and redeemable stock of subsidiaries					734
Income tax expense, interest expense, and depreciation, amortization, and accretion of AROs from equity affiliates					(136)
Interest income recognized under service concession arrangements					(65)
Unrealized derivatives, equity securities, and financial assets and liabilities gains					94
Unrealized foreign currency losses					(16)
Disposition/acquisition gains					323
Impairment losses					(280)
Loss on extinguishment of debt and troubled debt restructuring					(57)
Income from continuing operations before taxes					$ 868

(1) Segment-level total cost of sales excluding depreciation, amortization, and accretion of AROs is considered regularly provided to the chief operating decision maker. Total cost of sales excluding depreciation, amortization, and accretion of AROs includes items such as fuel cost, electricity purchases, transmission charges, supplies, salaries and wages, consulting costs, IT costs, market fees, insurance, and lease expense.

(2) Other segment items for each reportable segment includes:

Renewables SBU — business development costs, miscellaneous gains and losses in *Other income* and *Other expense*, realized foreign currency gains and losses, earnings from equity affiliates, and adjustment for noncontrolling interest expense.

Utilities SBU — miscellaneous gains and losses in *Other income* and *Other expense*, earnings from equity affiliates, and adjustment for noncontrolling interest expense.

Energy Infrastructure SBU — service concession interest income, business development costs, miscellaneous gains and losses in *Other income* and *Other expense*, realized foreign currency gains and losses, earnings from equity affiliates, and adjustment for noncontrolling interest expense.

New Energy Technologies SBU — earnings from equity affiliates, and miscellaneous gains and losses in *Other income* and *Other expense*.

	Year Ended December 31, 2023				
	Renewables SBU	Utilities SBU	Energy Infrastructure SBU	New Energy Technologies SBU	Total
Revenue	$ 2,416	$ 3,495	$ 6,805	$ 76	$ 12,792
Corporate and other					138
Eliminations					(262)
Total Revenue					$ 12,668
Less:					
Total cost of sales excluding depreciation, amortization, and accretion of AROs [1]	1,520	2,662	5,052	84	
Other segment items [2]	199	155	258	54	
Segment Adjusted EBITDA	$ 697	$ 678	$ 1,495	$ (62)	$ 2,808
Reconciliation to income from continuing operations before taxes					
Corporate and other					22
Eliminations					(2)
Interest expense					(1,319)
Interest income					551
Depreciation, amortization, and accretion of AROs					(1,147)
Adjusted for:					
Noncontrolling interests and redeemable stock of subsidiaries					556
Income tax expense, interest expense, and depreciation, amortization, and accretion of AROs from equity affiliates					(131)
Interest income recognized under service concession arrangements					(71)
Unrealized derivatives, equity securities, and financial assets and liabilities losses					(34)
Unrealized foreign currency losses					(301)
Disposition/acquisition gains					79
Impairment losses					(877)
Loss on extinguishment of debt and troubled debt restructuring					(62)
Income from continuing operations before taxes					$ 72

(1) Segment-level total cost of sales excluding depreciation, amortization, and accretion of AROs is considered regularly provided to the chief operating decision maker. Total cost of sales excluding depreciation, amortization, and accretion of AROs includes items such as fuel cost, electricity purchases, transmission charges, supplies, salaries and wages, consulting costs, IT costs, market fees, insurance, and lease expense.

(2) Other segment items for each reportable segment includes:

Renewables SBU — business development costs, miscellaneous gains and losses in *Other income* and *Other expense*, realized foreign currency gains and losses, earnings from equity affiliates, and adjustment for noncontrolling interest expense.

Utilities SBU — miscellaneous gains and losses in *Other income* and *Other expense*, earnings from equity affiliates, and adjustment for noncontrolling interest expense.

Energy Infrastructure SBU — service concession interest income, business development costs, miscellaneous gains and losses in *Other income* and *Other expense*, realized foreign currency gains and losses, earnings from equity affiliates, and adjustment for noncontrolling interest expense.

New Energy Technologies SBU — earnings from equity affiliates, and miscellaneous gains and losses in *Other income* and *Other expense*.

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 2025	Long-Lived Assets 2024	Long-Lived Assets 2023
Renewables SBU	$ 23,945	$ 19,151	$ 17,300
Utilities SBU	9,464	8,535	7,166
Energy Infrastructure SBU	4,726	5,805	5,848
New Energy Technologies SBU	23	22	14
Corporate and Other	29	25	10
Long-Lived Assets	38,187	33,538	30,338
Current assets	6,502	6,831	6,649
Investments in and advances to affiliates	1,004	1,124	941
Debt service reserves and other deposits	89	78	194
Goodwill	342	345	348
Other intangible assets	2,040	1,947	2,243
Deferred income taxes	397	365	396
Loan receivable	755	—	—
Other noncurrent assets, excluding right-of-use assets for operating leases	2,452	2,545	2,879
Noncurrent held-for-sale assets	—	633	811
Total Assets	$ 51,768	$ 47,406	$ 44,799

Year Ended December 31,	Depreciation, Amortization, and Accretion of AROs 2025	2024	2023	Capital Expenditures 2025	2024	2023
Renewables SBU	$ 584	$ 449	$ 374	$ 4,586	$ 5,481	$ 5,971
Utilities SBU	524	458	400	1,261	1,570	1,374
Energy Infrastructure SBU	342	349	363	112	422	373
New Energy Technologies SBU	2	1	1	7	11	5
Corporate and Other	5	7	9	16	35	10
Total	$ 1,457	$ 1,264	$ 1,147	$ 5,982	$ 7,519	$ 7,733

Year Ended December 31,	Interest Income 2025	2024	2023	Interest Expense 2025	2024	2023	Net Equity in Earnings (Losses) of Affiliates 2025	2024	2023
Renewables SBU	$ 94	$ 110	$ 183	$ 499	$ 394	$ 310	$ (14)	$ 19	$ 41
Utilities SBU	9	12	12	300	294	243	8	4	5
Energy Infrastructure SBU	160	232	335	305	503	550	9	10	6
New Energy Technologies SBU	7	7	2	—	—	—	(41)	(20)	(84)
Corporate and Other	17	20	19	303	294	216	(17)	(39)	—
Total	$ 287	$ 381	$ 551	$ 1,407	$ 1,485	$ 1,319	$ (55)	$ (26)	$ (32)

The following table presents information, by country, about the Company's consolidated operations for each of the years ended December 31, 2025, 2024, and 2023, and as of December 31, 2025 and 2024 (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.

	Total Revenue			Long-Lived Assets	
Year Ended December 31,	**2025**	**2024**	**2023**	**2025**	**2024**
United States [1]	$ 5,056	$ 4,689	$ 4,439	$ 29,227	$ 25,261
Non-U.S.:					
Chile	1,516	1,534	1,932	4,411	3,563
Dominican Republic	1,363	1,451	1,400	784	805
El Salvador	1,086	1,036	935	511	472
Mexico	760	462	536	267	275
Bulgaria	687	478	528	186	421
Panama	649	666	644	1,829	1,882
Colombia	422	686	706	435	358
Argentina	366	318	407	475	437
Vietnam [2]	321	312	344	—	—
Jordan	6	28	97	36	38
Brazil	—	616	697	—	—
Other Non-U.S.	1	2	3	26	26
Total Non-U.S.	7,177	7,589	8,229	8,960	8,277
Total	$ 12,233	$ 12,278	$ 12,668	$ 38,187	$ 33,538

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(1) Includes Puerto Rico revenues of $404 million, $426 million, and $269 million for the years ended December 31, 2025, 2024, and 2023, respectively, and long-lived assets of $983 million and $572 million as of December 31, 2025 and 2024, respectively.

(2) The Mong Duong 2 power project is operated under a BOT contract. Future expected payments for the construction performance obligation are recognized in *Loan receivable* on the Consolidated Balance Sheets as of December 31, 2025. The Mong Duong assets were classified as held-for-sale as of December 31, 2024. See Note 21—*Revenue* and Note 25—*Held-for-Sale and Dispositions* for further information.

20. 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, 2025, 2024, and 2023, 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, 2025, 2024, and 2023 had grant date weighted average fair values per RSU of $10.59, $16.01, and $22.33, respectively.

The 2023 RSUs awarded to certain executives have a performance condition related to the achievement of environmental and social goals for the three-year period ending December 31, 2025. 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,	**2025**	**2024**	**2023**
RSU expense before income tax	$ 20	$ 22	$ 16
Tax benefit	(3)	(5)	(3)
RSU expense, net of tax	$ 17	$ 17	$ 13
Total value of RSUs converted [1]	$ 8	$ 9	$ 10
Total fair value of RSUs vested	$ 23	$ 19	$ 15

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(1) Amount represents fair market value on the date of conversion.

Cash was not used to settle RSUs in the years ended December 31, 2025, 2024, and 2023. Compensation costs of $3 million, $2 million, and $1 million were capitalized as part of the cost of an asset in the years ended December 31, 2025, 2024, and 2023, respectively. As of December 31, 2025, total unrecognized compensation cost related to RSUs of $20 million is expected to be recognized over a weighted average period of approximately 1.6 years. There were no modifications to RSU awards during the year ended December 31, 2025.

