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, 2017
-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	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	**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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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. (Check one):

Large accelerated filer ☒	Accelerated filer ☐	Smaller reporting company ☐	Emerging growth company ☐
Non-accelerated filer ☐	(Do not check if a smaller reporting company)		

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates on June 30, 2017, the last business day of the Registrant's most recently completed second fiscal quarter (based on the adjusted closing sale price of $10.75 of the Registrant's Common Stock, as reported by the New York Stock Exchange on such date) was approximately $7.10 billion.

The number of shares outstanding of Registrant's Common Stock, par value $0.01 per share, on February 21, 2018 was 660,449,495.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Registrant's Proxy Statement for its 2018 annual meeting of stockholders are incorporated by reference in Parts II and III

THE AES CORPORATION FISCAL YEAR 2017 FORM 10-K
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GLOSSARY OF TERMS

The following terms and abbreviations appear in the text of this report and have the definitions indicated below:

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
AOCL	Accumulated Other Comprehensive Loss
ASC	Accounting Standards Codification
ASEP	National Authority of Public Services
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BOT	Build, Operate and Transfer
BTA	Best Technology Available
CAA	United States Clean Air Act
CAMMESA	Wholesale Electric Market Administrator in Argentina
CCGT	Combined Cycle Gas Turbine
CDPQ	La Caisse de dépôt et placement du Quebéc
CEO	Chief Executive Officer
CHP	Combined Heat and Power
COFINS	Contribuição para o Financiamento da Seguridade Social
CO_2	Carbon Dioxide
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CP	Capacity Performance
CPI	United States Consumer Price Index
CPP	Clean Power Plan
CRES	Competitive Retail Electric Service
CSAPR	Cross-State Air Pollution Rule
CWA	U.S. Clean Water Act
DG Comp	Directorate-General for Competition of the European Commission
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DP&L	The Dayton Power & Light Company
DPL	DPL Inc.
DPLER	DPL Energy Resources, Inc.
DPP	Dominican Power Partners
EBITDA	Earnings before Interest, Taxes, Depreciation & Amortization
EPA	United States Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
ERC	Energy Regulatory Commission
ERCOT	Electric Reliability Council of Texas
ESP	Electric Security Plan
EU ETS	European Union Greenhouse Gas Emission Trading Scheme
EURIBOR	Euro Inter Bank Offered Rate
EUSGU	Electric Utility Steam Generating Unit
EVN	Electricity of Vietnam
EVP	Executive Vice President
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FONINVEMEM	Fund for the Investment Needed to Increase the Supply of Electricity in the Wholesale Market
FPA	Federal Power Act
FX	Foreign Exchange
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
GRIDCO	Grid Corporation of Odisha Ltd.
GWh	Gigawatt Hours
HLBV	Hypothetical Liquidation Book Value
IBEX	Independent Bulgarian Power Exchange
IDEM	Indiana Department of Environmental Management
IPALCO	IPALCO Enterprises, Inc.
IPL	Indiana, Indianapolis Power & Light Company
IPP	Independent Power Producers
ISO	Independent System Operator
IURC	Indiana Utility Regulatory Commission

LIBOR	London Inter Bank Offered Rate
LNG	Liquefied Natural Gas
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator, Inc.
MRE	Energy Reallocation Mechanism
MW	Megawatts
MWh	Megawatt Hours
NCI	Noncontrolling Interest
NCRE	Non-Conventional Renewable Energy
NEK	Natsionalna Elektricheska Kompania (state-owned electricity public supplier in Bulgaria)
NEPCO	National Electric Power Company
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
NYSE	New York Stock Exchange
O&M	Operations and Maintenance
ONS	National System Operator
OPGC	Odisha Power Generation Corporation, Ltd.
Parent Company	The AES Corporation
Pet Coke	Petroleum Coke
PIS	Partially Integrated System
PJM	PJM Interconnection, LLC
PM	Particulate Matter
PPA	Power Purchase Agreement
PREPA	Puerto Rico Electric Power Authority
PSD	Prevention of Significant Deterioration
PSU	Performance Stock Unit
PUCO	The Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
RGGI	Regional Greenhouse Gas Initiative
RMRR	Routine Maintenance, Repair and Replacement
RSU	Restricted Stock Unit
RTO	Regional Transmission Organization
SADI	Argentine Interconnected System
SBU	Strategic Business Unit
SCE	Southern California Edison
SEC	United States Securities and Exchange Commission
SEM	Single Electricity Market
SIC	Central Interconnected Electricity System
SIN	National Interconnected System
SING	Northern Interconnected Electricity System
SIP	State Implementation Plan
SNE	National Secretary of Energy
SO_2	Sulfur Dioxide
SSO	Standard Service Offer
TECONS	Term Convertible Preferred Securities
U.S.	United States
VAT	Value Added Tax
VIE	Variable Interest Entity
Vinacomin	Vietnam National Coal-Mineral Industries Holding Corporation Ltd.
YPF	Argentina state-owned gas company

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

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, 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 inflation, demand for power, interest rates and foreign currency exchange rates, including our ability to hedge our interest rate and foreign currency risk;
- 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;
- our ability to 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 senior secured credit facility and other existing financing obligations;
- 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 manage our operational and maintenance costs, the performance and reliability of our generating plants, including our ability to reduce unscheduled down times;
- our ability to locate and acquire attractive "greenfield" or "brownfield" projects and our ability to finance, construct and begin operating our "greenfield" or "brownfield" projects on schedule and within budget;
- 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, and low levels of wind or sunlight for our wind and solar facilities;
- our ability to meet our expectations in the development, construction, operation and performance of our new facilities, whether greenfield, brownfield or investments in the expansion of existing facilities;
- the success of our initiatives in other renewable energy projects and energy storage projects;
- our ability to keep up with advances in technology;
- the potential effects of threatened or actual acts of terrorism and war;
- the expropriation or nationalization of our businesses or assets by foreign governments, with or without adequate compensation;
- our ability to achieve reasonable rate treatment in our utility businesses;

- changes in laws, rules and regulations affecting our international businesses;
- changes in laws, rules and regulations affecting our North America business, 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 tax incentives;
- changes in environmental laws, including requirements for reduced emissions of sulfur, nitrogen, carbon, mercury, hazardous air pollutants and other substances, GHG legislation, regulation, and/or treaties and coal ash regulation;
- changes in tax laws, including U.S. tax reform, and the effects of our strategies to reduce tax payments;
- the effects of litigation and government and regulatory investigations;
- our ability to maintain adequate insurance;
- decreases in the value of pension plan assets, increases in pension plan expenses, and our ability to fund defined benefit pension and other postretirement plans at our subsidiaries;
- losses on the sale or write-down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets;
- changes in accounting standards, corporate governance and securities law requirements;
- our ability to maintain effective internal controls over financial reporting;
- our ability to attract and retain talented directors, management and other personnel, including, but not limited to, financial personnel in our foreign businesses that have extensive knowledge of accounting principles generally accepted in the United States; and
- cyber-attacks and information security breaches.

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.

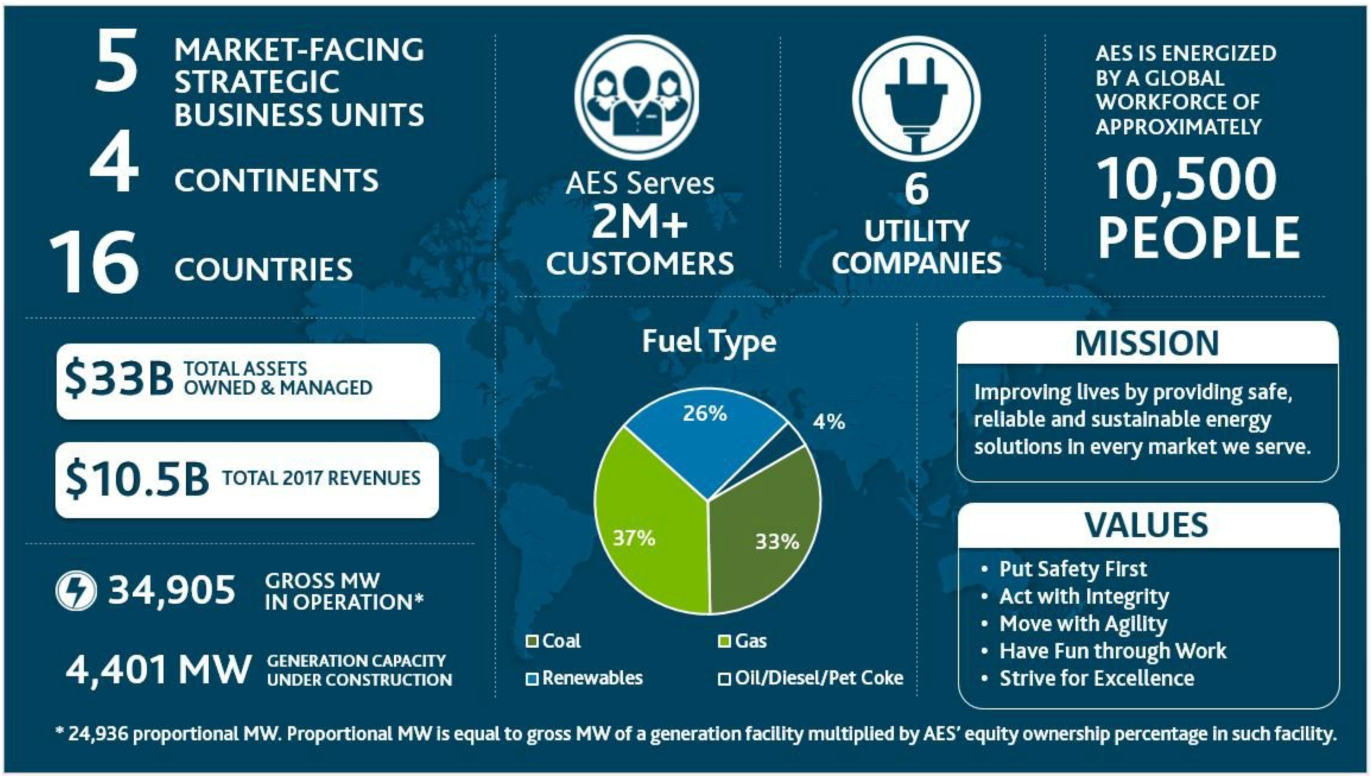
We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise. If one or more forward-looking statements are updated, no inference should be drawn that additional updates will be made with respect to those or 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 power generation and utility company, providing affordable, sustainable energy through our diverse portfolio of thermal and renewable generation facilities and distribution businesses. Our vision is to be the world's leading sustainable power company that safely provides reliable, affordable energy. We do this by leveraging our unique electricity platforms and the knowledge of our people to provide the energy and infrastructure solutions our customers need. Our people share a passion to help meet the world's current and increasing energy needs, while providing communities and countries the opportunity for economic growth due to the availability of reliable, affordable electric power.



In 2017, we announced the sale or retirement of 4.3 GW of mostly merchant coal-fired generation, representing 30% of our coal-fired capacity.

Future growth across our company will be heavily weighted toward less carbon-intensive wind, solar and gas generation. In 2017, AES and AIMCo completed the joint acquisition of sPower, the leading independent solar developer in the United States. sPower has 1.3 GW of solar and wind projects and an additional 10 GW of renewables in its development pipeline. sPower's robust development pipeline and expertise position AES to significantly grow our renewables portfolio in the coming years.

Growth in renewables not only provides an opportunity for direct investments in solar and wind generation, but also presents significant potential for energy storage. We are a leader in lithium-ion, battery-based energy storage, with approximately 400 MW in operation, under construction or in advanced development across seven countries. We believe that battery-based energy storage will play a critical role in an increasingly renewables-based generation mix. In January 2018, we partnered with Siemens to form Fluence, a new global energy storage technology and services company. Through a sales partnership with Siemens' global sales force, Fluence will be able to sell energy storage solutions and services in 160 countries as this market grows.

AES continues to invest in LNG opportunities to provide cleaner alternatives to countries with oil-fired power generation. Specifically, AES introduced LNG in the Dominican Republic in 2003 and currently has a 380 MW

CCGT and LNG storage and regasification facility under construction in Panama.

In the United States, primarily at IPL, we completed a multi-year rate base investment in environmental upgrades to our coal plants and are in the process of re-powering several units from coal to gas.

As a result of our efforts to decrease our exposure to coal-fired generation and increase our portfolio of renewables, energy storage and natural gas capacity, we are significantly reducing our carbon dioxide emissions per MWh of generation. Under our current strategy, we anticipate a reduction of carbon intensity levels by 25% from 2016 to 2020 and by 50% from 2016 to 2030.

In February 2018, we announced a reorganization as a part of our on-going strategy to simplify our portfolio, optimize our cost structure and reduce our carbon intensity. Reflecting this simplified portfolio, we will manage our global operations separate from our growth and commercial activities.

Strategic Priorities

We have made significant progress towards meeting our strategic goals to maximize value for our shareholders.

Leveraging Our Platforms

Focusing our growth in markets where we already operate and have a competitive advantage to realize attractive risk-adjusted returns

- In 2017, brought on-line seven projects for a total of 279 MW
- 4,401 MW currently under construction and expected to come on-line through 2021
- Will continue to advance select projects from our development pipeline

Reducing Complexity

Exiting businesses and markets where we do not have a competitive advantage, simplifying our portfolio and reducing risk

- Since 2011
  - Announced or closed $5.4 billion in equity proceeds from sales or sell-downs
  - Decreased total number of countries where we have operations from 28 to 16
- In 2017, announced or closed $1.1 billion in equity proceeds from sales or sell-downs of three businesses

Performance Excellence

Striving to be the low-cost manager of a portfolio of assets and deriving synergies and scale from our businesses

- Since 2012, achieved $300 million in cost savings and revenue enhancements, including $50 million in 2017
  - Includes overhead reductions, procurement efficiencies and operational improvements
  - Expect to achieve an additional $50 million in 2018 and another $50 million from 2019 to 2020, for a total of $400 million in annual savings in 2020

Expanding Access to Capital

Optimizing risk-adjusted returns in existing businesses and growth projects

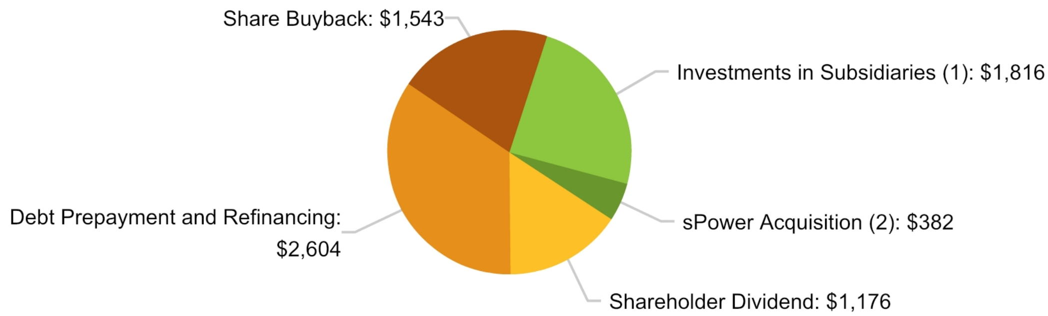
- Adjust our global exposure to commodity, fuel, country and other macroeconomic risks
- Building strategic partnerships at the project and business level with an aim to optimize our risk-adjusted returns in our business and growth projects

Allocating Capital in a Disciplined Manner

Maximizing risk-adjusted returns to our shareholders by investing our free cash flow to strengthen our credit and deliver attractive growth in cash flow and earnings

- In 2017, we generated substantial cash by executing on our strategy, which we allocated in line with our capital allocation framework
  - Used $341 million to prepay and refinance Parent Company debt
  - Returned $317 million to shareholders through quarterly dividends
    - Increased our quarterly dividend by 8.3% to $0.13 per share beginning in the first quarter of 2018
  - Invested $481 million in our subsidiaries

Allocation of $7.5 Billion in Discretionary Cash
(September 2011 - December 2017, $ in Millions)



(1) Investments in subsidiaries excludes $2.2 billion investment in DPL

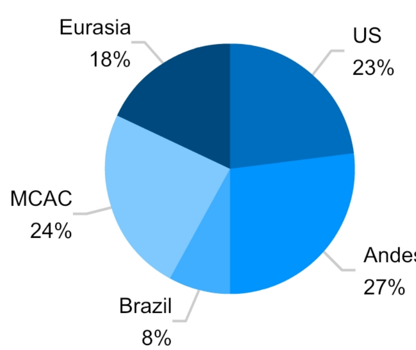
(2) Excludes working capital adjustments and growth activity prior to the close of the acquisition.

Segments

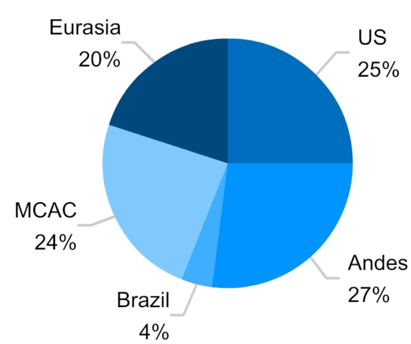
We are organized into five market-oriented SBUs: **US** (United States), **Andes** (Chile, Colombia, and Argentina), **Brazil**, **MCAC** (Mexico, Central America, and the Caribbean), and **Eurasia** (Europe and Asia) — which are led by our SBU Presidents. The Eurasia SBU resulted from the merger of the Europe and Asia SBUs in Q3 2017, in order to leverage scale. Within our five SBUs, we have two lines of business. The first business line is generation, where we own and/or operate power plants to generate and sell power to customers, such as utilities, industrial users, and other intermediaries. The second business line is utilities, where we own and/or operate utilities to generate or purchase, distribute, transmit and sell electricity to end-user customers in the residential, commercial, industrial and governmental sectors within a defined service area. In certain circumstances, our utilities also generate and sell electricity on the wholesale market.

The Company measures the operating performance of its SBUs using Adjusted PTC and Consolidated Free Cash Flow ("Free Cash Flow"), both non-GAAP measures. The Adjusted PTC and Free Cash Flow by SBU for the year ended December 31, 2017 are shown below. The percentages for Adjusted PTC and Free Cash Flow are the contribution by each SBU to the gross metric, i.e., the total Adjusted PTC by SBU, before deductions for Corporate. 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 PTC and Free Cash Flow.

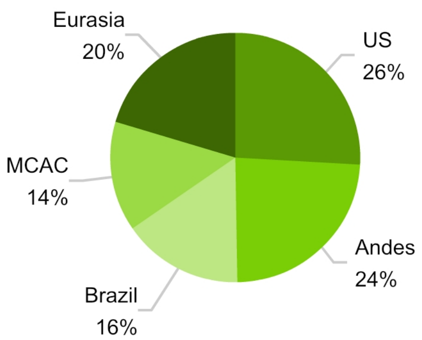
Operating Margin



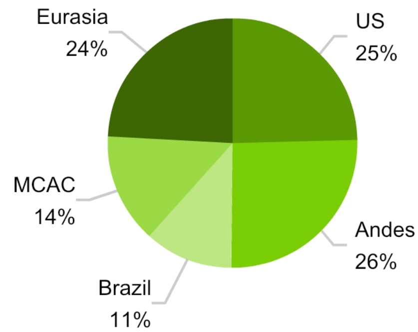
Adjusted PTC



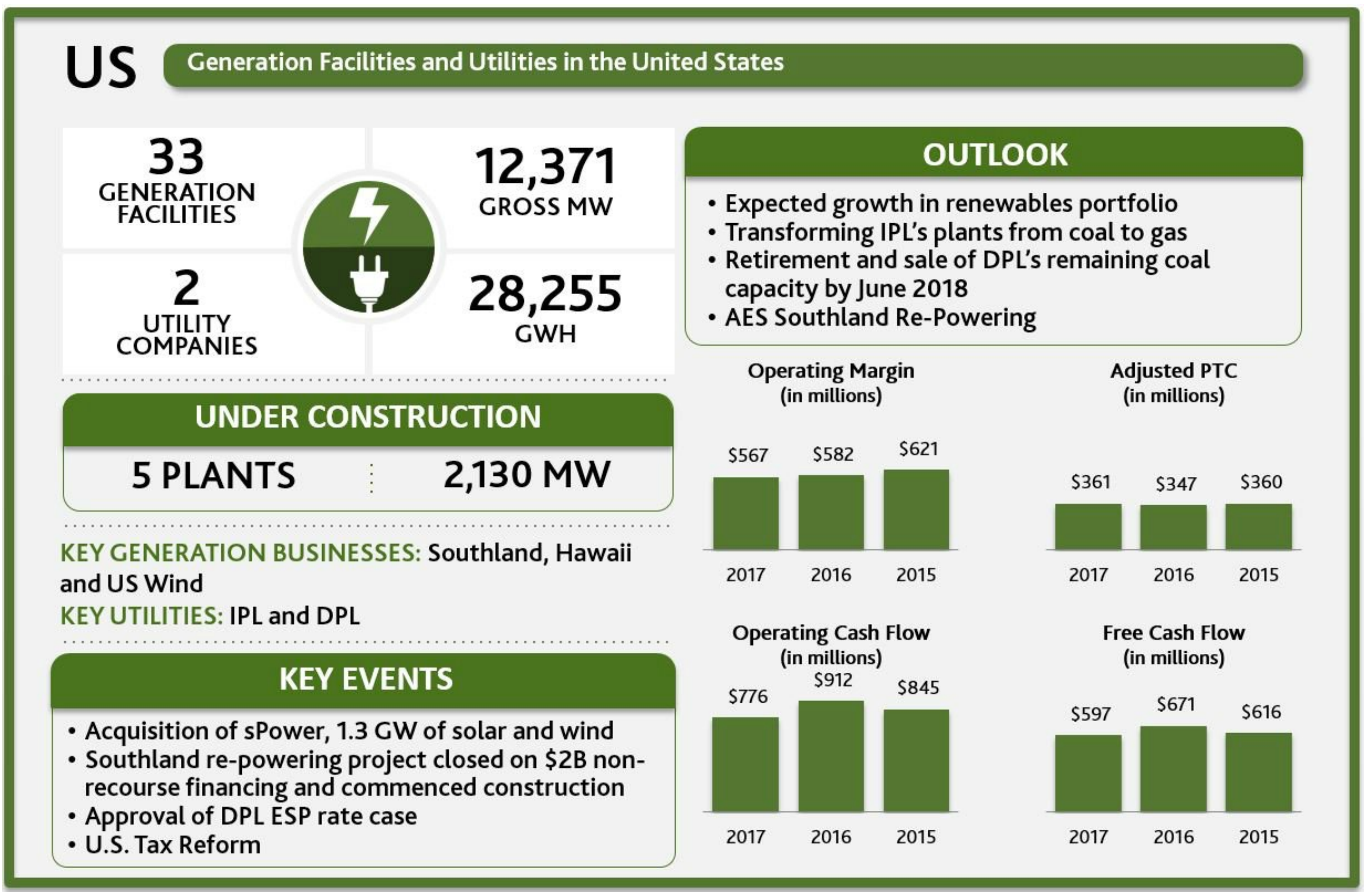
Operating Cash Flow



Free Cash Flow



The following summarizes our businesses within our five SBUs.



Andes

Generation Facilities in Chile, Colombia and Argentina

40 GENERATION FACILITIES

9,326 GROSS MW

UNDER CONSTRUCTION

1 PLANT | 531 MW

KEY GENERATION BUSINESSES: AES Gener Chile, Chivor and AES Argentina

KEY EVENTS

- Construction challenges at Alto Maipo
- Sale agreement for Electrica Santiago
- Merger of the Chilean SIC and the SING power systems
- Argentina tariff structure denominated in USD

OUTLOOK

- Possible reforms of Argentina's electricity market and privatization of FONINVEMEM
- Completion of the Electrica Santiago sale

Operating Margin (in millions)

Adjusted PTC (in millions)

Operating Cash Flow (in millions)

Free Cash Flow (in millions)

Brazil

Generation Facilities in Brazil

14 GENERATION FACILITIES

3,684 GROSS MW

KEY GENERATION BUSINESSES:
Tietê and Uruguaiana

KEY EVENTS

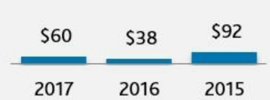
- Migration of Eletropaulo to the Novo Mercado Brazilian stock exchange
- Classification of the Eletropaulo business as a discontinued operation
- Acquisition of 386 MW Alto Sertão wind facility and 75 MW Boa Hora solar development project
- Entered agreement to acquire 150 MW Bauru solar complex

OUTLOOK

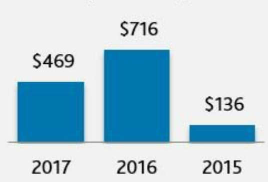
- Market reforms which may improve the economic outlook
- Expected growth in portfolio of renewables
- Considering strategic options for Eletropaulo

Operating Margin (in millions)

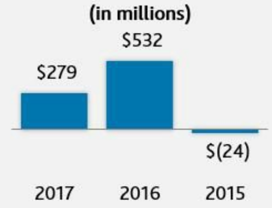
Adjusted PTC (in millions)



Operating Cash Flow (in millions)



Free Cash Flow (in millions)



MCAC

Generation Facilities and Utilities in the Dominican Republic, El Salvador, Mexico, Panama and Puerto Rico

18 GENERATION FACILITIES

4 UTILITY COMPANIES

3,381 GROSS MW

3,821 GWH

OUTLOOK

- Colón LNG terminal and gas plant in Panama to contribute to growth beyond 2018
- Growing need for natural gas in Central America
- Acquisition of 306 MW Mesa La Paz wind development project

UNDER CONSTRUCTION

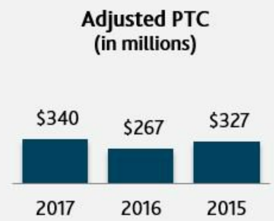
2 PLANTS | 410 MW

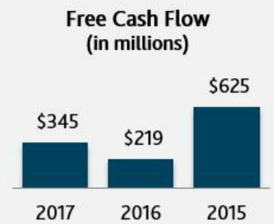
KEY GENERATION BUSINESSES: Andres, Panama and TEG TEP

KEY UTILITIES: El Salvador

KEY EVENTS

- Completed 122 MW construction project at DPP in the Dominican Republic
- Impact from Hurricanes Irma and Maria
- Changuinola tunnel assessment





Eurasia

Generation Facilities in Bulgaria, India, Jordan, Netherlands, Philippines, the United Kingdom, and Vietnam

13 GENERATION FACILITIES

6,143 GROSS MW

OUTLOOK

- OPGC expansion projects to contribute to longer-term growth
- Finalization of the Masinloc sale
- Northern Ireland market reform

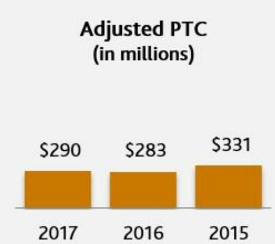
UNDER CONSTRUCTION

2 PLANTS | 1,330 MW

KEY GENERATION BUSINESSES: Maritza, Kilroot, Ballylumford, Masinloc, OPGC I and Mong Duong II

KEY EVENTS

- OPGC 2 expansion under construction
- Completion of sale of Kazakhstan coal-fired generation units
- Transfer of Kazakhstan hydroelectric plants to Republic of Kazakhstan
- Signed agreement for the sale of Masinloc



Overview

Generation

We currently own and/or operate a generation portfolio of 34,905 MW, including our integrated utility. Our generation fleet is diversified by fuel type. See discussion below under *Fuel Costs*.

Performance drivers of our generation businesses include types of electricity sales agreements, plant reliability and flexibility, fuel costs, seasonality, weather variations and economic activity, fixed-cost management, and competition.

Contract Sales — Most of our generation businesses sell electricity under medium- or long-term contracts ("contract sales") or under short-term agreements in competitive markets ("short-term sales"). Our medium-term contract sales have terms of 2 to 5 years, while our long-term contracts have terms of more than 5 years.

In contract sales, our generation businesses 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 supply agreements for a similar contract period (see discussion below under *Fuel Costs*). These contracts are intended to reduce exposure to the volatility of fuel and electricity prices by linking the business's revenues and 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.

Capacity Payments in Contract Sales — Most of our contract sales include a capacity payment that covers projected fixed costs of the plant, including fixed O&M expenses, and a return on capital invested. In addition, most of our contracts require that the majority of the capacity payment be denominated in the currency matching our fixed 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 *Capacity Payments* and *Short-Term Sales* sections below.

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

Short-Term Sales — Our other generation businesses sell power and ancillary services under short-term contracts with average terms of less than 2 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.

Capacity Payments — Many of the 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 most significant capacity revenues are earned by our generation capacity in Ohio and Northern Ireland.

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, 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 hedge our fuel costs. Some of our contracts have periodic adjustments for changes in fuel cost indices. In those cases, we have fuel supply agreements with shorter terms to match those adjustments. 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.

37% of the capacity of our generation plants are fueled by natural gas. Generally, we use gas from local suppliers in each market. A few exceptions to this are AES Gener in Chile, where we purchase imported gas from third parties, and our plants in the Dominican Republic, where we import LNG to utilize in the local market.

33% of the capacity of our generation fleet is coal-fired. In the U.S., most of our plants are supplied from domestic coal. At our non-U.S. generation plants, and at our plant in Hawaii, we source coal internationally. Across our fleet, we utilize our global sourcing program to maximize the purchasing power of our fuel procurement.

26% of the capacity of our generation plants are fueled by renewables, including hydro, solar, wind, energy storage, biomass and landfill gas, which do not have significant fuel costs.

4% of the capacity of our generation fleet utilizes pet coke, diesel or oil for fuel. Oil and diesel are sourced locally at prices linked to international markets, while pet coke is largely sourced 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. 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 competition 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

AES' six utility businesses distribute power to 2.4 million people in two countries. AES' two utilities in the U.S. also include generation capacity totaling 5,373 MW. Our utility businesses consist of IPL (an integrated utility), DPL, including DP&L (transmission and distribution) and AES Ohio Generation (generation), and four utilities in El Salvador (distribution).

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, reliability of service and competition. 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 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 with other retail energy suppliers directly 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 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 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 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 expectations.

Competition — Our integrated utility, IPL, and our regulated utility DP&L, operate as the sole distributors of electricity within their respective jurisdictions. IPL owns and operates all of the businesses and facilities necessary to generate, transmit and distribute electricity. DP&L owns and operates all of the businesses and facilities necessary to transmit and distribute electricity. Competition in the regulated electric business is primarily from the on-site generation for industrial customers. IPL is exposed to the volatility in wholesale prices to the extent our generating capacity exceeds the native load served under the regulated tariff and short-term contracts. See the full discussion under the US SBU.