A summary of the activity of RSUs for the year ended December 31, 2025 follows (RSUs in thousands):

	RSUs	Weighted Average Grant Date Fair Values	Weighted Average Remaining Vesting Term (in years)
Nonvested at December 31, 2024	2,611	$ 18.64	
Vested	(1,157)	19.71	
Forfeited and expired	(388)	16.45	
Granted	1,645	10.59	
Nonvested at December 31, 2025	2,711	$ 13.60	1.6
Expected to vest at December 31, 2025	36,666	$ 13.68	

The Company initially recognizes compensation cost on the estimated number of instruments for which the requisite service is expected to be rendered. In 2025, AES has estimated a weighted average forfeiture rate of 4.08% for RSUs granted in 2025. 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 $17 million on a straight-line basis over a weighted average period of 3 years.

The following table summarizes the RSUs that vested and were converted during the periods indicated (RSUs in thousands):

Year Ended December 31,	2025	2024	2023
RSUs vested during the year	1,157	811	632
RSUs converted during the year, net of shares withheld for taxes	737	514	407
Shares withheld for taxes	420	297	225

OTHER SHARE BASED COMPENSATION

The Company has three other share-based award programs. The Company has recorded expense of $14 million, $12 million, and $2 million for 2025, 2024, and 2023, respectively, related to these programs.

Performance Stock Units — In 2023, 2024, and 2025, the Company issued PSUs to officers under its long-term compensation plan. PSUs are stock units which include performance conditions 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 2023, 2024, and 2025, the Company issued PCUs to its officers under its long-term compensation plan. The value for the 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. The value for the 2024 and 2025 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 a Clean Energy peer group 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.

21. REVENUE

The following table presents our revenue from contracts with customers and other revenue for the periods indicated (in millions):

	Year Ended December 31, 2025					
	Renewables SBU	Utilities SBU	Energy Infrastructure SBU	New Energy Technologies SBU	Corporate, Other, and Eliminations	Total
Non-Regulated Revenue						
Revenue from contracts with customers	$ 2,757	$ 80	$ 4,961	$ —	$ (205)	$ 7,593
Other non-regulated revenue [(1)]	156	4	441	1	—	602
Total non-regulated revenue	2,913	84	5,402	1	(205)	8,195
Regulated Revenue						
Revenue from contracts with customers	—	4,007	—	—	—	4,007
Other regulated revenue	—	31	—	—	—	31
Total regulated revenue	—	4,038	—	—	—	4,038
Total revenue	$ 2,913	$ 4,122	$ 5,402	$ 1	$ (205)	$ 12,233

	Year Ended December 31, 2024					
	Renewables SBU	Utilities SBU	Energy Infrastructure SBU	New Energy Technologies SBU	Corporate, Other, and Eliminations	Total
Non-Regulated Revenue						
Revenue from contracts with customers	$ 2,401	$ 82	$ 5,512	$ 1	$ (154)	$ 7,842
Other non-regulated revenue [(1)]	216	4	695	—	(1)	914
Total non-regulated revenue	2,617	86	6,207	1	(155)	8,756
Regulated Revenue						
Revenue from contracts with customers	—	3,496	—	—	—	3,496
Other regulated revenue	—	26	—	—	—	26
Total regulated revenue	—	3,522	—	—	—	3,522
Total revenue	$ 2,617	$ 3,608	$ 6,207	$ 1	$ (155)	$ 12,278

	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	$ 2,275	$ 68	$ 6,150	$ 75	$ (123)	$ 8,445
Other non-regulated revenue [(1)]	141	4	655	1	(1)	800
Total non-regulated revenue	2,416	72	6,805	76	(124)	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	$ 2,416	$ 3,495	$ 6,805	$ 76	$ (124)	$ 12,668

(1) Other non-regulated revenue primarily includes lease and derivative activity 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 $374 million and $237 million as of December 31, 2025 and December 31, 2024, respectively.

During the years ended December 31, 2025 and 2024, we recognized revenue of $52 million and $79 million, respectively, that was included in the corresponding contract liability balance at the beginning of the periods.

In July 2025, the Company entered into a development framework agreement ("DFA") with a customer to develop a private-use network structure to support the customer's planned data center in Texas. At December 31, 2025, the estimation of the transaction price was approximately $481 million using the expected value method, which incorporated management's best estimate of the consideration to be received without significant risk of revenue reversal. As the Company's performance does not create an asset with an alternative use and the Company has an enforceable right to payment for performance completed to date, revenue associated with the performance obligation is recognized over time on a time-elapsed method, which results in revenue being recognized on a straight-line basis throughout the performance period of approximately two years. During the year ended December 31, 2025, the Company recognized $105 million in revenue. The contract liability balance as of December 31, 2025 related to this contract was $245 million.

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 provided capacity through May 2024. The termination represented a contract modification under which the discounted termination payments, as well as a pre-existing contract liability, were recognized as revenue on a straight-line basis over the remaining performance obligation period for approximately $32 million per month. On February 1, 2024, the Company executed a receivable sale agreement to transfer all of its rights, title, and interest in the remaining future cash flows under this agreement. At the time of execution, the transaction was considered a sale of future revenue under U.S. GAAP, and as such, the net proceeds of $273 million were recorded as debt. Upon completion of the remaining performance obligation in May 2024, the corresponding receivable balance of $267 million, net of valuation allowance of $7 million, and the remaining debt balance of $260 million were derecognized upon accounting for the transaction as a sale of receivables.

A significant financing arrangement exists for our Mong Duong plant in Vietnam. The plant was constructed under a BOT contract and sold to the Vietnamese government, while we remain the operator for the duration of the 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, 2024, Mong Duong met the held-for-sale criteria and the loan receivable balance of $963 million was classified in held-for-sale assets. At December 31, 2025, Mong Duong no longer met the held-for-sale criteria. Of the loan receivable balance of $862 million, $107 million was classified in *Other current assets* and $755 million was classified in *Loan receivable* on the Consolidated Balance Sheets. See Note 25—*Held-for-Sale and Dispositions* for further information.

Remaining Performance Obligations — The transaction price allocated to remaining performance obligations represents future revenue for unsatisfied (or partially unsatisfied) performance obligations at the end of the reporting period. As of December 31, 2025, the aggregate amount of transaction price allocated to remaining performance obligations was $396 million, primarily consisting of fixed consideration in development services contracts in the U.S., of which $247 million has been collected. We expect to recognize revenue of approximately $264 million in 2026, $127 million in 2027, and the remainder thereafter.

22. 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, gains on contingent consideration remeasurement, and other income from miscellaneous transactions. Other expense generally includes losses on asset sales and dispositions, losses on legal contingencies, losses on remeasurement of contingent consideration, losses at commencement of sales-type leases, and losses from other miscellaneous transactions. The components are summarized as follows (in millions):

	Year Ended December 31,	2025	2024	2023
Other Income	Gain on remeasurement of contingent consideration [1]	$ 28	$ 33	$ 16
	Gain on write-off of contingent liabilities [2]	10	—	—
	Dividend income on investments	5	4	6
	AFUDC (US Utilities)	3	10	14
	Insurance proceeds	2	12	6
	Gain on sale and disposal of assets	1	4	19
	Gain on bargain purchase [3]	—	20	—
	Gain on acquisition [4]	—	14	—
	Indexation adjustment of receivables [5]	—	12	—
	Contract termination	—	5	—
	Gain on commencement of sales-type leases	—	5	—
	Legal settlements	—	—	4
	Other	18	37	24
	Total other income	$ 67	$ 156	$ 89
Other Expense	Loss on commencement of sales-type leases [6]	$ 231	$ 72	$ 20
	Loss on remeasurement of contingent consideration [1]	117	43	—
	Loss on remeasurement of investment [7]	48	—	—
	Loss on sale and disposal of assets [8]	15	13	49
	Non-service pension and other postretirement costs	6	10	12
	Legal contingencies and settlements	6	—	2
	Cost related to troubled debt restructuring [9]	—	20	—
	Other	35	17	16
	Total other expense	$ 458	$ 175	$ 99

(1) Related to certain remeasurements of contingent consideration, primarily on projects acquired at AES Clean Energy. See Note 26—*Acquisitions* for further information about development projects recently acquired and Note 5—*Fair Value* for further information about remeasurement to fair value.

(2) Related to the write-off of contingent consideration for a renewables development project at AES Andes. See Note 23—*Asset Impairment Expense* for further information.

(3) For the year ended December 31, 2024, related to a bargain purchase gain recognized on the Madison and Birdseye acquisition. See Note 26—*Acquisitions* for further information.

(4) For the year ended December 31, 2024, related to the acquisition of Felix, a VIE that does not meet the definition of a business. See Note 26—*Acquisitions* for further information.

(5) For the year ended December 31, 2024, related to an indexation adjustment on receivables for regulated energy contracts impacted by the Tariff Stabilization Laws at Chile. See Note 7—*Financing Receivables* for further information.

(6) Related to losses recognized at commencement of sales-type leases at AES Clean Energy and AES Renewable Holdings. See Note 15—*Leases* for further information.

(7) Related to the remeasurement of our existing investment in 5B, accounted for using the measurement alternative. See Note 5—*Fair Value* for further information.

(8) 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.