At our distribution business in El Salvador, we face relatively limited competition due to significant barriers to entry. At many of these businesses, large customers, as defined by the relevant regulator, have the option to both leave and return to regulated service.

Development and Construction

We develop and construct new generation facilities. For our utility business, new plants may be built or existing plants retrofitted in response to customer needs or to comply with regulatory developments. The projects are developed subject to regulatory approval that permits recovery of our capital cost and a return on our investment. For our generation businesses, our priority for development is platform expansion opportunities, where we can add on to our existing facilities in our key platform markets where we have a competitive advantage. We make the decision to invest in new projects by evaluating the project returns and financial profile against a fair risk-adjusted return for the investment and against alternative uses of capital, including corporate debt repayment and share buybacks.

In some 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 where 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 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 business internally. It is organized by geographic regions which provide a socio-political-economic understanding of our business. 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 15—*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.

US SBU

Our US SBU has 18 generation facilities and two utilities in the United States.

Generation — Operating installed capacity of our US SBU totals 12,371 MW. IPL's parent, IPALCO Enterprises, Inc., and DPL Inc. are SEC registrants, and as such, follow public filing requirements of the Securities Exchange Act of 1934. The following table lists our US SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Southland—Alamitos	US-CA	Gas	2,075	100 %	1998	2019-2020	Southern California Edison
Southland—Redondo Beach	US-CA	Gas	1,392	100 %	1998	2018	Southern California Edison
sPower [1][2]	US-Various	Solar	1,245	50 %	2017	2028-2046	Various
Southland—Huntington Beach	US-CA	Gas	474	100 %	1998	2019-2020	Southern California Edison
Shady Point	US-OK	Coal	360	100 %	1991	2018	Oklahoma Gas & Electric
Buffalo Gap II [3]	US-TX	Wind	233	100 %	2007		
Hawaii	US-HI	Coal	206	100 %	1992	2022	Hawaiian Electric Co.
Warrior Run	US-MD	Coal	205	100 %	2000	2030	First Energy
Buffalo Gap III [3]	US-TX	Wind	170	100 %	2008		
sPower [2]	US-Various	Wind	142	50 %	2017	2036	Various
Distributed PV - Commercial & Utility [3]	US-Various	Solar	126	100 %	2015-2017	2029-2042	Utility, Municipality, Education, Non-Profit
Buffalo Gap I [3]	US-TX	Wind	119	100 %	2006	2021	Direct Energy
Laurel Mountain	US-WV	Wind	98	100 %	2011		
Mountain View I & II	US-CA	Wind	65	100 %	2008	2021	Southern California Edison
Mountain View IV	US-CA	Wind	49	100 %	2012	2032	Southern California Edison
Laurel Mountain ES	US-WV	Energy Storage	27	100 %	2011		
Warrior Run ES	US-MD	Energy Storage	10	100 %	2016		
Advancion Applications Center	US-PA	Energy Storage	2	100 %	2013		
			6,998				

(1) sPower solar MW shown in Direct Current.

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

(3) AES owns these assets together with third-party tax equity investors with variable ownership interests. The tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes, that vary over the life of the projects. The proceeds from the issuance of tax equity are recorded as noncontrolling interest in the Company's Consolidated Balance Sheets.

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

Business	Location	Fuel	Gross MW	AES Equity Interest	Expected Date of Commercial Operations
Eagle Valley CCGT	US-IN	Gas	671	70%	1H 2018
Distributed PV - Commercial	US-Various	Solar	27	100%	1H-2H 2018
Lawai	US-HI	Solar/Energy Storage	48	100%	1H 2019
Southland Re-powering	US-CA	Gas	1,284	100%	1H 2020
Alamitos Energy Center	US-CA	Energy Storage	100	100%	1H 2021
			2,130		

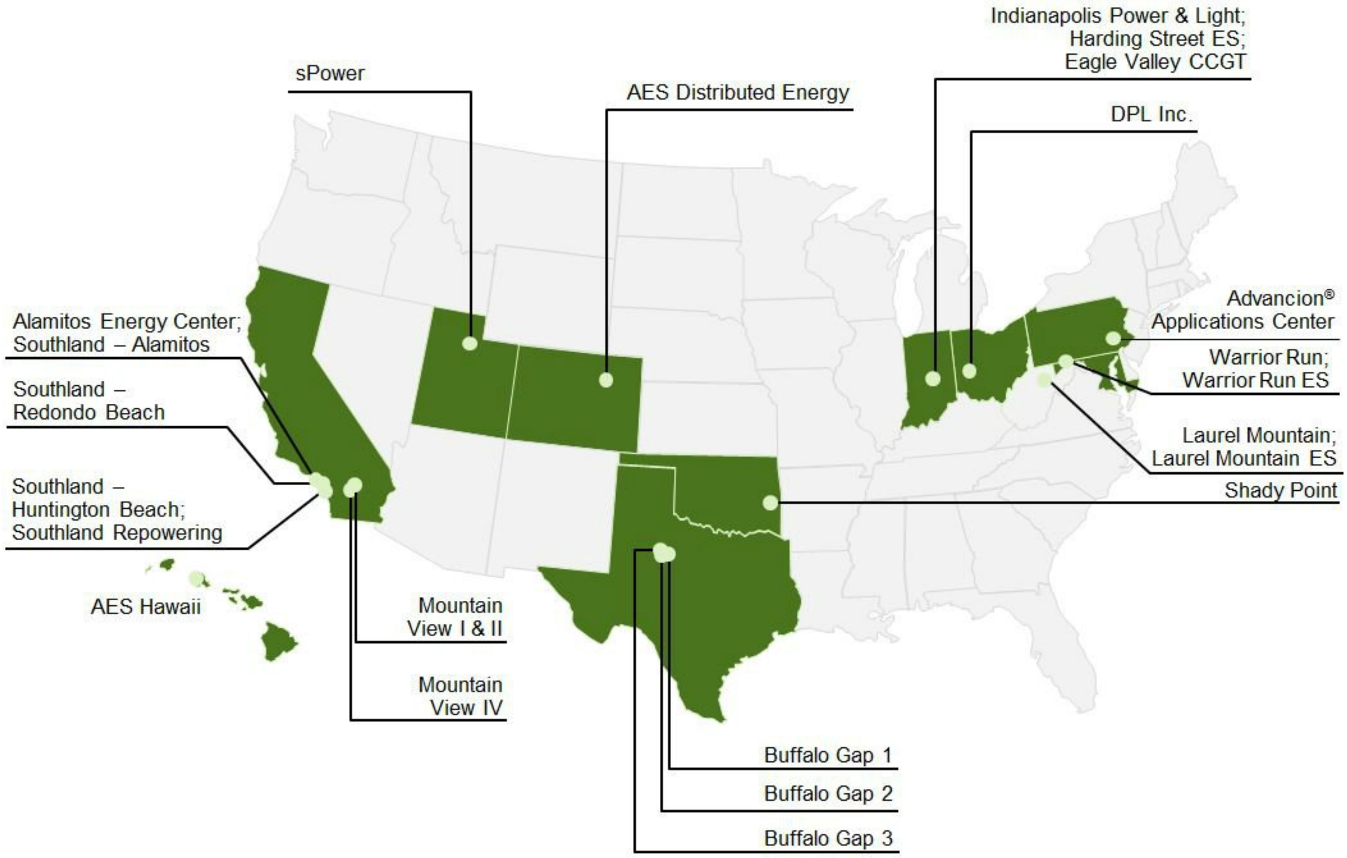
Utilities — The following table lists our U.S. utilities and their generation facilities:

Business	Location	Approximate Number of Customers Served as of 12/31/2017	GWh Sold in 2017	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation
DPL [1]	US-OH	521,000	14,771	Coal/Gas/ Diesel/Solar	2,125	100%	2011
IPL [2]	US-IN	490,000	13,484	Coal/Gas/Oil	3,248	70%	2001
		1,011,000	28,255		5,373		

(1) As of December 31, 2017, DPL's subsidiary AES Ohio Generation, LLC owned the following plants (the Peaker Assets): Tait Units 1-7 and diesels, Yankee Street, Yankee Solar, Monument, Montpelier, Hutchings and Sidney. AES Ohio Generation jointly-owned the following plants: Conesville Unit 4, Killen and Stuart. DPL subsidiary DP&L also owned a 4.9% equity ownership in OVEC, an electric generating company. OVEC has two plants in Cheshire, Ohio and Madison, Indiana with a combined generation capacity of approximately 2,109 MW. DP&L's share of this generation is approximately 103 MW. AES' share of the AES Ohio Generation jointly-owned plants, Conesville Unit 4, Stuart and Killen, represents 1,152 MW.

(2) CDPQ owns direct and indirect interests in IPALCO which total approximately 30%. AES owns 85% of AES US Investments and AES US Investments owns 82.35% of IPALCO. IPL plants: Georgetown, Harding Street, Petersburg and Eagle Valley (new CCGT currently under construction). 3.2 MW of IPL total is considered a transmission asset.

The following map illustrates the location of our U.S. facilities:



U.S. Businesses

U.S. Utilities

IPL

Regulatory Framework and Market Structure — IPL 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 power of the IURC over IPL's business is typical of regulation generally imposed by state public utility commissions. The IURC sets tariff rates for electric service provided by IPL. The IURC considers all allowable costs for ratemaking purposes, including a fair return on assets used and useful to providing service to customers.

IPL's tariff rates consist of basic rates and approved charges. In addition, IPL'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 IPL's retail load requirements, and (ii) a rider for the timely recovery of costs incurred to comply with environmental laws and regulations. These components function somewhat independently of one another, and are subject to review at the same time as any review of IPL's basic rates and charges.

IPL 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 operates on a merit order dispatch, considering transmission constraints and other reliability issues to meet the total demand in the MISO region. IPL offers electricity in the MISO day-ahead and real-time markets.

Business Description — IPL 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. IPL has an exclusive right to provide electric service to those customers. IPL's service area covers about 528 square miles with an estimated population of approximately 941,000. IPL owns and operates four generating stations all within the state of Indiana. IPL’s largest generating station, Petersburg, is coal-fired. The second largest, Harding Street, is natural gas-fired and uses natural gas and fuel oil to power combustion turbines. In addition, IPL operates a 20 MW battery-based energy storage unit at this location. The third, Eagle Valley, retired its coal-fired units in April 2016 and the new CCGT is expected to be completed in the first half of 2018 with installed capacity of 671 MW. The fourth, Georgetown, is a small peaking station that uses natural gas to power combustion turbines.

In December 2017, IPL filed an updated petition with the IURC requesting an increase to its basic rates and charges primarily to recover the cost of the new CCGT at Eagle Valley. The requested increase is proposed to coincide with the completion of the CCGT, which is expected in the first half of 2018. IPL’s proposed increase was $125 million annually, or 9%. In February 2018, IPL filed an update to the petition to reflect the newly enacted U.S. tax law, which reduced the revenue increase IPL is seeking to $97 million, or 7%. An order on this proceeding will likely be issued by the IURC by the first quarter of 2019.

Environmental Regulation — For information on compliance with environmental regulations see Item 1.—*United States Environmental and Land-Use Legislation and Regulations*.

Key Financial Drivers — IPL's financial results are driven primarily by retail demand, weather, generating unit availability, outage costs and, to a lesser extent, wholesale prices. In addition, IPL's financial results are likely to be driven by many factors, including, but not limited to:

- Rate case outcomes
- Timely completion of major construction projects and recovery of capital expenditures through base rate growth
- Passage of new legislation or implementation of or changes in regulations

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

DPL

Regulatory Framework and Market Structure — DPL is an energy holding company whose principal subsidiaries include DP&L and AES Ohio Generation, LLC, both of which operate in Ohio. Electric customers within Ohio are permitted to purchase power under contract from a 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.

DP&L 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.

While Ohio allows customers to choose retail generation providers, DP&L is required to provide retail generation service at SSO rates to any customer that has not signed a contract with a CRES provider. 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. DP&L's distribution rates are regulated by the PUCO and are established through a traditional cost-based rate-setting process. DP&L 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. DP&L's rates include various adjustment mechanisms including, but not limited to, the timely recovery of costs incurred to comply with alternative energy, renewables, energy efficiency, and economic development costs. DP&L's wholesale transmission rates are regulated by the FERC.

DP&L is a member of PJM, an RTO that operates the transmission systems owned by utilities operating in all or parts of Pennsylvania, New Jersey, Maryland, Delaware, D.C., Virginia, Ohio, West Virginia, Kentucky, North Carolina, Tennessee, Indiana and Illinois. PJM also runs the day-ahead and real-time energy markets, ancillary services market and forward capacity market for its members.

As a member of PJM, AES Ohio Generation is subject to charges and costs associated with PJM operations as approved by the FERC. The capacity construct of PJM operates under the Capacity Performance ("CP") program, which offers capacity revenues combined with penalties for non-performance or under-performance during certain periods identified as "capacity performance hours." This linkage between non- or under-performance during specific hours means that a generation unit that is generally performing well on an annual basis, may incur substantial penalties if it happens to be unavailable for service during some capacity performance hours. Similarly, a generation unit that is generally performing poorly on an annual basis may avoid such penalties if its outages happen to occur only during hours that are not capacity performance hours. An annual “stop-loss” provision exists that limits the size of penalties to 150% of the net cost of new entry, which is a value computed by PJM. This level is likely to be larger than the capacity price established under the CP program, so that there is potential that participation in the CP program could result in capacity penalties that exceed capacity revenues. The purpose of the CP program is to enable PJM to obtain sufficient resources to reliably meet the needs of electric customers within the PJM footprint. PJM conducts an auction to establish the price by zone.

Business Description — DP&L transmits, distributes and sells electricity to retail customers in a 6,000 square mile area of West Central Ohio. Ohio consumers have the right to choose the electric generation supplier from whom they purchase retail generation service; however, retail transmission and distribution services are still regulated. DP&L has the exclusive right to provide such transmission and distribution services to those customers. Additionally, DP&L procures retail SSO electric service on behalf of residential, commercial, industrial and governmental customers.

In October 2017, the PUCO approved DP&L's most recent ESP. The agreement establishes a six year settlement, an updated framework to provide retail services including rate structures, non-bypassable charges, and other specific rate recovery true-up mechanisms. The settlement also establishes a three-year non-bypassable distribution modernization rider designed to collect $105 million in revenue per year which could be extended by PUCO for an additional two years.

In October 2017, DP&L transferred its interest in its coal-fired and certain other generating units to AES Ohio Generation. AES Ohio Generation, solely or through jointly-owned facilities, owns coal-fired and peaking generation units representing 2,125 MW located in Ohio and Indiana. AES Ohio Generation sells all of its energy and capacity into the wholesale market.

In January 2017, Stuart Unit 1 failed and was retired. In March 2017 it was decided to retire the Stuart coal-fired and diesel-fired generating units and Killen coal-fired generating unit and combustion turbine on or before June 1, 2018. In December 2017, AES Ohio Generation sold its undivided interests in Zimmer and Miami Fort, and entered into an agreement to sell its 973 MW of peaking capacity.

Environmental Regulation — For information on compliance with environmental regulations see Item 1.— *United States Environmental and Land-Use Legislation and Regulations.*

Key Financial Drivers — DPL's financial results are primarily driven by retail demand, weather, energy efficiency, generating unit availability, outage costs, and wholesale prices. In addition, DPL financial results are likely to be driven by many factors, including, but not limited to:

- PJM capacity prices
- Outcome of DP&L's pending distribution rate case
- Recovery in the power market, particularly as it relates to an expansion in dark spreads
- DPL's ability to reduce its cost structure

Construction and Development — Planned construction additions primarily relate to new investments in and upgrades to DPL's power plant equipment and 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.

DPL is projecting to spend an estimated $359 million in capital projects for the period 2018 through 2020 with 94% attributable to Transmission and Distribution. DPL's ability to complete capital projects and the reliability of future service will be affected by its financial condition, the availability of internal funds and the reasonable cost of external funds. We expect to finance these construction additions with a combination of cash on hand, short-term financing, long-term debt and cash flows from operations.

U.S. Generation

Business Description — In the U.S., we own a diversified generation portfolio in terms of geography, technology and fuel source. The principal markets and locations where we are engaged in the generation and supply of electricity (energy and capacity) are the Western Electric Coordinating Council, PJM, Southwest Power Pool Electric Energy Network and Hawaii. AES Southland, in the Western Electric Coordinating Council, is our most significant generating business.

Many of our 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. The plants are generally eligible for availability bonuses on an annual basis if they meet certain requirements. In addition to plant availability, fuel cost is a key business driver for some of our facilities.

AES Southland

Business Description — In terms of aggregate installed capacity, AES Southland is one of the largest generation operators in California, with an installed gross capacity of 3,941 MW, accounting for approximately 5% of the state's installed capacity and 17% of the peak demand of SCE. The three 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.

All of AES Southland's capacity is contracted through a long-term agreement (the "Tolling Agreement"), expiring on May 31, 2018. In 2017, the California Public Utilities Commission approved the Resource Adequacy Purchase Agreements (the "RAPAs") between the SCE and AES Huntington Beach, LLC and AES Alamitos, LLC for the period of June 1, 2018 through 2020, and the SCE and AES Redondo Beach for the period of June 1, 2018 through December 31, 2018. Under the RAPAs, the generating stations will only provide resource adequacy capacity, and have no obligation to produce or sell any energy to SCE. However, the generating stations may bid energy into the California ISO markets.

Under the current Tolling Agreement, approximately 98% of AES Southland's revenue comes from availability. Historically, AES Southland has generally met or exceeded its contractual availability requirements under the Tolling Agreement and may capture bonuses for exceeding availability requirements in peak periods.

Under the Tolling Agreement, the offtaker provides gas to the three facilities thus AES Southland is not exposed to significant fuel price risk. If the units operate better than the guaranteed efficiency, AES Southland gets credit for the gas that is not consumed. Conversely, AES Southland is responsible for the cost of fuel in excess of what would have been consumed had the guaranteed efficiency been achieved. The business is also exposed to replacement power costs for a limited period if dispatched by the offtaker and not able to meet the required generation.

Environmental Regulation — For a discussion of environmental regulatory matters affecting U.S. Generation, see Item 1.—*United States Environmental and Land-Use Legislation and Regulations.*

Re-powering — In November 2014, AES Southland was awarded 20-year contracts by SCE to provide 1,284 MW of combined cycle gas-fired generation and 100 MW of interconnected battery-based energy storage. Under the contracts, all capacity will be sold to SCE in exchange for a fixed monthly capacity fee that covers fixed operating cost, debt service and return on capital. In addition, SCE will reimburse variable costs and provide the natural gas and charging electricity.

In April 2017, the California Energy Commission unanimously approved the licenses for the new combined cycle projects at AES Alamitos and AES Huntington Beach. In June 2017, AES closed the financing of $2.0 billion, funded with a combination of non-recourse debt and AES equity. The construction of this new capacity started during 2017 and commercial operation of the gas-fired capacity is expected in 2020 and the energy storage capacity in 2021.

Key Financial Drivers — AES Southland's contractual availability is the single most important driver of operations. Its units are generally required to achieve at least 86% availability in each contract year. AES Southland has historically met or exceeded its contractual availability.

Additional U.S. Generation Businesses

Regulatory Framework and Market Structure — For the non-renewable businesses, coal and natural gas are used as the primary fuels. Coal prices are set by market factors internationally, while natural gas is generally set domestically. Price variations for these fuels can change the composition of generation costs and energy prices in our generation businesses.

Many of these generation businesses have entered into long-term PPAs with utilities or other offtakers. Some businesses with PPAs have mechanisms to recover fuel costs from the offtaker, including an energy payment partially based on the market price of fuel. When market price fluctuations in fuel are borne by the offtaker, revenue may change as fuel prices fluctuate, but the variable margin or profitability should remain consistent. These businesses often have an opportunity to increase or decrease profitability from payments under their PPAs depending on such items as plant efficiency and availability, heat rate, ability to buy coal at lower costs through AES' global sourcing program and fuel flexibility.

Several of our generation businesses in the U.S. currently operate as QFs, including Hawaii, Shady Point and Warrior Run, as defined under the PURPA. These businesses entered into long-term contracts with electric utilities that had a mandatory obligation to purchase power from QFs at the utility's avoided cost (i.e., the likely costs for both energy and capital investment that would have been incurred by the purchasing utility if that utility had to provide its own generating capacity or purchase it from another source). To be a QF, a cogeneration facility must produce electricity and useful thermal energy for an industrial or commercial process or heating or cooling applications in certain proportions to the facility's total energy output and meet certain efficiency standards. To be a QF, a small power production facility must generally use a renewable resource as its energy input and meet certain size criteria.

Our non-QF generation businesses in the U.S. currently operate as Exempt Wholesale Generators as defined under EPAct 1992. 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 Federal Power 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 the 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.

Business Description — Additional businesses include thermal, wind, and solar generating facilities, of which our U.S. Renewables businesses and AES Hawaii are the most significant.

U.S. Renewables

sPower owns and/or operates more than 150 utility and distributed electrical generation systems across the U.S., actively buying, developing, constructing and operating renewable assets in the United States.

AES Distributed Energy develops, constructs and sells electricity generated by photovoltaic solar energy systems to public sector, utility, and non-profit entities through PPAs.

Excluding sPower wind plants, AES has 734 MW of wind capacity in the U.S., located in California, Texas and West Virginia. Mountain View I & II, Mountain View IV and Buffalo Gap I sell under long-term PPAs through which the energy price on the entire production of these facilities is guaranteed. Laurel Mountain, Buffalo Gap II and Buffalo Gap III are exposed to the volatility of energy prices and their revenue may change materially as energy prices fluctuate in their respective markets of operations.

AES manages the U.S. Renewables portfolio as part of its broader investments in the U.S., leveraging operational and commercial resources to supplement the experienced subject matter experts in the renewable industry to achieve optimal results. A portion of U.S. Solar projects and the majority of wind projects have been financed with tax equity structures. Under these tax equity structures, the tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes that vary over the life of the projects. Based on certain liquidation provisions of the tax equity structures, this could result in variability to earnings attributable to AES compared to the earnings reported at the facilities.

AES Hawaii

AES Hawaii receives a fuel payment from its offtaker under a PPA expiring in 2022, which is based on a fixed rate indexed to the Gross National Product — Implicit Price Deflator. Since the fuel payment is not directly linked to market prices for fuel, the risk arising from fluctuations in market prices for coal is borne by AES Hawaii.

To mitigate the risk from such fluctuations, AES Hawaii has entered into fixed-price coal purchase commitments that end in December 2018; the business could be subject to variability in coal pricing beginning in January 2019. To mitigate fuel risk beyond December 2018, AES Hawaii plans to seek additional fuel purchase commitments on favorable terms. However, if market prices rise and AES Hawaii is unable to procure coal supply on favorable terms, the financial performance of AES Hawaii could be materially and adversely affected.

Environmental Regulation — For a discussion of environmental laws and regulations affecting the U.S. business, see Item 1.—*United States Environmental and Land-Use Legislation and Regulations*.

Key Financial Drivers — U.S. thermal generation's financial results are driven by fuel costs and outages. The Company has entered into long-term fuel contracts to mitigate the risks associated with fluctuating prices. In addition, major maintenance requiring units to be off-line is performed during periods when power demand is typically lower. The financial results of U.S. Wind are primarily driven by increased production due to faster and less turbulent wind and reduced turbine outages. In addition, PJM and ERCOT power prices impact financial results for the wind projects that are operating without long-term contracts for all or some of their capacity. The financial results of U.S. Solar are primarily driven by the amount of sunshine hours available at the facilities, cell maintenance and growth in projects. Tax reform enacted December 22, 2017 will change the taxation of U.S. Generation's operations beginning in 2018. For additional details see *Key Trends and Uncertainties* in Item 7.— *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Construction and Development — Planned capital projects include the AES Southland re-powering described above. In addition to the new construction project, U.S. Generation performs capital projects related to major plant maintenance, repairs and upgrades to be compliant with new environmental laws and regulations.

Andes SBU

Generation — Our Andes SBU has generation facilities in three countries — Chile, Colombia and Argentina. AES Gener, which owns all of our assets in Chile, Chivor in Colombia and TermoAndes in Argentina, as detailed below, is a publicly listed company in Chile. AES has a 66.7% ownership interest in AES Gener and this business is consolidated in our financial statements.

Operating installed capacity of our Andes SBU totals 9,326 MW, of which 44%, 45% and 11% are located in Argentina, Chile and Colombia, respectively. The following table lists our Andes SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Chivor	Colombia	Hydro	1,000	67%	2000	Short-term	Various
Tunjita	Colombia	Hydro	20	67%	2016		
Colombia Subtotal			*1,020*				
Guacolda [1]	Chile	Coal	760	33%	2000	2018-2032	Various
Electrica Santiago [2]	Chile	Gas/Diesel	750	67%	2000		
Gener-SIC [3]	Chile	Hydro/Coal/Diesel/Biomass	690	67%	2000	2020-2037	Various
Electrica Angamos	Chile	Coal	558	67%	2011	2026-2037	Minera Escondida, Minera Spence, Quebrada Blanca
Cochrane	Chile	Coal	550	40%	2016	2030-2034	SQM, Sierra Gorda, Quebrada Blanca
Gener-SING [4]	Chile	Coal	277	67%	2000	2018-2037	Minera Escondida, Codelco, SQM, Quebrada Blanca
Electrica Ventanas [5]	Chile	Coal	272	67%	2010	2025	Gener
Electrica Campiche [6]	Chile	Coal	272	67%	2013	2020	Gener
Andes Solar	Chile	Solar	21	67%	2016	2037	Quebrada Blanca
Cochrane ES	Chile	Energy Storage	20	40%	2016		
Electrica Angamos ES	Chile	Energy Storage	20	67%	2011		
Norgener ES (Los Andes)	Chile	Energy Storage	12	67%	2009		
Chile Subtotal			*4,202*				
TermoAndes [7]	Argentina	Gas/Diesel	643	67%	2000	Short-term	Various
AES Gener Subtotal			*5,865*				
Alicura	Argentina	Hydro	1,050	100%	2000	2017	Various
Paraná-GT	Argentina	Gas/Diesel	845	100%	2001		
San Nicolás	Argentina	Coal/Gas/Oil	675	100%	1993		
Guillermo Brown [8]	Argentina	Gas/Diesel	576	—%	2016		
Los Caracoles [8]	Argentina	Hydro	125	—%	2009	2019	Energia Provincial Sociedad del Estado (EPSE)
Cabra Corral	Argentina	Hydro	102	100%	1995		Various
Ullum	Argentina	Hydro	45	100%	1996		Various
Sarmiento	Argentina	Gas/Diesel	33	100%	1996		
El Tunal	Argentina	Hydro	10	100%	1995		Various
Argentina Subtotal			*3,461*				
			9,326				

(1) Guacolda plants: Guacolda 1, 2, 3, 4, and 5 are unconsolidated entities for which the results of operations are reflected in *Net equity in earnings of affiliates*. The Company's ownership in Guacolda is held through AES Gener, a 67%-owned consolidated subsidiary. AES Gener owns 50% of Guacolda, resulting in an AES effective ownership in Guacolda of 33%.
(2) Electrica Santiago plants: Nueva Renca, Renca, Los Vientos and Santa Lidia. AES Gener announced the sale of this business in December 2017.
(3) Gener-SIC plants: Alfalfal, Laguna Verde, Laguna Verde Turbogas, Laja, Maitenes, Queltehues, Ventanas 1, Ventanas 2 and Volcán.
(4) Gener-SING plants: Norgener 1 and Norgener 2.
(5) Electrica Ventanas plant: Ventanas 3.

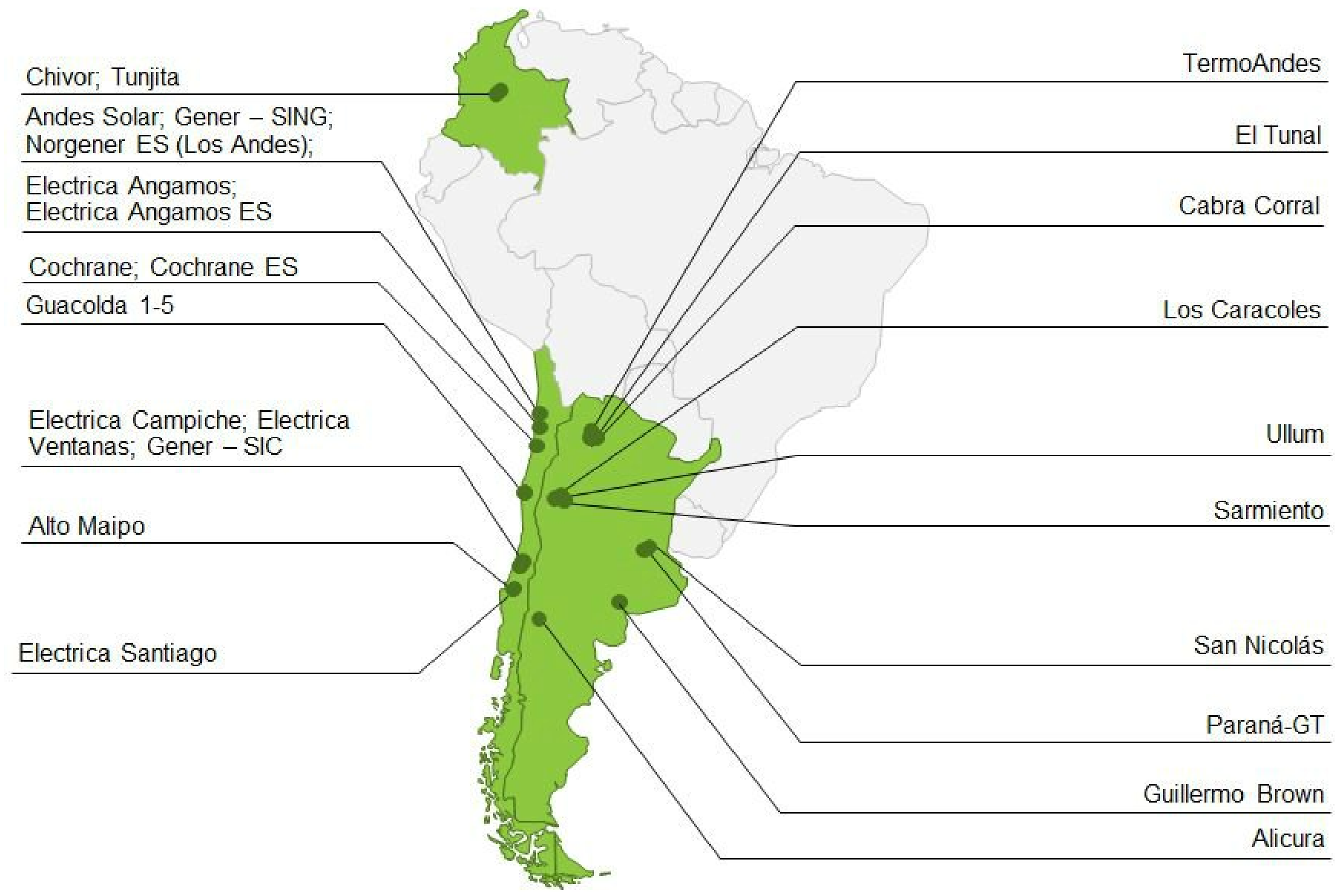
(6) Electrica Campiche plant: Ventanas 4.
(7) TermoAndes is located in Argentina, but is connected to both the SING in Chile and the SADI in Argentina.
(8) AES operates these facilities through management or O&M agreements and owns no equity interest in these businesses.