(9) For the year ended December 31, 2024, related to legal expenses and other direct costs associated with the troubled debt restructuring at Puerto Rico. See Note 12—*Obligations* for further information.

23. ASSET IMPAIRMENT EXPENSE

The following table presents our asset impairment expense (reversals) for the periods indicated (in millions):

Year ended December 31, (in millions)	2025	2024	2023
Maritza	$ 264	$ —	$ —
AES Clean Energy Development Projects	157	95	151
AES Andes Development Project	16	—	—
Mong Duong	(226)	62	167
Ventanas	—	125	—
AES Brasil	—	80	—
Warrior Run	—	—	198
New York Wind	—	—	186
Norgener	—	—	137
TEG	—	—	77
TEP	—	—	59
Jordan	—	—	59
GAF Projects (AES Renewable Holdings)	—	—	18
Other	13	12	15
Total	$ 224	$ 374	$ 1,067

Maritza — The Maritza coal-fired plant is operating under a PPA that expires in May 2026. Although negotiations are underway for a new PPA and other alternatives to realize additional value are being considered, no agreements have been reached. Further, in the fourth quarter of 2025, the Company made the decision not to invest in the conversion of the plant to an alternative fuel source. The Company determined that collectively, these events represent an impairment indicator. The Company reassessed the useful life of the facility and performed an impairment analysis as of October 31, 2025, in which it was determined that the carrying value of the asset group was not recoverable. The Maritza asset group was determined to have a fair value of $141 million using the income approach. As a result, the Company recognized pre-tax asset impairment expense of $264 million. Maritza is reported in the Energy Infrastructure SBU reportable segment.

AES Clean Energy Development Projects — AES Clean Energy Development has a pipeline of U.S. renewables 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 determined to be zero as there are no future projected cash flows.

In 2025, 2024, and 2023, the Company recognized pre-tax asset impairment expense related to the write-off of projects that were determined to be no longer viable totaling $157 million, $95 million, and $151 million, respectively. Of the pre-tax asset impairment expense recorded during 2025, $51 million was related to right sizing our development company as part of the restructuring program initiated in February 2025. See Note 30—*Restructuring* for further information. The impairment expense recognized in 2023 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 in 2021. AES Clean Energy Development is reported in the Renewables SBU reportable segment.

AES Andes Development Project — In September 2025, the Company determined that a renewables development project at AES Andes was no longer viable. The Company recognized pre-tax impairment expense of $16 million related to the write-off of intangible assets and capitalized development costs as the fair value of the project was determined to be zero. In addition, the Company recognized a $10 million gain in *Other income* due to the write-off of contingent consideration associated with the original acquisition of the project. See Note 22—*Other Income and Expense* for further information. AES Andes 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"). The carrying amount of the Mong Duong disposal group, which primarily consisted of our loan receivable from the sale of the power plant to the Vietnamese government, in subsequent periods exceeded the expected sales proceeds and as a result, the

Company recognized pre-tax impairment expense of $62 million and $167 million during the years ended December 31, 2024, and 2023, respectively, and $17 million during the three months ended March 31, 2025,

As of May 31, 2025, due to delays in closing the transaction and the pending expiration of the agreement in November 2025, the Company determined Mong Duong no longer met the held-for-sale criteria. As such, the Mong Duong asset group was reclassified as held and used. The loan receivable was remeasured at amortized cost and non-loan assets were each individually remeasured at the lower of (i) carrying value before being classified as held for sale, adjusted for any depreciation expense or impairment losses that would have been recognized had the assets been continuously classified as held and used, or (ii) fair value at the date of the subsequent determination that held-for-sale criteria was no longer met. As a result, the Company recorded a $243 million increase in the carrying value of the Mong Duong asset group due to the derecognition of a $239 million valuation allowance on the loan receivable accounted for under ASC 310, which had been recognized in *Asset impairment expense* between December 31, 2023 and March 31, 2025 while Mong Duong was classified as held-for-sale, and the elimination of $4 million in net estimated costs to sell from the measurement of the asset group. See Note 25—*Held-for-Sale and Dispositions* for further information. Mong Duong is reported in the Energy Infrastructure SBU reportable segment.

Ventanas — In December 2024, the Company entered into an agreement to sell Ventanas, a coal-fired plant in Chile, and Nucleo SpA, an entity comprised of a labor force and an O&M contract with Ventanas (collectively "Ventanas"). As of December 31, 2024, Ventanas was classified as held-for-sale. The carrying amount of the Ventanas disposal group exceeded the agreed-upon sales price and as a result, the Company recognized pre-tax impairment expense of $125 million. The sale of Ventanas closed in January 2025. See Note 25—*Held-for-Sale and Dispositions* for further information. Prior to its sale, Ventanas was reported in the Energy Infrastructure SBU reportable segment.

AES Brasil — In May 2024, the Company entered into an agreement to sell its 47.3% controlling interest in AES Brasil, a 5.2 GW portfolio of renewable energy facilities. Upon meeting the held-for-sale criteria in May 2024, the Company performed an impairment analysis and determined that the carrying value of the disposal group of $1,577 million was greater than its fair value less costs to sell of $1,552 million. As a result, the Company recognized pre-tax impairment expense of $25 million. The Company performed a subsequent impairment analysis as of September 30, 2024 and recognized additional pre-tax impairment expense of $55 million, primarily due to depreciation of the Brazilian real and increased costs to sell. The sale of AES Brasil closed in October 2024. See Note 25—*Held-for-Sale and Dispositions* for further information. Prior to its sale, AES Brasil was reported in the Renewables SBU reportable segment.

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 were limited to the carrying value of the long-lived assets, the Company recognized pre-tax asset impairment expense of $198 million. The Company retired the generation facility in June 2024. Prior to its retirement, Warrior Run was reported in the Energy Infrastructure SBU reportable segment.

New York Wind — In November 2023, AES Clean Energy Development, LLC 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.

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 were limited to the carrying amount of the long-lived assets, the Company recognized pre-tax asset impairment expense of $137 million. The Company retired the generation facility in April 2024. Prior to its retirement, Norgener was reported in the Energy Infrastructure SBU reportable segment.

Jordan — In November 2020, the Company signed an agreement to sell approximately 26% ownership interest in Amman East and IPP4 for $58 million. The generation plants were classified as held-for-sale until the sale was completed in March 2024. Due to the delay in closing the transaction, the carrying amount of the disposal group in subsequent periods exceeded the agreed-upon sales price, and total pre-tax impairment expense of $59 million was recorded during 2023. See Note 25—*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.

24. INCOME TAXES

Income Tax Provision — The following table summarizes the expense/(benefit) for income taxes on continuing operations for the periods indicated (in millions):

December 31,		2025	2024	2023
Federal:	Current	$ (5)	$ 4	$ 9
	Deferred	(451)	(220)	15
State:	Current	2	29	16
	Deferred	6	23	30
Foreign:	Current	320	249	289
	Deferred	(53)	(26)	(98)
Total		$ (181)	$ 59	$ 261

Effective and Statutory Rate Reconciliation — The following table summarizes a reconciliation of the U.S. statutory federal income tax expense/(benefit) and rate to the Company's effective income tax expense/(benefit) and rate, expressed as both amounts and percentages of income from continuing operations before income taxes, for the year ended December 31, 2025, following the prospective adoption of ASU 2023-09:

December 31,	**2025**	
	Amount	Percent
Statutory Federal tax rate	$ 16	21 %
State and Local Income Taxes, Net of Federal Income Tax Effects [(1)]	6	8 %
Foreign Tax Effects		
Argentina		
Inflationary adjustments	20	27 %
Valuation allowance	(50)	(67)%
Other	23	31 %
Bulgaria	28	37 %
Chile		
Foreign Tax Credits	(35)	(47)%
Foreign Dividends	35	47 %
Other	23	31 %
Colombia		
Tax rate differential	27	36 %
Other	1	1 %
Vietnam		
Tax rate differential	(53)	(71)%
Other	(11)	(15)%
Other Foreign Jurisdictions	50	67 %
Effect of Changes in Tax Laws or Rates Enacted in the Current Period	—	— %
Effect of Cross-Border Tax Laws	7	9 %
Tax Credits		
U.S. Investment Tax Credits	(593)	(791)%
Other	(1)	(1)%
Changes in Valuation Allowances	120	160 %
Nontaxable or Nondeductible Items	3	4 %
Changes in Unrecognized Tax Benefits	6	8 %
Other Adjustments		
Tax basis reduction on Investment Tax Credit	67	89 %
U.S. capital losses	(121)	(161)%
Noncontrolling interest in U.S. subsidiaries	244	325 %
Other	7	9 %
Effective Tax Rate	$ (181)	(241)%

(1) State taxes in New York, Utah, and Ohio Municipalities made up the majority (greater than 50 percent) of the tax effect in this category.

For 2025, the $(593) million U.S. Investment Tax Credits item relates to investment tax credits for renewables projects placed in service this year, and it is partially offset by the $67 million of Tax basis reduction on Investment Tax Credit item. The $(121) million U.S. capital losses item relates to capital losses associated with the sale of an indirect equity interest in AES Ohio, which is fully offset within the $120 million valuation allowance item.

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 years prior to the adoption of ASU 2023-09:

December 31,	2024	2023
Statutory Federal tax rate	21 %	21 %
State and Local Income Taxes, Net of Federal Income Tax Effects	(2)%	87 %
Taxes on foreign earnings	(10)%	14 %
Valuation allowance	52 %	83 %
U.S. Investment Tax Credit	(31)%	(70)%
Noncontrolling interest in U.S. subsidiaries	25 %	115 %
Nondeductible goodwill impairments	— %	3 %
U.S. capital loss	(41)%	— %
U.S. interest expense	(5)%	— %
Other—net	(2)%	(2)%
Effective tax rate	7 %	251 %

For 2024, the (31)% U.S. Investment Tax Credit relates to investment tax credits for renewables projects placed in service in the prior year. The (41)% U.S. capital loss relates to capital losses associated with the restructuring of a foreign holding company, which is offset in part by valuation allowance of approximately $304 million. The associated state impact is included in the (2)% state taxes, net of Federal tax benefit and is offset by valuation allowance of $74 million. Further, included in the (10)% taxes on foreign earnings is approximately $42 million of income tax benefit for the tax over book investment basis difference related to Ventanas.

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 in 2023. 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 18—*Equity* for details of the sales.

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,	2025	2024
Income taxes receivable—current	$ 69	$ 85
Income taxes receivable—noncurrent	19	32
Total income taxes receivable	$ 88	$ 117
Income taxes payable—current	$ 117	$ 71
Income taxes payable—noncurrent	—	—
Total income taxes payable	$ 117	$ 71

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, 2025, the Company had federal net operating loss carryforwards for tax return purposes of approximately $1.3 billion, which carry forward indefinitely. The Company also had capital loss carryforwards of approximately $2.1 billion, which expire in 2029 and 2030. Further, the Company had federal general business tax credit carryforwards of approximately $76 million, which expire primarily in 2040 and beyond. The Company had state net operating loss carryforwards as of December 31, 2025 of approximately $4.9 billion expiring primarily in years 2026 to 2045. As of December 31, 2025, the Company had foreign net operating loss carryforwards of approximately $3 billion that expire at various times beginning in 2026 and some of which carry forward without expiration.

Valuation allowances increased $141 million during 2025 to $1,054 million at December 31, 2025. This net increase was primarily due to valuation allowance resulting from current period U.S. capital losses associated with the sale of an indirect equity interest in AES Ohio.

Valuation allowances increased $241 million during 2024 to $913 million at December 31, 2024. This net increase was primarily due to valuation allowance resulting from prior year U.S. capital losses associated with the restructuring of a foreign holding company, partially offset by valuation allowance change related to the sale of AES Brasil.

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,	2025	2024
Differences between book and tax basis of property	$ (1,193)	$ (1,104)
Investment in U.S. tax partnerships	(1,020)	(785)
Other taxable temporary differences	(383)	(438)
Total deferred tax liability	(2,596)	(2,327)
Operating loss carryforwards	1,219	933
Capital loss carryforwards	609	501
Bad debt and other book provisions	81	91
Tax credit carryforwards	71	48
Other deductible temporary differences	486	542
Total gross deferred tax asset	2,466	2,115
Less: Valuation allowance	(1,054)	(913)
Total net deferred tax asset	1,412	1,202
Net deferred tax liability	$ (1,184)	$ (1,125)

The Company considers undistributed earnings of certain foreign subsidiaries to be indefinitely reinvested outside of 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 Tax Cuts and Jobs Act ("TCJA"), future distributions from foreign subsidiaries will generally be subject to a federal dividends received deduction in the U.S. 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 $26 million, $28 million, and $19 million for the years ended December 31, 2025, 2024, and 2023, respectively. The per share effect of these benefits after noncontrolling interests was $0.03, $0.03, and $0.02 for each of the years ended December 31, 2025, 2024, and 2023, respectively. Included in the Company's income tax benefits is the benefit related to our operations in Vietnam, which is estimated to be $17 million, $14 million, and $16 million for the years ended December 31, 2025, 2024, and 2023, 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, 2025, 2024, and 2023.

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,	2025	2024	2023
U.S.	$ (893)	$ (264)	$ (238)
Non-U.S.	968	1,158	342
Total	$ 75	$ 894	$ 104

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,	2025	2024
Interest related	$ 2	$ 2
Penalties related	1	—

The following table shows the expense/(benefit) related to interest and penalties on unrecognized tax benefits for the periods indicated (in millions):

December 31,	2025	2024	2023
Total benefit for interest related to unrecognized tax benefits	$ —	$ —	$ —
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	2020 - 2025
Brazil	2019 - 2025
Chile	2022 - 2025
Colombia	2020 - 2025
Dominican Republic	2022 - 2025
El Salvador	2022 - 2025
Netherlands	2019 - 2025
Panama	2022 - 2025
United States (Federal)	2022 - 2025

As of December 31, 2025, 2024 and 2023, the total amount of unrecognized tax benefits was $109 million, $108 million, and $107 million, respectively. The total amount of unrecognized tax benefits that would benefit the effective tax rate as of December 31, 2025, 2024, and 2023 is $109 million, $108 million, and $107 million, respectively, of which $0 million, $1 million, and $1 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 2025 would be reduced by approximately $34 million of tax expense related to remeasurement from 35% to 21%.

The following is a reconciliation of the beginning and ending amounts of unrecognized tax benefits for the periods indicated (in millions):

	2025	2024	2023
Balance at January 1	$ 108	$ 107	$ 107
Additions for current year tax positions	8	—	1
Additions for tax positions of prior years	1	2	—
Reductions for tax positions of prior years	(3)	—	(1)
Settlements	—	—	—
Lapse of statute of limitations	(5)	(1)	—
Balance at December 31	$ 109	$ 108	$ 107

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, 2025. Our effective tax rate and net income in any given future period could therefore be materially impacted.

Cash Payments for Income Taxes — The following table summarizes the income taxes paid by jurisdiction, net of refunds, for the year ended December 31, 2025 (in millions), following the prospective adoption of ASU 2023-09:

Year Ended December 31,	2025
U.S. Federal	$ —
U.S. State and Local	
California	12
Other	(1)
Total State and Local	11
Foreign	
Panama	63
El Salvador	46
Dominican Republic	42
Chile	39
Bulgaria	17
Argentina	14
Colombia	(15)
Other	10
Total Foreign	216
Worldwide	$ 227

Cash paid for income taxes, net of refunds, during the years ended December 31, 2024 and 2023 was $345 million and $301 million, respectively.

25. HELD-FOR-SALE AND DISPOSITIONS

Held-for-Sale

JK Projects — In April 2025, the Company executed an agreement to contribute the Jemeiwaa Ka'I wind projects ("JK Projects") to two trusts. After closing the transaction, the Company will retain 51% ownership in the trusts, which will be accounted for as equity method investments. The transaction is expected to close in 2026. As a result, the JK Projects were classified as held-for-sale but did not meet the criteria to be reported as discontinued operations. Since the fair value exceeded the carrying value, no impairment was recorded. On a consolidated basis, the carrying value of the JK Projects as of December 31, 2025 was $45 million, including $20 million of intangible assets and $16 million of CWIP. The JK Projects are 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 a result, Mong Duong was classified as held-for-sale but did not meet the criteria to be reported as discontinued operations. The sale was subject to regulatory approval, and due to delays in closing the transaction and the pending expiration of the agreement, the Company determined the sale was no longer probable and that Mong Duong no longer met the held-for-sale criteria as of May 31, 2025. As a result, the Company recorded an increase in the carrying value of the Mong Duong asset group primarily due to the derecognition of a $239 million valuation allowance on the loan receivable accounted for under ASC 310, which had been recognized in *Asset impairment expense* between December 31, 2023 and March 31, 2025 while Mong Duong was classified as held-for-sale. The agreement expired in November 2025. As of December 31, 2025, the significant assets and liabilities of Mong Duong were loan receivables of $862 million and debt of $399 million. See Note 23—*Asset Impairment Expense* for further information. Mong Duong is reported in the Energy Infrastructure SBU reportable segment.

Dispositions

Dominican Republic Renewables — In June 2025, the Company completed the sale of 50% of its interest in AES DR Renewables Holdings, S.L. and its subsidiaries (collectively "Dominican Republic Renewables"), whose main objective is the operation and administration of energy generation assets from primary energy resources, for $103 million. The Company retained a 50% ownership interest in Dominican Republic Renewables after the sale and the business was deconsolidated and accounted for as an equity method investment. The transaction resulted in a pre-tax gain on sale of $70 million reported in *Gain on disposal and sale of business interests*, of which $37 million was related to remeasurement of the Company's retained interest to its fair value, which was determined using the market approach. See Note 9—*Investments in and Advances to Affiliates* for further information. Dominican Republic Renewables is reported in the Renewables SBU reportable segment.

Ventanas — In January 2025, the Company completed the sale of its 100% ownership interest in Empresa Electrica Ventanas SpA and Nucleo SpA (collectively "Ventanas"), owner of a coal-fired energy generation facility in Chile, for $5 million. An immaterial loss on sale was recognized as a result of this transaction. The sale did not meet the criteria to be reported as discontinued operations. Prior to its sale, Ventanas was reported in the Energy Infrastructure SBU reportable segment.