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

Business	Location	Fuel	Gross MW	AES Equity Interest	Expected Date of Commercial Operations
Alto Maipo	Chile	Hydro	531	62%	1H 2019 [1]

(1) This date is under review pending lender approval of an EPC contract. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Alto Maipo.*

The following map illustrates the location of our Andes facilities:



Andes Businesses

Chile

Regulatory Framework and Market Structure — Chile has operated a single power market, managed by CISEN, since November 2017. Previously, Chile had two main power systems, the SIC and SING, largely as a result of its geographic shape and size. The SIC served approximately 92% of the Chilean population, including the densely populated Santiago Metropolitan Region, representing 75% of the country's electricity demand. The SING, which mainly supplied mining companies, served about 6% of the Chilean population, representing 25% of Chile's electricity demand.

CISEN coordinates all generation and transmission companies previously in the SIC and SING. CISEN minimizes the operating costs of the electricity system, while maximizing service quality and reliability requirements. CISEN 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 SIC, thermoelectric generation is required to fulfill demand not satisfied by hydroelectric output and is critical to guaranteeing reliable and dependable electricity supply under dry hydrological conditions. In the SING, which includes the Atacama Desert, the driest desert in the world, thermoelectric capacity represents the majority of installed capacity as hydroelectric generation is not feasible. The fuels used for thermoelectric generation, mainly coal, diesel and LNG, are indexed to international prices. In 2017, the generation installed capacity in the Chilean market was composed primarily of the following:

	SIC	SING	CISEN
Thermoelectric	44%	84%	54%
Hydroelectric	38%	—	29%
Solar	8%	11%	9%
Wind	7%	3%	6%
Other	3%	2%	2%

In the SIC, where hydroelectric plants represent a large part of the system's installed capacity, hydrological conditions influence reservoir water levels and largely determine the dispatch of the system's hydroelectric and thermoelectric generation plants and, therefore, influence spot market prices. Precipitation in Chile occurs principally in the southern cone mostly from June to August, and is scarce during the remainder of the year. During 2017 spot prices were also affected by a 14% increase in installed renewable energy capacity, totaling 564 MW, bringing total installed capacity to 4,719 MW.

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. The electricity sector is divided into three segments: generation, transmission and distribution. Generally, generation and transmission growth is subject to market competition, while transmission operation and distribution are subject to price regulation. In July 2016, modifications to the Transmission Law were enacted. This law establishes that the transmission system will be completely paid for by the end-users, gradually allocating the costs on the demand side from 2019 through 2034.

All generators can sell energy through contracts with regulated distribution companies or directly to unregulated customers. Unregulated customers are customers whose connected capacity is higher than 2 MW. Customers with connected capacity between 0.5 MW and 2.0 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 contract. 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 U.S. dollars, although payments are made in Chilean pesos.

Business Description — In Chile, through AES Gener, we are engaged in the generation and supply of electricity (energy and capacity) in the CISEN. AES Gener is the second largest generation operator in Chile with installed capacity of 4,150 MW, excluding energy storage and TermoAndes, and a market share of approximately 18% as of December 31, 2017.

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

Our commercial strategy in Chile aims to maximize margin while reducing cash flow volatility. To achieve this, we contract a significant portion of our coal and hydroelectric baseload capacity under long-term agreements with a diversified customer base. Power plants not considered within our baseload capacity (higher variable cost units, mainly diesel and gas fired) sell energy on the spot market when operating during scarce system supply conditions, such as low hydrology and/or plant outages. In Chile, sales on the spot market are made only to other generation companies who are members of the CISEN at the system marginal cost.

AES Gener currently has long-term contracts, with an average remaining term of approximately 11 years, with regulated distribution companies and unregulated customers, such as mining and industrial companies. In general, these long-term contracts include both fixed and variable payments which are indexed to the CPI and the international price of coal. In some cases, the contracts include pass-through of fuel and regulatory costs, including changes in law.

In addition to energy payments, AES Gener also receives capacity payments to remain available during periods of peak demand. CISEN annually determines the capacity requirements for each power plant. The capacity price is fixed semiannually by the National Energy Commission and indexed to the CPI and other relevant indices.

The Chilean government allows the export of energy generated from plants in the SING to Argentina utilizing transmission lines owned by AES Gener.

Environmental Regulation — During 2016, the Environmental Ministry updated the Atmospheric

Decontamination Plans for the Santiago, Ventanas and Huasco regions. Our plants in these regions — Nueva Renca, Ventanas and Guacolda — are evaluating operational improvements and additional investments to comply with the new requirements. As of December 31, 2017, the regulator did not issue the decree that provides the framework and time line for these investments.

Chilean law requires every electricity generator to supply a certain portion of its total contractual obligations with NCREs. Generation companies are able to meet this requirement by constructing NCRE generation capacity (wind, solar, biomass, geothermal and small hydroelectric technology) or purchasing NCREs from qualified generators. Non-compliance with the NCRE requirements will result in fines. AES Gener currently fulfills the NCRE requirements utilizing AES Gener's solar and biomass power plants and by purchasing NCREs from other generation companies. AES Gener has also sold and contracted certain water rights to companies to construct small hydro projects to ensure longer term NCRE compliance. At present, AES Gener is in the process of negotiating additional NCRE supply contracts to meet the future requirements.

In September 2014 a new emission tax, or "green tax" was enacted, effective January 2017. Emissions of PM, SO_2, NO_x and CO_2 are monitored for plants with an installed capacity over 50 MW; these emissions are taxed. In the case of CO_2, the tax will be equivalent to $5 per ton emitted. PPAs originating from the SING have "change of law" clauses allowing the Company to pass the green tax costs to customers. Distribution PPAs originating from the SIC do not allow for the pass through of these costs; however, the costs can be passed through to unregulated customers. The Company is currently discussing the pass-through mechanism with each distribution customer.

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

- Dry hydrology scenarios
- Forced outages
- Changes in current regulatory rulings altering the ability to pass through or recover certain costs
- Fluctuations of the Chilean peso (our hedging strategy reduces this risk, but some residual risk remains)
- Tax policy changes
- Legislation promoting renewable energy and strengthening regulations on thermal generation assets
- Market price risk when re-contracting

Construction and Development — AES Gener continues to advance the construction of the 531 MW Alto Maipo run-of-the-river hydroelectric plant. Alto Maipo is the largest project in construction in the SIC market. When completed, it will include 74 km of tunnel works, two caverns, 17 km of transmission lines as part of the construction, and is 90% underground. Alto Maipo has two main contractors and covers three adjacent valleys in the Chilean Andes. The project currently employs approximately 4,500 people. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Alto Maipo.*

Colombia

Regulatory Framework and Market Structure — Electricity supply in Colombia is concentrated in one main system, the SIN, which encompasses one-third of Colombia's territory, providing electricity to 97% of the country's population. The SIN's installed capacity, primarily hydroelectric (70%) and thermal (29%), totaled 16,782 MW as of December 31, 2017. The marked seasonal variations in Colombia's hydrology result in price volatility in the short-term market. In 2017, 87% 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. The distinct activities of the electricity sector are governed by Colombian laws and the CREG. 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 Energetic Planning Unit, which is in charge of expansion 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 Colombian government and regulatory entity carried out various studies to improve the market. As a result, resolutions were issued in 2017 capping spot prices to reflect the true value of thermal plants; allowing small scale self-generation and distributed generation the option to sell excess energy to the grid; and a proposal to change the methodology for determining capacity payments for existing plants based on a new auction with the objective of reducing the reliability charges.

Business Description — We operate in Colombia through AES Chivor, a subsidiary of AES Gener, which owns a hydroelectric plant with an installed capacity of 1,000 MW, and Tunjita, a 20 MW run-of-river hydroelectric, both located approximately 160 km east of Bogota. AES Chivor's installed capacity accounted for approximately 6% of system capacity by the end of 2017. AES Chivor is dependent on hydrological conditions, which influence generation and spot prices of non-contracted generation in Colombia.

AES Chivor's commercial strategy aims to reduce margin volatility by selling a significant portion of expected generation by bidding in public auctions for one to three year contracts, mainly with distribution companies. The remaining generation is sold on the spot market to other generation and trading companies at the system marginal cost. Additionally, AES Chivor receives reliability payments to maintain plant availability 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 generation abilities. Maintaining the appropriate contract level, while maximizing revenue through the sale of excess generation, is key to Chivor's results of operations. Hedge levels at Chivor limit volatility in the underlying financial drivers. In addition to hydrology, financial results are driven by many factors, including, but not limited to:

- Forced outages
- Fluctuations of the Colombian peso
- Exposure to the spot market

Argentina

Regulatory Framework and Market Structure — Argentina has one main power system, the SADI, which serves 96% of the country. As of December 31, 2017, the installed capacity of the SADI totaled 36,505 MW. The SADI's installed capacity is composed primarily of thermoelectric generation (63%) and hydroelectric generation (32%).

Thermoelectric generation in the SADI is primarily natural gas. However, natural gas shortages in winter (June to August), lead to 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 spot market prices. Precipitation in Argentina occurs principally in the southern cone mostly from June to August.

Regulatory Framework — The Argentine regulatory framework divides the electricity sector into generation, transmission and distribution. The wholesale electric market is made up 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 Ministry of Energy and Mining, through the Energy Secretariat, regulates system framework and grants concessions or authorizations for sector activities. In Argentina, the regulator establishes the prices for electricity and fuel and adjusts them periodically for inflation, changes in fuel prices and other factors. In these cases, our businesses are particularly sensitive to changes in regulation.

The Argentine electric market is an "average cost" system, with generators being compensated for fixed costs and non-fuel variable costs plus a rate of return. All fuels, except coal, are to be provided by CAMMESA. Thermoelectric natural gas plants, such as TermoAndes, are not subject to CAMMESA fuel purchases and are able to purchase gas directly from the producers.

Argentina's new administration continues introducing regulatory improvements with the intention to normalize the energy sector. Among others, Resolution 19/2017 was enacted to set higher tariffs, denominated in USD, for energy and capacity prices. The Resolution also ceased non-cash retention of margins. Likewise, long term USD denominated PPAs have been awarded to develop 9.4 GW of new capacity (thermal and renewable) through the execution of competitive auctions. During 2017, the government has continued increasing residential and industrial tariffs in order to reduce the system deficit aiming to have all subsidies removed by the end of 2019.

AES Argentina has contributed certain accounts receivable to fund the construction of new power plants under FONINVEMEM agreements. These receivables accrue interest and are collected in monthly installments over 10 years once the related plants begin to operate. AES Argentina has three FONINVEMEM funds related to operational plants under which payments are being received. AES Argentina will receive a pro rata ownership interest in these plants once the accounts receivables have been fully repaid. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Long-Term Receivables* and Note 6.—*Financing Receivables* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further discussion of receivables in Argentina.

Business Description — As of December 31, 2017, AES Argentina operates 4,104 MW, representing 11% of the country's total installed capacity. The installed capacity in the SADI includes the TermoAndes plant, a subsidiary of AES Gener, which is connected both to the SADI and the Chilean SING markets. AES Argentina has a diversified generation portfolio.

AES Argentina primarily sells its energy in the wholesale electric market where prices are largely regulated. In 2017, approximately 93% of the energy was sold in the wholesale electric market and 7% was sold under contract, as a result of contract sales made by TermoAndes.

All thermoelectric facilities not subject to fuel procurement from CAMMESA, including the portion of TermoAndes plant committed to Energy Plus contracts, are able to use natural gas and receive gas supplied from Argentine sources. In recent years, gas supply restrictions in Argentina, particularly during the winter season, have affected the operation of certain plants, such as the TermoAndes plant.

Since December 2015, foreign currency controls were lifted, allowing the Argentine peso to float under the administration of Argentinian Central Bank. Over the course of 2017, the Argentine peso devalued by approximately 17%.

Tax Regulation — On December 29, 2017, Law 27430 was enacted in Argentina, which introduced a tax reform with several changes in the Argentine tax system, to be effective on January 1, 2018. This tax reform will reduce the statutory corporate tax rate of companies from 35% to 30% in 2018 and 2019, and 25% from 2020 onward. The law also eliminates the Equalization Tax on the distribution of earnings generated after January 1, 2018. The Equalization Tax is to be replaced with a withholding tax on dividends at the rate of 7% for 2018 and 2019, and 13% from 2020 onward.

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
- Timely collection of FONINVEMEM installment and outstanding receivables (See Note 6.—*Financing Receivables* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further discussion)
- Gas prices for contracted generation (Energy Plus)

Brazil SBU

Our Brazil SBU operates three generation businesses. Tietê is a publicly listed company in Brazil. AES controls and consolidates Tietê through its 24% economic interest.

Generation — Operating installed capacity of our three generation businesses totals 3,684 MW. The following table lists our Brazil SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Tietê [(1)]	Brazil	Hydro	2,658	24%	1999	2029	Various
Alto Sertão II	Brazil	Wind	386	24%	2017	2033-2035	
Tietê Subtotal			*3,044*				
Uruguaiana	Brazil	Gas	640	46%	2000		
			3,684				

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

The following map illustrates the location of our Brazil facilities:

Brazil Businesses

Brazil Utility

Business Description — Eletropaulo distributes electricity to the greater São Paulo area, Brazil's main economic and financial center. Eletropaulo holds a 30-year concession that expires in 2028. AES owns 17% of the economic interest in Eletropaulo. In November 2017, Eletropaulo converted its preferred shares into ordinary shares and transitioned the listing of those shares into the Novo Mercado, which is a listing segment of the Brazilian stock exchange with the highest standards of corporate governance. Upon conversion of the preferred shares into ordinary shares, AES no longer controlled Eletropaulo and accounted for its ownership interest as an equity method investment. In December 2017, all the criteria were met for Eletropaulo to be classified as a discontinued operation.

Brazil Generation

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

The ONS is responsible for managing the operation of the national grid. The ONS dispatches generators based on hydrological conditions, reservoir levels, electricity demand, fuel prices and thermal generation availability. The consequences of unfavorable hydrology are (i) thermal plants become more expensive to dispatch in the system, (ii) the need for hydro plants to purchase energy in the spot market to fulfill their contractual obligations and (iii) high spot prices. Given the importance of hydro generation in the country, the ONS sometimes reduces dispatch of hydro facilities and increases dispatch of thermal facilities to maintain reservoir levels in the system.

A mechanism known as the MRE was created under ONS to share hydrological risk across MRE hydro generators. If the hydro plants generate less than the total MRE physical guarantee, the hydro generators may need to purchase energy in the short-term market. When total hydro generation is higher than the total MRE physical guarantee, the surplus is proportionally shared among its participants and they may sell the excess energy on the spot market.

Brazil has installed capacity of 156,436 MW, which is primarily hydroelectric (64%) and thermal (17%).

Business Description — Tietê has a portfolio of 12 hydroelectric power plants in the state of São Paulo with total installed capacity of 2,658 MW. Tietê represents approximately 10% of the total generation capacity in the state of São Paulo. Tietê operates under a 30-year concession expiring in 2029. AES owns 24% of Tietê and is the controlling shareholder and manages and consolidates this business. Tietê's strategy is to contract most of its physical guarantee requirements and sell the remaining portion in the spot market. The commercial strategy is reassessed periodically according to changes in market conditions, hydrology and other factors. Tietê generally sells available energy through medium-term bilateral contracts.

Under the concession agreement, Tietê is required to increase its capacity in the state of São Paulo by 15% (or 400 MW). In 2017, Tietê acquired two solar plants and was successful in a bid to develop a third solar project in the state of São Paulo, totaling 75% of the obligation. These assets are not subject to return at the end of the concession. Also in 2017, Tietê acquired Alto Sertão II Wind Complex (“Alto Sertão II”) located in the state of Bahia, with an installed capacity of 386 MW. Alto Sertão II is subject to 20-year PPAs expiring between 2033 and 2035. Through its ownership of Tietê, AES owns a 24% economic interest in Alto Sertão II.

Uruguaiana is a 640 MW gas-fired combined cycle power plant located in the town of Uruguaiana in the state of Rio Grande do Sul. AES manages and has a 46% economic interest in the plant. The plant's operations have been largely suspended due to the unavailability of gas. The plant operated for short periods of time in 2013, 2014 and 2015 when short-term supply of LNG was sourced for the facility. The plant did not operate in 2016 or 2017. AES has evaluated several alternatives to bring gas supply on a competitive basis to Uruguaiana. One of the challenges is the capacity restrictions on the Argentinean pipeline, especially during the winter season when gas demand in Argentina is very high. Uruguaiana continues to work toward securing gas on a long-term basis.

Key Financial Drivers — As the system is highly dependent on hydroelectric generation, electricity pricing is driven by hydrology in Brazil. Plant availability is also a significant financial driver as in times of high hydrology AES is more exposed to the spot market. The availability of gas is also a driver for continued operations at Uruguaiana. Tietê's financial results are driven by many factors, including, but not limited to:

- Hydrology, impacting quantity of energy generated in MRE
- Demand growth
- Re-contracting price
- Asset management and plant availability
- Cost management
- Ability to execute on its growth strategy

Construction and Development — As part of the initiative to pursue opportunities in renewable generation, Tietê has invested in three special purpose entities slated to construct photovoltaic power plants with a total projected capacity of 91 MW, subject to 20-year PPAs. Commercial operation is expected by the end of 2018.

MCAC SBU

Our MCAC SBU has a portfolio of distribution businesses and generation facilities, including renewable energy, in five countries, with a total capacity of 3,381 MW and distribution networks serving 1.4 million customers as of December 31, 2017.

Generation — The following table lists our MCAC SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
DPP (Los Mina)	Dominican Republic	Gas	358	85 %	1996	2022	CDEEE
Andres	Dominican Republic	Gas	319	85 %	2003	2022	Ede Norte/Ede Este/Ede Sur/Non-Regulated Users
Itabo [(1)]	Dominican Republic	Coal	295	43 %	2000	2022	Ede Norte/Ede Este/Ede Sur
Andres ES	Dominican Republic	Energy Storage	10	85 %	2017		
Los Mina DPP ES	Dominican Republic	Energy Storage	10	85 %	2017		
Dominican Republic Subtotal			*992*				
AES Nejapa	El Salvador	Landfill Gas	6	100 %	2011	2035	CAESS
Moncagua	El Salvador	Solar	3	100 %	2015	2035	EEO
El Salvador Subtotal			*9*				
Merida III	Mexico	Gas	505	75 %	2000	2025	Comision Federal de Electricidad
Termoelectrica del Golfo (TEG)	Mexico	Pet Coke	275	99 %	2007	2027	CEMEX
Termoelectrica del Penoles (TEP)	Mexico	Pet Coke	275	99 %	2007	2027	Penoles
Mexico Subtotal			*1,055*				
Bayano	Panama	Hydro	260	49 %	1999	2030	Electra Noreste/Edemet/Edechi/Other
Changuinola	Panama	Hydro	223	90 %	2011	2030	AES Panama
Chiriqui-Esti	Panama	Hydro	120	49 %	2003	2030	Electra Noreste/Edemet/Edechi/Other
Estrella de Mar I	Panama	Heavy Fuel Oil	72	49 %	2015	2020	Electra Noreste/Edemet/Edechi/Other
Chiriqui-Los Valles	Panama	Hydro	54	49 %	1999	2030	Electra Noreste/Edemet/Edechi/Other
Chiriqui-La Estrella	Panama	Hydro	48	49 %	1999	2030	Electra Noreste/Edemet/Edechi/Other
Panama Subtotal			*777*				
Puerto Rico	US-PR	Coal	524	100 %	2002	2027	Puerto Rico Electric Power Authority
Ilumina	US-PR	Solar	24	100 %	2012	2032	Puerto Rico Electric Power Authority
Puerto Rico Subtotal			*548*				
			3,381				

(1) Itabo plants: Itabo complex (two coal-fired steam turbines and one gas-fired steam turbine).

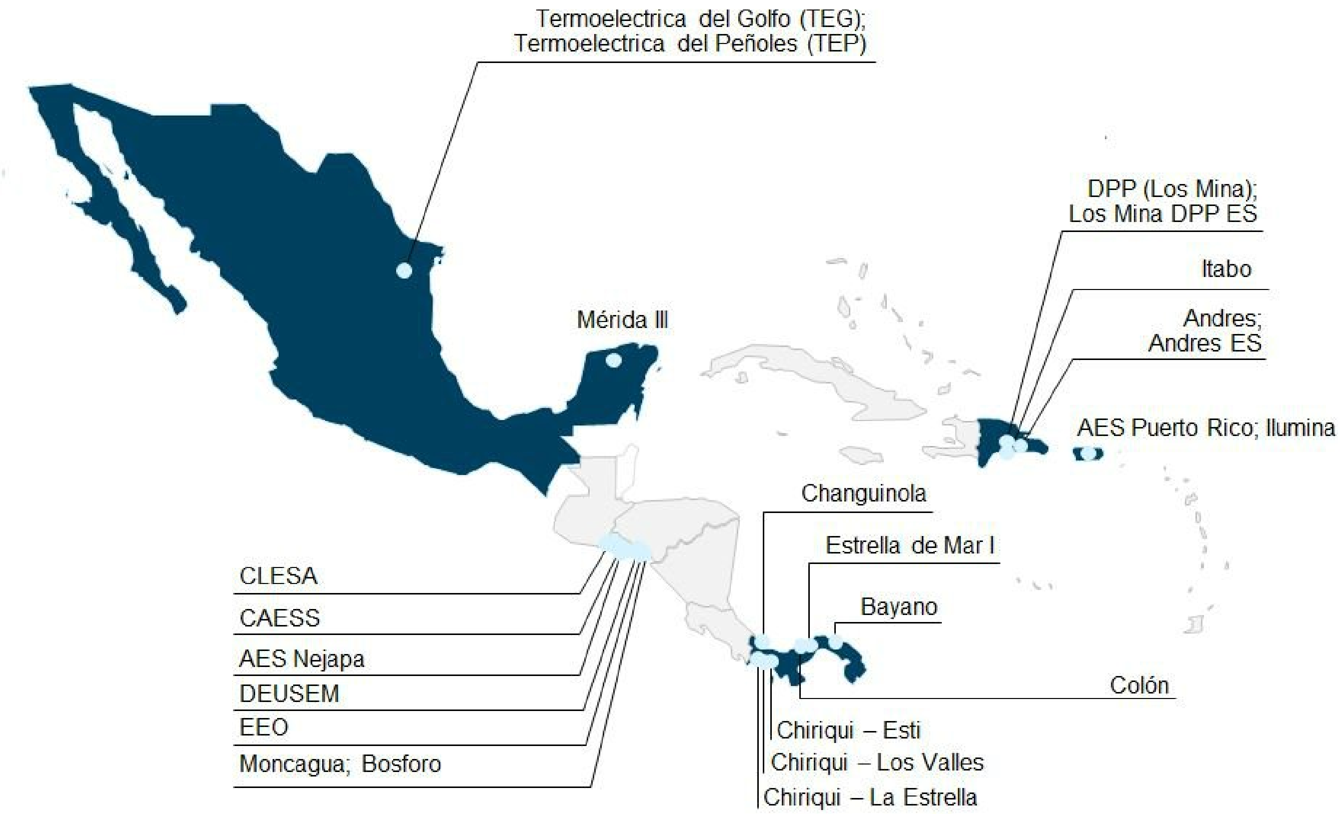
Under construction — The following table lists our plants under construction in the MCAC SBU:

Business	Location	Fuel	Gross MW	AES Equity Interest	Expected Date of Commercial Operations
Bosforo	El Salvador	Solar	30	100%	1H-2H 2018
Colón	Panama	Gas	380	50%	2H 2018
			410		

Utilities — Our distribution businesses are located in El Salvador and distribute power to 1.4 million people in the country. These businesses consist of four companies, each of which operates in defined service areas. The following table lists our MCAC utilities:

Business	Location	Approximate Number of Customers Served as of 12/31/2017	GWh Sold in 2017	AES Equity Interest	Year Acquired or Began Operation
CAESS	El Salvador	599,000	2,213	75%	2000
CLESA	El Salvador	398,000	898	80%	1998
DEUSEM	El Salvador	80,000	133	74%	2000
EEO	El Salvador	307,000	577	89%	2000
		1,384,000	3,821		

The following map illustrates the location of our MCAC facilities:



MCAC Businesses

Dominican Republic

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

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

- The National Energy Commission drafts and coordinates the legal framework and regulatory legislation. They propose and adopt policies and procedures to implement best practices, support the proper functioning and development of the energy sector, and promote investment.
- The Superintendence of Electricity's main responsibilities include monitoring compliance with legal provisions, rules, and technical procedures governing generation, transmission, distribution and commercialization of electricity. In addition, they monitor behavior in the electric market in order to avoid monopolistic practices. In addition to the two agencies responsible for monitoring compliance with the General Electricity Law, the Industrial and Commerce Ministry supervises commercial and industrial activities in the Dominican Republic as well as the fuels and natural gas commercialization to the end users.

The Dominican Republic has one main interconnected system with approximately 3,692 MW of installed capacity, composed primarily of thermal (79%), hydroelectric (17%) and wind (4%) generation plants/farms.

Business Description — AES Dominicana consists of three operating subsidiaries, Itabo, Andres and Los Mina. With a total of 992 MW of installed capacity, AES has 26% of the system capacity and supplies approximately 46% of energy demand via these generation facilities. AES has a strategic partnership with the Estrella and Linda Groups ("Estrella-Linda"), a consortium of two leading Dominican industrial groups that manage a diversified business portfolio.

Itabo is 42.5% owned by AES. Itabo owns and operates two thermal power generation units with a total of 295 MW of installed capacity. Itabo's PPAs with government-owned distribution companies expired in July 2016. The

Dominican Corporation of State Electrical Companies sponsored a bidding process, which was awarded in April 2017 for a total of 196 MW of installed capacity and secured supply and competitive pricing for actual and future distribution energy requirements.

Andres and Los Mina are owned 85% by AES. Andres has a combined cycle natural gas turbine, an energy storage solution and generation capacity of 329 MW as well as the only LNG import facility in the country, with 160,000 cubic meters of storage capacity. Los Mina has a combined cycle with two natural gas turbines, an energy storage solution and generation capacity of 368 MW. Both Andres and Los Mina have in aggregate 697 MW of installed capacity, of which 625 MW is mostly contracted until 2022 with government-owned distribution companies and large customers.

AES Dominicana has a long-term LNG purchase contract through 2023 for 33.6 trillion btu/year with a price linked to NYMEX Henry Hub. The LNG contract terms allow delivery to various markets in Latin America. These plants capitalize on the competitively-priced LNG contract by selling power where the market is dominated by fuel oil-based generation. Andres has a long-term contract to sell re-gasified LNG to industrial users within the Dominican Republic using compression technology to transport it within the country thereby capturing demand from industrial and commercial customers.

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 the spot sales for both Andres and Itabo).
- Contracting levels and the extent of capacity awarded.
- Supply shortages in the near term (next two to three years) may provide opportunities for short term upside, but new generation is expected to come online beginning 2018.
- Additional sales derived from domestic natural gas demand are expected to continue providing income and growth based on the entry of future projects and the fees from the infrastructure service.

El Salvador

Regulatory Framework and Market Structure — El Salvador national electric market is composed of generation, distribution, transmission and marketing businesses, as well as 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 get affordable rates. The energy sector is governed by the General Electricity Law which defines two regulatory entities responsible for monitoring its compliance:

- The National Energy Council 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 ("SIGET") regulates the market and sets consumer prices. SIGET, jointly with the distribution companies in El Salvador, completed the tariff reset process in December 2017 and developed the tariff calculation applicable from 2018 until 2022.

El Salvador has a national electric grid which interconnects with Guatemala and Honduras. The sector has approximately 1,882 MW of installed capacity, composed primarily of thermal (40%), hydroelectric (29%), geothermal (11%), biomass (13%), solar (5%) and other renewable (2%) generation plants/farms.

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 4,124 GWh of the wholesale market energy purchases during 2017, or about 65% market share.

Construction and Development — As part of the initiative to pursue opportunities in renewable generation, AES El Salvador has entered into a joint venture with Corporacion Multi-Inversiones, a Guatemalan investment group, to develop, construct, and operate Bosforo, a 100 MW solar farm with an estimated cost of $158 million. 10 MW of the project are under construction and expected to become operational during the first half of 2018. The energy produced by this project will be contracted directly by AES' utilities in El Salvador.

Panama

Regulatory Framework and Market Structure — The Panamanian power sector is composed of three distinct operating business units: generation, distribution and transmission. Generators can enter into long-term PPAs with distributors or unregulated consumers. In addition, generators can enter into alternative supply contracts with each other. Outside of the PPA market, 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 SNE has the responsibilities of planning, supervising and controlling policies of the energy sector within Panama. With these responsibilities, the SNE proposes laws and regulations to the executive agencies that regulate the procurement of energy and hydrocarbons for the country.
- The regulator of public services, known as the ASEP, is an autonomous agency of the government. ASEP is responsible for the control and oversight of public services, including electricity, the transmission and distribution of natural gas utilities, and the companies that provide such services.
- The National Dispatch Center implements 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 by the National Dispatch Center regardless of contractual arrangements.

Panama's current total installed capacity is 2,983 MW, composed primarily of hydroelectric (57%) and thermal (38%) generation.