AES Brasil — In October 2024, the Company completed the sale of its 47.3% controlling interest in AES Brasil Energia S.A. ("AES Brasil"), a 5.2 GW portfolio of renewable energy that is 51% hydroelectric, 43% wind, and 6% solar, for $586 million, resulting in a pre-tax gain on sale of $312 million reported in *Gain on disposal and sale of business interests* on the Consolidated Statement of Operations. The sale did not meet the criteria to be reported as discontinued operations. Prior to its sale, AES Brasil was reported in the Renewables SBU reportable segment.

Jordan — In March 2024, the Company completed the sale of approximately 26% ownership interest in the Amman East and IPP4 generation plants for a sale price of $58 million. After adjusting for dividends received since the execution of the sale and purchase agreement, the Company received a net cash payment of $45 million. The transaction resulted in a pre-tax loss on sale of $10 million, reported in *Gain on disposal and sale of business interests* on the Consolidated Statement of Operations. After completion of the sale, the Company retained 10% ownership interest in each of the businesses. The fair value of the retained interest was measured using the market approach and the businesses were deconsolidated and accounted for as equity method investments. Amman East and IPP4 are 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 (loss) and the pre-tax income (loss) attributable to AES of disposed businesses for the periods indicated (in millions):

Year Ended December 31,	2025	2024	2023
Pre-tax income of disposed businesses:			
Dominican Republic Renewables	$ 12	$ (6)	$ (4)
Ventanas	—	3	13
AES Brasil	—	21	116
Jordan	—	15	57
Total pre-tax income of disposed businesses	$ 12	$ 33	$ 182
Pre-tax income attributable to AES of disposed businesses:			
Dominican Republic Renewables	$ 8	$ (4)	$ (3)
Ventanas	—	3	13
AES Brasil	—	7	49
Jordan	—	5	21
Total pre-tax income attributable to AES of disposed businesses	$ 8	$ 11	$ 80

26. ACQUISITIONS

Crossvine — On May 16, 2025, the Company completed the acquisition of 100% of the membership interests in Crossvine Solar 1, LLC, which is developing an 85 MW solar generation facility and an 85 MW battery storage project in Indiana, for total consideration of $78 million. The nature of the assets acquired is largely intangible, consisting mainly of a project development intangible valued at $64 million. The transaction was accounted for as an asset acquisition of a variable interest entity that did not meet the definition of a business. Crossvine is reported in the Utilities SBU reportable segment.

AES Clean Energy Wind and Solar Project Acquisitions — In 2025, the Company closed on the acquisitions of 1.8 GW of renewables development projects in Texas, New York, and Oklahoma (the purchase of 100% of the membership interests in Homer Solar Energy Center, LLC, Moraine Solar Energy Center, LLC, Tracy Solar Energy Center, LLC, and Grand Mayes solar energy projects; and White Oak and Lake Creek wind projects). The total fair value of the consideration of these acquisitions was $63 million, including contingent consideration of $37 million. The contingent consideration will be updated quarterly with any prospective changes in fair value recorded through earnings. The fair value of the consideration paid was attributed mainly to project development intangible assets. The transactions were accounted for as asset acquisitions of variable interest entities that did not meet the definition of a business.

In 2024, the Company closed on the acquisitions of 1.1 GW of renewables development projects in Texas, Virginia, Illinois, and California (the purchase of 100% of the equity interests in Armadillo, Red Brick, Pulaski, Staley, Stags, and Jasmine solar projects). The total consideration of these acquisitions was $97 million, including contingent consideration of $44 million. The contingent consideration will be updated quarterly with any prospective changes in fair value recorded through earnings. The fair value of the consideration paid was attributed to identifiable assets and liabilities, consisting of intangible assets for $92 million, primarily project development intangibles, right-of-use assets for $40 million, PP&E for $18 million, and lease liabilities for $40 million. The transactions were accounted for as asset acquisitions of variable interest entities that did not meet the definition of a business. AES Clean Energy is reported in the Renewables SBU reportable segment.

Atacama Solar — On December 27, 2024, the Company closed an agreement for the purchase of 100% of Atacama Solar SpA, which owns and operates photovoltaic plants with a capacity of 150 MW and is developing a 250 MW BESS as well as a 100 MW solar project. This acquisition will enhance the operational capacity, and the total consideration was $105 million. The main assets acquired were PP&E valued at $102 million and right-of-use assets for $28 million. The transaction was accounted for as an asset acquisition that did not meet the definition of a business. As Atacama Solar is not a VIE, any difference between the fair value of the assets and the consideration transferred was allocated to PP&E and intangible assets on a relative fair value basis. Atacama Solar is reported in the Renewables SBU reportable segment.

Felix — Felix DevCo, LLC ("Felix") was a joint venture with Air Products formed in 2022 to develop a green hydrogen production facility in Texas, and was previously accounted for as an equity method investment. On November 5, 2024, the Company acquired the remaining 50% ownership interest in Felix from Air Products as part of a step-acquisition for $34 million, including contingent consideration of $14 million. The main assets acquired were development intangibles valued at $74 million. As a result of the transaction, Felix was consolidated by the Company and no longer accounts for its investment under the equity method. The Company recognized a gain on the acquisition of $14 million reported in *Other income* on the Consolidated Statements of Operations. Felix is reported in the Renewables SBU reportable segment.

Long Point and Hot Air — On September 20, 2024, the Company entered into an agreement to purchase Long Point, an early development-stage project consisting of a 300 MW wind facility, a 150 MW solar facility, and a 40 MW battery storage facility, and Hot Air, an early development-stage 350 MW wind facility, both located in Arizona. The transaction was accounted for as an asset acquisition. The total consideration paid of $6 million, including transaction costs, was allocated to the identifiable assets and liabilities on a relative fair value basis, primarily consisting of intangible assets. The remaining contingent consideration of up to $47 million, which was not recorded at time of purchase, will be recognized as part of the projects' assets when the contingencies are resolved, and the consideration is paid or becomes payable. Long Point and Hot Air are reported in the Renewables SBU reportable segment.

Madison and Birdseye — On April 5, 2024, the Company closed on the acquisition of the Madison solar project, a 63 MW construction-stage solar project in Virginia under contract with a 15-year virtual power purchase agreement ("VPPA"), and a pipeline of early-stage renewable energy development projects ("Birdseye"), to enhance its renewable energy portfolio. The transaction was accounted for as a business combination with a purchase price of $20 million paid in cash; therefore, the assets acquired and liabilities assumed at the acquisition date, primarily consisting of CWIP valued at $78 million and an off-market VPPA liability of $53 million, were recorded at their fair values. The Company recorded preliminary amounts for the purchase price allocation at the time of the acquisition. During the fourth quarter of 2024, the Company finalized the purchase price allocation and made measurement-period adjustments to the fair value of the assets acquired, primarily due to the determination that the Madison solar project would qualify for an increased ITC based on studies performed subsequent to the acquisition date.

The acquisition resulted in a bargain purchase gain of $20 million, recognized in *Other income* on the Consolidated Statements of Operations. This gain represents the excess of the estimated fair value of the net assets acquired over the purchase price. The primary reason for the bargain purchase gain was the determination that the Madison solar project would qualify for an increased ITC, which had not been assigned value in the purchase price. Additionally, the safe harbor period was expiring at the end of 2024 for certain equipment associated with the Madison solar project, jeopardizing the tax credits associated with the asset. In order to capture the highest value from the project, the seller needed to complete a sale to a buyer that could complete construction in 2024. This is consistent with the seller's announcement in February 2023 that they would no longer invest in non-regulated solar generation projects and intended to divest their portfolio. Before recognizing the bargain purchase gain, the Company reassessed whether all assets and liabilities were correctly identified and valued. This included a reassessment of the reasonableness of all significant assumptions used in the calculation of the fair value of assets acquired and liabilities assumed, including the market PPA price, forecasted operating expenses, and the discount rates utilized. We conducted an analysis and made detailed inquiries to confirm there were no material unrecorded liabilities or contingencies that would decrease the valuation. We monitored the projects subsequent to the acquisition and did not identify any indicators that the fair value of the net assets acquired should be reduced or that the assets were impaired. Madison and Birdseye are reported in the Renewables SBU reportable segment.

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.

Hoosier Wind — In August 2023, the Company, through its subsidiary AES Indiana, filed for IURC issuance of a Certificate of Public Convenience and Necessity approving the acquisition of 100% of the interests in Hoosier Wind Project, LLC., which is an existing 106 MW wind facility located in Benton County, Indiana. IURC approval was received on January 24, 2024, and the transaction closed on February 29, 2024. The transaction was accounted for as an asset acquisition. Of the total consideration transferred of $93 million, including transaction costs, approximately $49 million was allocated to the identifiable assets acquired on a relative fair value basis, primarily consisting of tangible wind farm assets and typical working capital items. The remaining consideration was allocated to the termination of the pre-existing PPA between AES Indiana and the Hoosier Wind Project, estimated using a discounted cash flow valuation methodology, which was deferred as a long-term regulatory asset resulting from AES Indiana regulatory approval to recover associated costs. Hoosier Wind is reported in the Utilities 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 Renewables SBU reportable segment.

27. 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, 2025, 2024 and 2023, where income represents the numerator and weighted-average shares represent the denominator.