Business Description — AES owns and operates five hydroelectric plants and one thermoelectric power plant, Estrella del Mar I, representing 705 MW and 72 MW of hydro and thermal capacity, respectively and 26% of the total installed capacity in Panama.

The majority of hydroelectric plants in Panama are based on run-of-river technology, with the exception of the 260 MW Bayano plant. Hydrological conditions have an important influence on profitability. Variations in hydrology can result in excess or a shortfall in energy production relative to our contract obligations. Hydro generation is generally in a shortfall position during low inflows from January through May, AES Panama may purchase energy in the short-term market to cover contractual obligations. During the remainder of the year, energy generation is generally in excess of contractual commitments, excess generation is sold on the short-term market.

A portion of the PPAs with distribution companies will expire in December 2018, reducing the total contracted capacity in Panama from 496 MW to 430 MW. Another portion contracted through Estrella del Mar I will expire in June 2020, reducing the total contracted capacity to 350 MW through December 2030.

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

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

Construction and Development — In August 2015, AES executed a partnership agreement with Deeplight Corporation, a minority partner, to construct, operate, and maintain a natural gas power generation plant and a liquefied natural gas terminal, in order to purchase and sell energy and capacity as well as commercialize natural gas and other ancillary activities related to natural gas. As of December 31, 2017, amounts capitalized include $666 million recorded in construction-in-progress and the project is scheduled to initiate operations in the second half of 2018.

Mexico

Regulatory Framework and Market Structure — Mexico has a single electric grid, the National Electricity System, covering all of Mexico's territory through the Interconnected National Electricity, Baja California and Southern Baja California Systems. The market comprises generation, transmission, distribution and commercialization segments.

Three main agencies, in addition to the Ministry of Energy, are responsible for monitoring compliance with the Electric Industry Law:

- The Energy Regulatory Commission is responsible for the establishment of directives, orders, methodologies and standards oriented to regulate the electric and fuel markets.

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

Mexico has an installed capacity totaling 74 GW with a generation mix primarily comprising of thermal (71%) and hydroelectric (17%) plants.

Business Description — AES has 1,055 MW of installed capacity in Mexico. The TEG and TEP pet coke-fired plants, located in Tamuin, San Luis Potosi, supply power to their offtakers under long-term PPAs expiring in 2027 with a 90% availability guarantee. TEG and TEP secure their fuel under a long-term contract.

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

AES has partnered in a joint venture with Grupo BAL to co-invest in power and related infrastructure projects in Mexico, focusing on renewable and natural gas generation. The first development, a 306 MW wind project, expects to begin construction in the first half of 2018.

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

- As the companies are fully contracted, improved operational performance provides additional benefits, including performance incentives and/or excess energy sales.
- Changes in the Locational Marginal Price and the Transmission High Tension Tariff.

Puerto Rico

Regulatory Framework and Market Structure — Puerto Rico has a single electric grid managed by PREPA, a state-owned entity that supplies virtually all of the electric power consumed in Puerto Rico and generates, transmits and distributes electricity to 1.5 million customers. The Puerto Rico Energy Commission ("PREC") is the main regulatory body. The commission approves wholesale and retail rates, sets efficiency and interconnection standards, and oversees PREPA's compliance with Puerto Rico's renewable portfolio standard.

Puerto Rico's electricity is 98% produced by thermal plants (47% from petroleum, 34% from natural gas, 17% from coal).

Business Description — AES Puerto Rico owns and operates a coal-fired cogeneration plant and a solar plant of 524 MW and 24 MW, respectively, representing approximately 9% of the installed capacity in Puerto Rico. Both plants have long-term PPAs expiring in 2027 and 2032, respectively, with PREPA. 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 PPA with PREPA.

Eurasia SBU

Generation — Our Eurasia SBU has generation facilities in seven countries. Operating installed capacity totaled 6,143 MW. The following table lists our Eurasia SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Maritza	Bulgaria	Coal	690	100%	2011	2026	Natsionalna Elektricheska
St. Nikola	Bulgaria	Wind	156	89%	2010	2025	Natsionalna Elektricheska
Bulgaria Subtotal			*846*				
OPGC [1]	India	Coal	420	49%	1998	2026	GRID Corporation Ltd.
India Subtotal			*420*				
Amman East	Jordan	Gas	381	37%	2009	2033	National Electric Power Company
IPP4	Jordan	Heavy Fuel Oil	250	36%	2014	2039	National Electric Power Company
Jordan Subtotal			*631*				
Elsta [1][2]	Netherlands	Gas	630	50%	1998	2018	Dow Benelux/Delta/ Nutsbedrijven/Essent Energy
Netherlands ES	Netherlands	Energy Storage	10	100%	2015		
Netherlands Subtotal			*640*				
Masinloc [3]	Philippines	Coal	630	51%	2008	Mid- and long-term	Various
Masinloc ES [3]	Philippines	Energy Storage	10	51%	2016		
Philippines Subtotal			*640*				
Ballylumford	United Kingdom	Gas	1,015	100%	2010	2023	Power NI/Single Electricity Market (SEM)
Kilroot [4]	United Kingdom	Coal/Oil	701	99%	1992		Single Electricity Market (SEM)
Kilroot ES	United Kingdom	Energy Storage	10	100%	2015		
United Kingdom Subtotal			*1,726*				
Mong Duong 2	Vietnam	Coal	1,240	51%	2015	2040	EVN
Vietnam Subtotal			*1,240*				
			6,143				

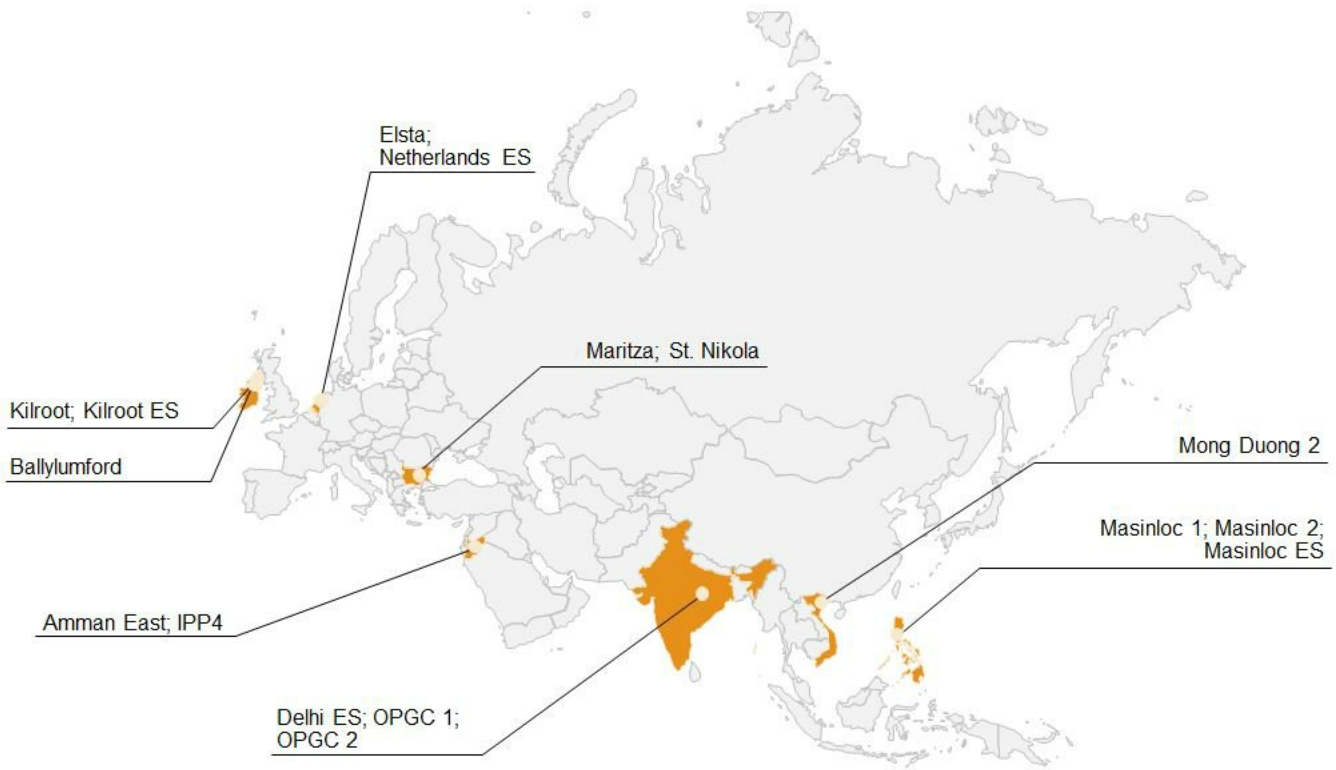
(1) Unconsolidated entity, the results of operations of which are reflected in Equity in Earnings of Affiliates.
(2) Plant will be sold upon expiration of the PPA in September 2018.
(3) Announced the sale of this business in December 2017.
(4) Includes Kilroot Open Cycle Gas Turbine.

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

Business	Location	Fuel	Gross MW	AES Equity Interest	Expected Date of Commercial Operations
OPGC 2 [1]	India	Coal	1,320	49%	2H 2018
Delhi ES	India	Energy Storage	10	50%	2H 2018
			1,330 [2]		

(1) Unconsolidated entity, accounted for as an equity affiliate.
(2) In December 2017, AES announced the sale of Masinloc. As such, 335 MW under construction at Masinloc 2 has been excluded from this table.

The following map illustrates the location of our Eurasia facilities:



Eurasia Businesses

Bulgaria

Regulatory Framework and Market Structure — The electricity sector in Bulgaria allows both regulated and competitive segments. NEK, the state-owned electricity public supplier and energy trading company, acts as a single buyer and seller for all regulated transactions on the market. Electricity outside the regulated market trades at bilaterally negotiated prices in an open market or on the day-ahead IBEX market. In March 2017, IBEX introduced an intra-day market platform. In addition, IBEX launched a platform for trading long-term contracts in Q4 2016. Effective January 1, 2018 all electricity outside regulated quotas may only be traded via the IBEX platform. Bulgaria is working with the European Commission and the World Bank on a model that will allow the gradual phase out of regulated energy prices.

Bulgaria's power sector is supported by a diverse generation mix, a stable regulatory environment, universal access to the grid, and numerous cross-border connections in neighboring countries. In addition, it plays an important role in the energy balance on the Balkan region.

Bulgaria has 13 GW of installed capacity enabling the country to meet and exceed domestic demand and export energy. Installed capacity is 39% coal-fired and 16% nuclear.

Business Description — Our Maritza plant is a 690 MW lignite fuel thermal power plant commissioned in June 2011. Maritza's entire power output is contracted with NEK under a 15-year PPA, expiring in May 2026.

AES also owns an 89% economic interest in the St. Nikola wind farm with 156 MW of installed capacity. St. Nikola was commissioned in March 2010. Its entire power output is contracted with NEK under a 15-year PPA expiring in March 2025.

Our plants in Bulgaria operate under long-term PPAs with NEK, which has previously experienced liquidity issues. In April 2016, NEK paid Maritza its overdue receivables in exchange for amending the PPA and reducing the capacity payment to Maritza by 14% through the remaining PPA term. Maritza has experienced timely collection of outstanding receivables from NEK since May 2016. However, NEK's liquidity position remains subject to political conditions and regulatory changes in Bulgaria.

The DG Comp is reviewing NEK's PPA with Maritza pursuant to the European Commission's state aid rules.

Maritza believes that its PPA is legal and in compliance with all applicable laws. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Regulatory.*

Key Financial Drivers — Both businesses, Maritza and St. Nikola, operate under PPA contracts. For the duration of the PPA, financial results are driven by many factors, including, but not limited to:

- Regulatory changes to the Bulgaria power market
- Results of the DG Comp review
- The availability of the operating units
- The level of wind resources for St. Nikola
- NEK's ability to meet the payment terms of the PPA contract

United Kingdom

Regulatory Framework and Market Structure — The electricity sector in Northern Ireland is operated by the SEM. It is based on a gross mandatory pool within which all generators with capacity higher than 10 MW must trade the physical delivery of power. Generators are centrally dispatched based on merit order and physical constraints of the system.

In addition, the SEM has a capacity payment mechanism to ensure that sufficient generating capacity is offered to the market. The capacity payment is derived from a regulated Euro-based capacity payment pool, established a year ahead by the regulatory authority. Capacity payments are based on the expected availability of a unit and are subject to volatility due to seasonal influences, demand, and the actual generation available over each trading period. In the second quarter of 2018 regulatory authorities are expected to update the market framework to reflect the integration of the SEM day-ahead and intra-day markets with EU energy markets, introduce a new competitive capacity auction, and revise arrangements for system services to incentivize flexibility. The market will be renamed I-SEM (Integrated Single Electricity Market) to reflect these changes.

Northern Ireland's power sector is supported by a diverse generation mix, a stable regulatory environment, universal access to the grid, and connections between Northern and Southern Ireland and the UK. Installed capacity in the SEM is 49% gas fired and 26% from renewable sources, resulting in sensitivity to gas prices relative to order of merit. SEM has also set a target of 40% renewable generation by 2020.

Business Description — AES has two generation plants in the United Kingdom, both of which are located in Northern Ireland within the Greater Belfast region. Kilroot is a 701 MW coal-fired merchant plant, with an additional 10 MW of energy storage, that bids into the I-SEM. Kilroot's coal fired units failed to clear in the first I-SEM capacity auction process. Consequently, AES announced its intent to shut down the coal units on or before May 31, 2018, pending the results of an assessment by the regulator to determine the long term needs of the Northern Ireland power grid. Ballylumford is a 1,015 MW gas-fired plant, of which 600 MW is contracted under a PPA with Power NI Power Procurement Business expiring in 2023. The 415 MW remaining capacity is bid into the SEM market, with 310 MW subject to a supplemental Local Reserve Services Agreement with the system operator. One of Ballylumford's B-station units failed to clear the aforementioned I-SEM capacity auction; as a result, AES intends to retire that unit at the end of December 2018.

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

- Regulatory changes to the market structure and payment mechanisms
- Investments to maintain compliance with European Union environmental legislation
- Availability of the operating units and order of merit
- Commodity prices (gas, coal and CO_2) and sufficient market liquidity to hedge prices in the short-term
- Electricity demand in the SEM (including impact of wind generation)

Kazakhstan

Regulatory Framework and Market Structure — The Kazakhstan government has grouped generators into fifteen groups based on a number of factors, including plant type and fuel used. Each group has a fixed tariff-cap level and all generators must sell electricity at or below their respective tariff-cap levels.

Business Description — AES operated four plants with a total capacity of 2,776 MW. Our two hydroelectric plants, representing 1,033 MW, were operated under a concession agreement until early October 2017, when the plants were transferred back to the Republic of Kazakhstan. The remaining 1,743 MW coal-fired capacity was sold in the second quarter of 2017.

Jordan

Regulatory framework and market structure — The Jordan electricity transmission market is a single-buyer model with the state owned NEPCO responsible for transmission. NEPCO generally enters into long term power purchase agreements with IPP's to fulfill energy procurement requests from distribution utilities. The sector is prioritizing renewable energy development, with 2,200 MW of renewable energy installed capacity expected by year 2020, 700 MW of which was already connected to the grid.