Year Ended December 31,	2025			2024			2023		
(in millions, except per share data)	Income	Shares	$ per Share	Income	Shares	$ per Share	Income	Shares	$ per Share
BASIC EARNINGS PER SHARE									
Income from continuing operations attributable to The AES Corporation common stockholders	$ 949	712	$ 1.33	$1,686	706	$ 2.39	$ 242	669	$ 0.36
Increase in redemption value of redeemable stock of subsidiaries	(10)	—	(0.02)	—	—	—	—	—	—
Income from continuing operations available to The AES Corporation common stockholders	$ 939	712	1.31	$1,686	706	2.39	$ 242	669	0.36
EFFECT OF DILUTIVE SECURITIES									
Stock options	—	—	—	—	—	—	—	1	—
Restricted stock units	—	2	—	—	2	—	—	2	—
Equity units	—	—	—	—	5	(0.02)	1	40	(0.02)
DILUTED EARNINGS PER SHARE	$ 939	714	$ 1.31	$1,686	713	$ 2.37	$ 243	712	$ 0.34

Adjustments to Redemption Value — For the year ended December 31, 2025, income from continuing operations available to the AES common stockholders included a $10 million adjustment related to the increase of the carrying value of redeemable stock of subsidiaries at the AGIC Companies.

The Company has elected to administer the entire non-fair value redemption adjustment consistent with the treatment of dividends in the earnings per share calculation. While the adjustment impacted net income available to AES common stockholders and earnings per share, it did not impact *Net income* in the Consolidated Statement of Operations. See Note 17—*Redeemable Stock of Subsidiaries* for further information.

Anti-Dilutive Securities — The calculation of diluted earnings per share excluded 2 million outstanding stock awards for the years ended December 31, 2025, 2024, and 2023, which would be anti-dilutive. These stock awards could potentially dilute basic earnings per share in the future.

AES Global Insurance — As described in Note 17—*Redeemable Stock of Subsidiaries*, on April 30, 2025, the Company sold noncontrolling interests in the AGIC Companies. It is required that either (i) the AGIC Companies achieve a minimum distribution target to the Class B Member ranging from $146 million to $199 million over pre-defined periods of time ranging from three to five years (the “distribution period”) or (ii) AGIC achieves an average cash basis quarterly net income threshold for the period comprising the relevant distribution period and the four quarters immediately prior to the start of such distribution period. AES can make disproportionate distributions to the Class B Member to meet the minimum distribution target for the distribution period. If, at the end of a distribution period, (1) such cash basis net income threshold is not met and (2) the minimum distribution target for such distribution period is not achieved, AES would be required to address the shortfall by issuing AES common stock (“Shortfall Stock”) to AGIC for the net difference between actual and targeted distributions. If AES is required to issue Shortfall Stock, the amount will be based upon the number of shares multiplied by the then current share price to equal the net difference between actual and targeted distributions. Distributions of cash from the sale of Shortfall Stock are subject to regulatory approval and at the discretion of AES.

As part of the quarterly diluted earnings per share calculation, AES evaluates whether (1) average cash basis quarterly net income in a given quarter exceeds the threshold or (2) aggregate distributions made to the investor for the related distribution period exceed such target distribution amount. If either condition is met, no Shortfall Stock will be included in the diluted earnings per share calculation. As of December 31, 2025, the average cash basis quarterly net income condition was met as it was 189% above the threshold and, therefore, no shares are included in the calculation of diluted EPS.

Equity Units — As described in Note 18—*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. The Series A Preferred Stock and the 2024 Purchase Contracts were 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 canceled upon conversion.

28. 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 19—*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 solar, hydro, wind, coal, and gas. Our utilities business comprises businesses that transmit, distribute, and in certain circumstances, generate power.

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, 2025, the Company had $1.4 billion of unrestricted cash and cash equivalents.

During 2025, 59% 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.

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 Chilean peso, the Colombian peso, the Dominican peso, the Euro, 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 2025, 2024 or 2023.

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.

29. RELATED PARTY TRANSACTIONS

Certain of our businesses in Panama 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. In the Dominican Republic, AES conducts revenue generating business with parties which are investors in AES equity method investees. These business relationships affect both *Revenue—Non-Regulated* and *Cost of Sales—Non-Regulated* on the Consolidated Statements of Operations. Furthermore, many of the Company's energy storage construction projects utilize Fluence as either a BESS supplier or EPC contractor. These related party transactions primarily impact *Property, plant, and equipment, net* on the Consolidated Balance Sheets. 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,	2025	2024	2023
Revenue—Non-Regulated	$ 591	$ 746	$ 1,055
Cost of Sales—Non-Regulated	150	143	576
Cost of Sales—Regulated	37	34	39
Interest income	8	12	9
Interest expense	22	26	36
Other income	19	23	28

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,	2025	2024
Receivables from related parties	$ 198	$ 166
Accounts and notes payable to related parties [1]	507	1,016
Property, plant, and equipment, net	1,254	851
Prepaid expenses	2	11

(1) Includes $399 million and $526 million of debt to Mong Duong Finance Holdings B.V., as of December 31, 2025 and 2024, respectively. Mong Duong was classified as held-for-sale in December 2024. As of December 31, 2025, the Company determined that Mong Duong no longer met the held-for-sale criteria. See Note 25—*Held-for-Sale and Dispositions* for further information.

30. RESTRUCTURING

In February 2025, the Company approved and initiated a restructuring program to streamline our organization given the significantly lower number of countries that we operate in. Additionally, we right-sized our development company to focus on executing on the backlog and pursuing larger but fewer projects to better serve our core customers. Pre-tax restructuring charges related to employee severance costs were $54 million for the year ended December 31, 2025. Of the $54 million recognized for the year ended December 31, 2025, $40 million was classified within *Cost of sales* and $14 million was classified as *General and administrative expenses* on the Consolidated Statements of Operations. For the year ended December 31, 2025, $21 million was recognized at the Energy Infrastructure SBU, $17 million at the Renewables SBU, $5 million at the Utilities SBU, $1 million at the New Energy Technologies SBU, and $10 million at Corporate and Other.

The Company made cash payments of $53 million during the year ended December 31, 2025, including $4 million of termination benefits previously accrued for in the projected pension benefit obligation. As of December 31, 2025, $5 million of pre-tax restructuring charges were reflected within *Accrued and other liabilities* on the Consolidated Balance Sheets.

During the year ended December 31, 2025, AES Clean Energy Development also recognized $51 million of pre-tax asset impairment expense as a result of the restructuring program. See Note 23—*Asset Impairment Expense* for further information. AES Clean Energy Development is reported in the Renewables SBU reportable segment.

31. DISCONTINUED OPERATIONS

Sul — In 2016, the Company completed the sale of Sul, its wholly-owned distribution company in Brazil, with its historical operating results reported as discontinued operations. In August 2025, an arbitration tribunal awarded the buyer an estimated $39 million in alleged damages plus interest, as well as potential future damages, under a dispute related to representations and warranties in the 2016 share purchase agreement, which the Company recognized as a loss from disposal of discontinued businesses. The Company paid approximately $39 million in November 2025 pursuant to a settlement fully resolving all claims of the buyer.

32. SUBSEQUENT EVENTS

Merger Agreement — On March 1, 2026, the Company entered into an Agreement and Plan of Merger (the “Merger Agreement”), by and among the Company, Horizon Parent, L.P., a Delaware limited partnership (“Parent”), and Horizon Merger Sub, Inc., a Delaware corporation and wholly owned subsidiary of Parent (“Merger Sub”). Pursuant to the Merger Agreement, Merger Sub will merge with and into the Company (the “Merger”), with the Company continuing as the surviving corporation in the Merger. Parent is controlled by investment vehicles affiliated with one or more funds, accounts or other entities managed or advised by Global Infrastructure Management, LLC and the EQT Infrastructure VI fund.

At the effective time of the Merger, each share of the Company’s common stock outstanding immediately before the effective time (other than (i) shares of Company common stock held by any holder who properly exercises and perfects appraisal rights under Delaware law in respect of such shares and (ii) any shares of Company common stock held in the treasury of the Company or owned, directly or indirectly, by Parent or Merger Sub) will be converted automatically into the right to receive $15.00 in cash, without interest, per share.

The Board of Directors of the Company has unanimously approved the Merger Agreement, including the Merger and the other transactions contemplated thereby, and the Board of Directors of the Company has resolved to recommend that the Company stockholders approve the Merger and adopt the Merger Agreement.

The Merger Agreement includes certain representations, warranties, and covenants. Among other things, the Company has agreed (subject to certain exceptions) to conduct its business in the ordinary course consistent with past practice and not to take specified actions prior to closing without Parent’s consent. The Company is also required to hold a special meeting of its stockholders to seek approval of the Merger and, subject to certain exceptions, it has agreed not to solicit or engage in discussions or negotiations regarding alternative business combination proposals and not to withdraw or modify the Board’s recommendation in favor of the Merger.

In addition, subject to the terms of the Merger Agreement, the Company, Parent, and Merger Sub are required to use reasonable best efforts to obtain all required regulatory approvals, including certain regulatory approvals from the PUCO, the New York Public Service Commission, the FERC, and the Committee on Foreign Investment in the United States, and the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, as well as the receipt of certain approvals under the applicable laws of certain foreign countries, so long as such approval does not result in a Burdensome Condition (as defined in the Merger Agreement).

Consummation of the Merger is subject to various closing conditions, including: (1) approval of the stockholders of the Company, (2) receipt of the specified regulatory approvals without the imposition of a Burdensome Condition, (3) absence of any law or order prohibiting the consummation of the Merger, (4) subject to materiality qualifiers, the accuracy of each party’s representations and warranties, (5) each party’s compliance in all material respects with its obligations and covenants under the Merger Agreement, and (6) the absence of a material adverse effect with respect to the Company and its subsidiaries. The completion of the Merger is not conditioned on receipt of financing by Parent.

The Merger Agreement contains certain termination rights for both the Company and Parent, including if the Merger is not consummated by June 1, 2027 (subject to extension for an additional two successive three-month periods if all of the conditions to closing, other than the conditions related to obtaining regulatory approvals, have been satisfied). The Merger Agreement also provides for certain termination rights for each of the Company and Parent, and provides that, upon termination of the Merger Agreement under certain specified circumstances, Parent would be required to pay a termination fee of $100 million or approximately $588 million (depending on the specific circumstances of termination) to the Company, and under other specified circumstances, the Company would be required to pay Parent a termination fee of approximately $321 million.

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, 2025, 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, 2025. 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, 2025.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2025, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which appears herein.

Material Weakness Remediation

As previously reported in our Annual Report on Form 10-K for the year ended December 31, 2024, management concluded that a material weakness in internal control over financial reporting existed. The Company did not design effective controls over the review of the disposition of AES Brasil, a complex non-routine transaction; specifically due to the use of incomplete data in the estimation of the fair value of the net assets of AES Brasil, which was used in calculation of the impairment expense after AES Brasil was classified as held-for-sale in Q2 2024. Throughout 2025, management implemented measures designed to remediate the control deficiency contributing to the material weakness, including: (i) policy updates detailing steps to perform in an impairment analysis of complex ownership structures, (ii) detailed instructions on considerations to be included in the fair value estimations, (iii) updates to held-for-sale and discontinued operations policies, and (iv) training to impacted personnel. During the quarter ended December 31, 2025, we completed our testing of the operating effectiveness of internal controls impacted by these remediation efforts and determined the material weakness has been remediated as of December 31, 2025.

Changes in Internal Control Over Financial Reporting

Other than the remediation efforts discussed above, there were no changes that occurred during the quarter ended December 31, 2025 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, 2025, 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, 2025, 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, 2025 and 2024, 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, 2025, and the related notes and financial statement schedule listed in the Index at Item 15(a) and our report dated March 2, 2026 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
March 2, 2026

ITEM 9B. OTHER INFORMATION

Trading Arrangements

None of the Company's directors or "officers," as defined in Rule 16a-1(f) of the Exchange Act, adopted, modified, or terminated a "Rule 10b5-1 trading arrangement" or a "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408 of Regulation S-K, during the Company's fiscal quarter ended December 31, 2025.

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 2026 Annual Meeting of Stockholders which the Registrant expects will be filed on or around March 25, 2026 (the "2026 Proxy Statement"):

- information regarding the directors required by this item found under the heading *Board and Committee Governance—Board of Directors—Biographies*;
- information regarding AES' Code of Conduct found under the heading *Corporate Governance at AES—Additional Governance Information*;
- information regarding AES' Financial Audit Committee found under the heading *Board and Committee Governance—Board Committees—Financial Audit Committee;* and
- information regarding AES' insider trading policies and procedures found under the heading *Compensation Discussion and Analysis ("CD&A")—Other Relevant Compensation Elements, Policies, and Information—Insider Trading Policy*. A copy of our insider trading policy is filed as Exhibit 19 to this Report.

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 2026 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 2026 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 2026 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 approved by AES Corporation Stockholders, as of December 31, 2025:

Securities Authorized for Issuance under Equity Compensation Plans (As of December 31, 2025)

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights (1)	(b) Weighted average exercise price of outstanding options, warrants and rights (2)	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (3)
Equity compensation plans approved by security holders	6,189,544	$ 12.50	21,164,946
Equity compensation plans not approved by security holders	—	—	—
Total	6,189,544	$ 12.50	21,164,946

(1) Table amounts are comprised of 119,051 shares issuable pursuant to Options, 4,459,459 shares relating to RSUs and PSUs (assuming 2023 PSUs at maximum and the 2024 and 2025 PSUs at target performance), and 1,611,034 shares relating to Director stock units.

(2) Reflects the weighted-average exercise price of Options, and does not take into account RSUs, PSUs or Director stock units, as such awards have no exercise price.

(3) This number reflects securities available for issuance under The AES Corporation 2025 Equity and Incentive Compensation Plan and does not include the shares relating to Options, RSUs, PSUs and Director stock units described in footnote 1.

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

The information regarding related party transactions required by this item will be included in the 2026 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 2026 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 September 30, 2024.
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.(l).
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)	Twenty-Ninth Supplemental Indenture, dated March 20, 2025, between The AES Corporation and Deutsche Bank Trust Company Americas, as Trustee, incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on March 20, 2025.
4.(j)	Base Indenture, dated May 21, 2024, 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 21, 2024.
4.(k)	First Supplemental Indenture, dated May 21, 2024, between The AES Corporation and Deutsche Bank Trust Company Americas, as Trustee is incorporated herein by reference to Exhibit 4.2 of the Company's Form 8-K filed on May 21, 2024.
4.(l)	Second Supplemental Indenture, dated December 6, 2024, 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 6, 2024.
4.(m)	Description of the Registrant's Securities (filed herewith).
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 on October 10, 2023, is incorporated herein by reference to Exhibit 10.5 of the Company's Form 10-K for the year ended December 31, 2023.

10.6	The AES Corporation Amended and Restated Deferred Compensation Program for Directors dated May 9, 2025 is incorporated herein by reference to Exhibit 10.2 of the Company's Form 10-Q for the period ended June 30, 2025.
10.7	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.
10.8	Form of AES Performance Stock Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.7 of the Company's Form 10-K for the year ended December 31, 2023.
10.9	Form of AES Restricted Stock Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.8 of the Company's Form 10-K for the year ended December 31, 2023.
10.10	Form of AES Performance Cash Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.9 of the Company's Form 10-K for the year ended December 31, 2023.
10.11	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.
10.12	Form of AES Performance Cash Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.11 of the Company's Form 10-K for the year ended December 31, 2023.
10.13	The AES Corporation Restoration Supplemental Retirement Plan, as Amended and Restated effective June 25, 2025 is incorporated herein by reference to Exhibit 10.4 of the Company's Form 10-Q for the period ended June 30, 2025.
10.13A	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.
10.14	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.
10.15	The AES Corporation Performance Incentive Plan, as Amended and Restated on October 10, 2023, is incorporated herein by reference to Exhibit 10.15 of the Company's Form 10-K for the year ended December 31, 2023.
10.16	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.
10.17	The AES Corporation Amended and Restated Executive Severance Plan and Summary Plan Description (filed herewith).
10.18	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).
10.19	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.
10.20	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.
10.21	Loan Agreement dated as of December 6, 2024 among The AES Corporation as Borrower, the banks named therein as Banks, and Sumitomo Mitsui Banking Corporation as Administrative Agent is incorporated herein by reference to Exhibit 10.21 of the Company's Form 10-K/A for the year ended December 31, 2024.
10.22	Form of AES Non-Executive Restricted Stock Unit Award Agreement under the AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.23 of the Company's Form 10-K for the year ended December 31, 2023.
10.23	The AES Corporation 2025 Equity and Incentive Compensation Plan (incorporated by reference to Exhibit 99.1 to the Company's Registration Statement on Form S-8 filed on May 9, 2025).
10.24	Loan Agreement dated as of June 13, 2025 among The AES Corporation as Borrower, the banks named therein as Banks, and JPMorgan Chase, N.A. as Administrative Agent, is incorporated herein by reference to Exhibit 10.3 of the Company's Form 10-Q for the period ended June 30, 2025.
10.25	Amendment No. 1 dated as of November 12, 2025, to the Loan Agreement dated as of June 13, 2025 among The AES Corporation as Borrower, the banks named therein as Banks, and JPMorgan Chase, N.A. as Administrative Agent (filed herewith).
10.26	Amendment No. 2 dated as of March 1, 2026, to the Loan Agreement dated as of June 13, 2025 among The AES Corporation as Borrower, the banks named therein as Banks, and JPMorgan Chase, N.A. as Administrative Agent (filed herewith).
10.27	Loan Agreement dated as of October 31, 2025 among The AES Corporation as Borrower, the banks named therein as Banks, and Wells Fargo Bank, National Association as Administrative Agent is incorporated herein by reference to Exhibit 10.1 of the Company's Form 10-Q for the period ended September 30, 2025.
10.28	Amendment No. 1 dated as of March 1, 2026, to the Loan Agreement dated as of October 31, 2025 among The AES Corporation as Borrower, the banks named therein as Banks, and Wells Fargo Bank, National Association as Administrative Agent (filed herewith).
10.29	Letter of Credit Agreement dated as of December 8, 2025, among The AES Corporation and Barclays Bank PLC (filed herewith).
19	The AES Corporation Insider Trading Policy
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, is incorporated herein by reference to Exhibit 97 of the Company's Form 10-K for the year ended December 31, 2023.
101	The AES Corporation Annual Report on Form 10-K for the year ended December 31, 2025, 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, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE AES CORPORATION
(Company)

Date: March 2, 2026

By: /s/ ANDRÉS GLUSKI
Name: **Andrés Gluski**
Chief Executive Officer

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

Name	Title	Date
* **Andrés Gluski**	Chief Executive Officer (Principal Executive Officer) and Director	March 2, 2026
* **Gerard M. Anderson**	Director	March 2, 2026
* **Inderpal S. Bhandari**	Director	March 2, 2026
* **Janet G. Davidson**	Director	March 2, 2026
* **Holly K. Koeppel**	Director	March 2, 2026
* **Julia M. Laulis**	Director	March 2, 2026
* **Alain Monié**	Director	March 2, 2026
* **John B. Morse**	Chairman of the Board and Lead Independent Director	March 2, 2026
* **Moisés Naím**	Director	March 2, 2026
* **Teresa M. Sebastian**	Director	March 2, 2026
* **Maura Shaughnessy**	Director	March 2, 2026
/s/ STEPHEN COUGHLIN **Stephen Coughlin**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 2, 2026
/s/ SHERRY L. KOHAN **Sherry L. Kohan**	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 2, 2026

*By: /s/ PAUL L. FREEDMAN — March 2, 2026
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, 2025 AND 2024

	December 31,	
	2025	2024
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 11	$ 265
Accounts and notes receivable from subsidiaries	266	446
Prepaid expenses and other current assets	81	95
Total current assets	358	806
Investment in and advances to subsidiaries and affiliates	11,520	9,786
Office Equipment:		
Cost	14	14
Accumulated depreciation	(14)	(13)
Construction in progress	7	—
Office equipment, net	7	1
Other Assets:		
Deferred financing costs, net of accumulated amortization of $14 and $12, respectively	3	5
Other assets	29	47
Total other assets	32	52
Total assets	$ 11,917	$ 10,645
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 9	$ 20
Accounts and notes payable to subsidiaries	208	190
Accrued and other liabilities	339	312
Debt—current portion	879	899
Total current liabilities	1,435	1,421
Long-term Liabilities:		
Debt	5,105	4,805
Accounts and notes payable to subsidiaries	754	307
Other long-term liabilities	560	468
Total long-term liabilities	6,419	5,580
Stockholders' equity:		
Common stock	9	9
Additional paid-in capital	5,904	5,913
Retained earnings	641	293
Accumulated other comprehensive loss	(698)	(766)
Treasury stock	(1,793)	(1,805)
Total stockholders' equity	4,063	3,644
Total liabilities and equity	$ 11,917	$ 10,645

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF OPERATIONS

YEARS ENDED DECEMBER 31, 2025, 2024, AND 2023

For the Years Ended December 31,	2025	2024	2023
		(in millions)	
Revenue from subsidiaries and affiliates	$ 23	$ 23	$ 31
Equity in earnings of subsidiaries and affiliates	675	1,641	598
Interest income	146	150	44
General and administrative expenses	(135)	(137)	(129)
Other income	17	41	11
Other expense	(6)	(16)	—
Loss on extinguishment of debt	1	—	—
Interest expense	(331)	(307)	(230)
Income before income taxes	390	1,395	325
Income tax benefit (expense)	520	284	(76)
Net income	$ 910	$ 1,679	$ 249

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

YEARS ENDED DECEMBER 31, 2025, 2024, AND 2023

	2025	2024	2023
		(in millions)	
NET INCOME (LOSS)	$ 910	$ 1,679	$ 249
Foreign currency translation activity:			
Foreign currency translation adjustments, net of income tax expense of $1, $0, and $0, respectively	114	(159)	136
Reclassification to earnings, net of $0 income tax for all periods	—	71	—
Total foreign currency translation adjustments	114	(88)	136
Derivative activity:			
Change in fair value of derivatives, net of income tax benefit (expense) of $2, $(93), and $(7), respectively	(35)	315	55
Reclassification to earnings, net of income tax benefit (expense) of $12, $(8), and $9, respectively	(2)	18	(52)
Total change in fair value of derivatives	(37)	333	3
Pension activity:			
Change in pension adjustments due to prior service cost, net of $0 income tax for all periods	1	—	1
Change in pension adjustments due to net actuarial gain (loss) for the period, net of income tax benefit of $0, $2, and $1, respectively	(2)	(5)	(4)
Reclassification of earnings, net of income tax expense of $0, $1, and $0, respectively	1	7	—
Total pension adjustments	—	2	(3)
Fair value option liabilities activity:			
Change in fair value option liabilities due to instrument-specific credit risk, net of $0 income tax for all periods	—	3	—
Total change in fair value option liabilities	—	3	—
OTHER COMPREHENSIVE INCOME	77	250	136
COMPREHENSIVE INCOME	$ 987	$ 1,929	$ 385

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF CASH FLOWS

YEARS ENDED DECEMBER 31, 2025, 2024, AND 2023

For the Years Ended December 31,	2025	2024	2023
		(in millions)	
Net cash provided by operating activities	$ 820	$ 731	$ 608
Investing Activities:			
Proceeds from the sale of business interests, net of expenses	—	566	474
Investment in and net advances to subsidiaries	(2,080)	(2,508)	(2,187)
Return of capital	970	786	1,185
Additions to property, plant, and equipment	(7)	(11)	(9)
Net cash used in investing activities	(1,117)	(1,167)	(537)
Financing Activities:			
Borrowings (repayments) under the revolver, net	379	—	(325)
Borrowings of notes payable and other coupon bearing securities	800	1,450	900
Repayments of notes payable and other coupon bearing securities	(898)	(200)	—
Repayments to subsidiaries, net	(151)	(76)	(177)
Issuance of preferred shares in subsidiaries	436	—	—
Proceeds from issuance of common stock	—	3	1
Common stock dividends paid	(501)	(483)	(444)
Payments for deferred financing costs	(8)	(21)	(14)
Other financing	(14)	(5)	(3)
Net cash provided by (used in) financing activities	43	668	(62)
(Decrease) increase in cash and cash equivalents	(254)	232	9
Cash and cash equivalents, beginning	265	33	24
Cash and cash equivalents, ending	$ 11	$ 265	$ 33
Supplemental Disclosures:			
Cash payments for interest, net of amounts capitalized	$ 292	$ 202	$ 178
Cash payments for income taxes, net of refunds	11	44	9

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)

			December 31,	
	Interest Rate	Maturity	2025	2024
Senior Unsecured Note	3.30%	2025	$ —	$ 900
Commercial paper outstanding borrowings		2026	79	—
Senior Unsecured Note	1.375%	2026	800	800
Drawings on revolving credit facility	SOFR + 1.80%	2027	300	—
Senior Unsecured Note	5.45%	2028	900	900
Senior Unsecured Note	3.95%	2030	700	700
Senior Unsecured Note	2.45%	2031	1,000	1,000
Senior Unsecured Note	5.80%	2032	800	—
Junior Unsecured Note	7.60%	2055	950	950
Junior Unsecured Note	6.95%	2055	500	500
Unamortized (discounts)/premiums & debt issuance (costs)			(45)	(46)
Subtotal			$ 5,984	$ 5,704
Less: Current maturities			(879)	(899)
Noncurrent maturities			$ 5,105	$ 4,805

FUTURE MATURITIES OF RECOURSE DEBT — As of December 31, 2025 scheduled maturities are presented in the following table (in millions):

December 31,	Annual Maturities
2026	$ 879
2027	300
2028	900
2029	—
2030	700
Thereafter	3,250
Unamortized (discount)/premium & debt issuance (costs), net	(45)
Total debt	$ 5,984

3. Dividends from Subsidiaries and Affiliates

Cash dividends received from consolidated subsidiaries were $1.4 billion, $1.6 billion, and $1.4 billion for the years ended December 31, 2025, 2024, and 2023, respectively. For the years ended December 31, 2024 and 2023, $574 million, and $474 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. There were no dividends derived from the sale of business interests for the year ended December 31, 2025. 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, 2025, 2024, and 2023.

4. Guarantees, Letters of Credit, and Surety Bonds

GUARANTEES — In connection with certain project financings (including tax equity transactions), acquisitions and dispositions, power purchases, EPC contracts, tax credit transfers, 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 letters of credit and other obligations discussed below, were limited as of December 31, 2025 by the terms of the agreements, to an aggregate of approximately $6.7 billion, representing 102 agreements with individual exposures ranging up to $1.1 billion. 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 AND SURETY BONDS — At December 31, 2025, the Parent Company had $220 million in letters of credit outstanding under bilateral agreements, representing 8 agreements with individual exposures ranging up to $92 million; $117 million in letters of credit outstanding under the unsecured credit facilities, representing 7 agreements with individual exposures ranging up to $60 million; and $50 million in letters of credit outstanding under the revolving credit facilities, representing 17 agreements with individual exposures up to $38 million. In addition, at December 31, 2025, the Parent Company had a $36 million surety bond outstanding.

The AES Corporation
4300 Wilson Boulevard
Arlington, VA 22203
USA
703-522-1315
www.aes.com