Business Description — In Jordan, AES has a 37% controlling interest in Amman East, a 381 MW oil/gas-fired plant fully contracted with the national utility under a 25-year PPA expiring in 2033, and a 36% controlling interest in the IPP4 plant, a 250 MW oil/gas-fired peaker plant which commenced operations in July 2014, fully contracted with the national utility until 2039. We consolidate the results in our operations as we have controlling interest in these businesses.

Construction and Development — AES, in conjunction with Mitsui & Co of Japan and NEBRAS Power of Qatar, have signed an agreement to construct a 52 MW solar project in Jordan. Construction of the plant has not begun, but is expected to be completed mid-2019 to coincide with the start of a PPA to provide energy to NEPCO through 2038.

India

Regulatory framework and Market Structure — The power sector is largely dominated by state and central government-owned generation and distribution utilities. Electricity is generally sold to state utilities under long-term PPAs. The tariffs are fixed on yearly basis by the Electricity Regulatory Commissions of the Centre and the State(s) or determined through competitive bidding process. Orissa Electricity Regulatory Commission ("OERC") regulates the electricity purchase and procurement process for the Distribution Licensees, including the price at which the electricity from generating companies shall be procured for supply within the state of Orissa. OERC also facilitates interstate transmission and wheeling of electricity. OERC is guided by the National Electricity Policy, National Electricity Plan and Tariff Policy issued by the Government of India.

The power sector in India is composed of coal, gas, hydroelectric, renewable and nuclear energy. Total installed capacity as of December 31, 2017 was 331 GW, of which 66% is thermal generation. Renewable energy is adding capacity at a rapid pace and currently represents 18% of the total installed capacity.

Business Description — OPGC is a 420 MW coal-fired generation facility located in the state of Odisha. OPGC has a 30-year PPA with GRIDCO Limited, a state utility, expiring in 2026. OPGC is an unconsolidated entity and results are reported as *Net equity in earnings of affiliates* on our Consolidated Statements of Operations.

Construction and Development — AES has one 1,320 MW coal-fired project under construction and expected to begin operations by the end of 2018. As of December 31, 2017, total capitalized costs at the project level were $1.1 billion. Currently, 50% of the expansion capacity, or 660 MW, is contracted with GRIDCO for a period of 25 years. The remaining 50% of the generation capacity is proposed to be offered to GRIDCO under a new PPA.

Environmental Regulation — The Ministry of Environment, Forest and Climate Change in India amended the Environment (Protection) Rules with stricter emission limits for thermal power plants via their notification issued in December 2015. All existing plants installed before December 31, 2003 are required to meet revised emission limits within two years and any new thermal power plants that will be operational from January 1, 2017 are required to operate with the revised emission limits. As a result of this amendment, FGD systems need to be installed in the existing OPGC units to comply with the new SO_2 emissions requirements, and new design options modifications to the schedule of the expansion project have been evaluated. As these amendments will require substantial investment to meet the revised environmental guidelines across the public and private power sectors in India, amendments and implementation time lines are still under review by the Ministry of Power, Government of India. We believe the cost of complying with the new environmental regulations for particulate matters, water consumption, So_x and No_x limits will be a pass-through in the GRIDCO tariff for both the existing and expansion units.

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

- Operating performance of the facility
- Regulatory and environmental policy changes
- Tariff determination by the OERC

Philippines

Regulatory Framework and market structure — The Philippines' power sector is divided into generation, transmission, distribution and supply. Generation and supply are open and competitive sectors, while transmission and distribution are regulated sectors. The ERC is an independent regulatory body performing administrative and other functions for the electric industry.

The Philippine power market is divided into three grids representing the three major island groups, Luzon, Visayas and Mindanao. Luzon, which includes Manila, the country's largest island, has limited interconnection with Visayas, and represents 86% of the total demand of both regions. Luzon and Visayas together have an installed capacity of approximately 18 GW. For Luzon, the largest generation sources are 50% coal and 29% natural gas.

The sale of power is conducted primarily through medium- or long-term bilateral contracts between generation companies and distribution utilities which are approved by the ERC. Distribution utilities and electric cooperatives are allowed to pass on to their end-users the bilateral contract rates, including WESM purchases, as approved by the ERC.

Business Description — The Masinloc plant is a 630 MW gross coal-fired plant located in Zambales, Philippines, is interconnected to the Luzon Grid, and is 51% owned by AES. More than 95% of Masinloc's current peak capacity is contracted through bilateral contracts. 430 MW is contracted with Meralco, the largest distribution company in the Philippines, under a PPA expiring in 2019. Following an ERC Order limiting power supply agreement extensions to one year, a supplemental PPA extending the contract with Meralco an additional three years was submitted for approval with the ERC. Masinloc's remaining contracts on existing units expire between 2018 and 2026. Masinloc has been granted a retail electricity supplier license from the ERC and currently markets power to contestable customers. Unlike Masinloc's contracts with distribution utilities, it's contract with contestable customers do not require ERC approval to be implemented. On December 17, 2017, the Company entered into an agreement to sell its Masinloc business. Closing is expected during the first half of 2018 subject to certain regulatory approvals.

Construction and Development — AES is constructing a 335 MW gross unit expansion to the Masinloc plant. The total capitalized cost as of December 31, 2017 is $394 million. The expansion unit is included in the Masinloc facilities to be sold as announced in December. The sale is expected to close in the first half of 2018.

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

- Operating performance of the facility
- Demand from contracted customers
- Whole sale electricity price in the market

Vietnam

Regulatory Framework and Market Structure — The Ministry of Industry and Trade 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 Petro Vietnam.

The Vietnam power market is divided into three regions (North, Central and South), with total installed capacity of approximately 45 GW. The fuel mix in Vietnam is composed primarily of hydropower at 35% and coal at 37%. EVN, the national utility, owns 57% of installed generation capacity.

The government is in the process of realigning EVN-owned companies into three different independent operations in order to create a competitive power market. A competitive electricity market has already been established. A pilot competitive wholesale electricity market has been developed, and will be implemented over the next five years. The retail market will undergo similar reforms after 2022. BOT power plants will not participate in the power market; alternatively the single buyer will bid the tariff on the power pool on their behalf.

Business Description — Mong Duong II is a 1,240 MW gross coal-fired plant located in Quang Ninh Province of Vietnam and was constructed under a BOT service concession agreement expiring in 2040. This is the first and largest 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.

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

Financial Data by Country

See the table with our consolidated operations for each of the three years ended December 31, 2017, 2016 and 2015, and property, plant and equipment as of December 31, 2017 and 2016, by country, in Note 15 — *Segment and Geographic Information* included in Item 8.— *Financial Statements and Supplementary Data* of this Form 10-K for further information.

Environmental and Land-Use Regulations

The Company faces certain risks and uncertainties related to numerous environmental laws and regulations, including existing and potential GHG legislation or regulations, and actual or potential laws and regulations pertaining to water discharges, waste management (including disposal of coal combustion residuals), and certain air emissions, such as SO_2, NO_X, PM, 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 businesses are subject to stringent environmental laws and regulations; Our businesses are subject to enforcement initiatives from environmental regulatory agencies;* and *Regulators, politicians, non-governmental organizations and other private parties have expressed concern about greenhouse gas, or GHG, emissions and the potential risks associated with climate change and are taking actions which could have a material adverse impact on our consolidated results of operations, financial condition and cash flows* 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 also have laws and regulations relating to the siting, construction, permitting, ownership, operation, modification, repair and decommissioning of, and power sales from, electric power generation or distribution assets. In addition, international projects funded by the International Finance Corporation, the private sector lending arm of the World Bank, or many other international lenders are subject to World Bank environmental standards or similar standards, which tend to be more stringent than local country standards. The Company often has used advanced generation technologies in order to minimize environmental impacts, such as combined fluidized bed boilers and advanced gas turbines, and environmental control devices such as flue gas desulphurization for SO_2 emissions and selective catalytic reduction for NO_x emissions.

Environmental laws and regulations affecting electric power generation and distribution facilities are complex, change frequently and have become more stringent over time. The Company has incurred and will continue to incur capital costs and other expenditures to comply with these environmental laws and regulations. See Item 7.— *Management's Discussion and Analysis of Financial Condition and Results of Operations—Environmental Capital Expenditures* in this Form 10-K for more detail. 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 U.S. the CAA and various state laws and regulations regulate emissions of air pollutants, including SO_2, NO_X, PM, GHGs, mercury and other hazardous air pollutants. Certain applicable rules are discussed in further detail below.

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

On October 26, 2016, the EPA published a final rule to update the CSAPR to address the 2008 ozone NAAQS ("CSAPR Update Rule"). The CSAPR Update Rule finds that NO_x ozone season emissions in 22 states (including Indiana, Maryland, Ohio and Oklahoma) affect the ability of downwind states to attain and maintain the 2008 ozone NAAQS, and, accordingly, the EPA issued federal implementation plans that both updated existing CSAPR NO_x ozone season emission budgets for electric generating units within these states and implemented these budgets through modifications to the CSAPR NO_x ozone season allowance trading program. Implementation started in the 2017 ozone season (May-September 2017). Affected facilities began to receive fewer ozone season NO_x allowances in 2017, resulting in the need to purchase additional allowances. While the Company's 2017 CSAPR compliance costs were 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 if certain facilities will need to purchase additional allowances based on reduced allocations.

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 RMRR exclusion of the CAA. There is ongoing uncertainty, and significant litigation, regarding which projects fall within the RMRR exclusion. The EPA has pursued a coordinated compliance and enforcement strategy to address NSR compliance issues at the nation's coal-fired power plants. The strategy has included both the filing of suits against power plant owners and the issuance of 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 a NOV issued by the EPA against IPL concerning NSR and prevention of significant deterioration issues under the CAA.

In 2000, Stuart Station received an NOV from the EPA alleging that certain activities undertaken in the past are outside the scope of the RMRR exclusion. Hutchings Station also received such an NOV in 2009. Additionally, generation units partially owned by AES but operated by other utilities have received such NOVs relating to equipment repairs or replacements alleged to be outside the RMRR exclusion. The NOVs issued to AES-operated plants have not been pursued through litigation by the EPA.

If NSR requirements were 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. In connection with the imposition of any such NSR requirements on IPL, the utility would seek recovery of any operating or capital expenditures related to air pollution control technology to reduce regulated air emissions, but not fines or penalties; however, there can be no assurances that they would be successful in that regard.

Regional Haze Rule — The EPA's "Regional Haze Rule" is intended to reduce haze and protect visibility in designated federal areas, and sets guidelines for determining BART at affected plants and how to demonstrate "reasonable progress" toward eliminating man-made haze by 2064. The Regional Haze Rule required states to consider five factors when establishing BART for sources, including the availability of emission controls, the cost of the controls and the effect of reducing emission on visibility in Class I areas (including wilderness areas, national parks and similar areas). The statute requires compliance within five years after the EPA approves the relevant SIP or issues a federal implementation plan, although individual states may impose more stringent compliance schedules.

In September 2017, the EPA published a final rule affirming the continued validity of the EPA's previous determination allowing states to rely on the CSAPR to satisfy BART requirements. All of the Company's facilities that are subject to BART comply by meeting the requirements of CSAPR.

The second phase of the Regional Haze Rule begins in 2019 and states must submit regional haze plans for this second implementation period in 2021, to continue to demonstrate reasonable progress towards reducing visibility impairment in Class I areas. States may need to require additional emissions controls for visibility impairing pollutants, including on BART sources, during the second implementation period. We currently cannot predict the impact of this second implementation period, if any, on any of our Company's U.S. subsidiaries.

National Ambient Air Quality Standards ("NAAQS") — Under the CAA, the EPA sets NAAQS for six principal pollutants considered harmful to public health and the environment, including ozone, particulate matter, NO_x and SO_2, which result from coal 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 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 State Implementation Plans 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.

On September 30, 2015, IDEM published its final rule establishing reduced SO_2 limits for IPL facilities in accordance with a new one-hour standard of 75 parts per billion, for the areas in which IPL's Harding Street, Petersburg, and Eagle Valley Generating Stations operate. The compliance date for these requirements was January 1, 2017. No impact is expected for Eagle Valley or Harding Street Generating Stations because these facilities ceased coal combustion prior to the compliance date. However, improvements to the existing FGD systems at IPL’s Petersburg station were required to meet the emission limits imposed by the rule. On April 26, 2017, the IURC approved IPL’s request for NAAQS SO_2 compliance at its Petersburg generation station with 80% of qualifying costs recovered through a rate adjustment mechanism and the remainder recorded as a regulatory asset for recovery in a subsequent rate case. The approved capital cost of the NAAQS SO_2 compliance plan is approximately $29 million.

Greenhouse Gas Emissions — In January 2011, the EPA began regulating GHG emissions from certain stationary sources pursuant to two CAA programs: the Title V Operating Permit program and the preconstruction permitting program for certain new construction or major modifications, known as the PSD. Obligations relating to Title V permits include record-keeping and monitoring requirements. Sources subject to PSD can be required to implement BACT. If future modifications to our U.S.-based businesses' sources become subject to PSD for other pollutants, it may trigger GHG BACT requirements. The EPA has issued guidance on what BACT entails for the control of GHG and has now proposed NSPS for modified and reconstructed units (see below) that will serve as a floor (maximum emission rate) for future BACT requirements. Individual states must determine what controls are required for facilities within their jurisdiction on a case-by-case basis. The ultimate impact of the BACT requirements applicable to us on our operations cannot be determined at this time as our U.S.-based businesses will not be required to implement BACT until one of them constructs a new major source or makes a major modification of an existing major source. However, the cost of compliance could be material.

On October 23, 2015, the EPA's rule establishing NSPS for new electric generating units became effective. The NSPS establish CO_2 emissions standards of 1400 lbs/MWh for newly constructed coal-fueled electric generating plants, which reflects the partial capture and storage of CO_2 emissions from the plants. The NSPS for large, newly constructed natural gas combined cycle facilities is 1,000 lbs/MWh. These standards apply to any electric generating unit with construction commencing after January 8, 2014. The EPA also promulgated NSPS applicable to modified and reconstructed electric generating units, which will serve as a floor for future BACT determinations for such units. The NSPS applicable to modified and reconstructed coal-fired units will be 1,800 lbs CO_2/MWh for sources with heat input greater than 2,000 MMBtu per hour. For smaller sources, below 2,000 MMBtu per hour, the standard is 2,000 lbs CO_2/MWh. The NSPS could have an impact on the Company's plans to construct and/or modify or reconstruct electric generating units in some locations.

On December 22, 2015, the EPA's final CO_2 emission rules for existing power plants under Clean Air Act Section 111(d) (called the CPP) also became effective. The CPP provides for interim emissions performance rates that must be achieved beginning in 2022 and final emissions performance rates that must be achieved starting in 2030. Under the CPP, states are required to meet state-wide emission rate standards or equivalent mass-based standards, with the goal being a 32% reduction in total U.S. power sector emissions from 2005 levels by 2030. The CPP requires states to submit, by 2016, implementation plans to meet the standards or a request for an extension to 2018. If a state fails to develop and submit an approvable implementation plan, the EPA will finalize a federal plan for that state. The full impact of the CPP would depend on the following:

- whether and how the states in which the Company's U.S. businesses operate respond to the CPP;
- whether the states adopt an emissions trading regime and, if so, which trading regime;
- how other states respond to the CPP, which will affect the size and robustness of any emissions trading market; and
- how other companies may respond in the face of increased carbon costs.

Several states and industry groups challenged the NSPS for CO_2 in the D.C. Circuit. Pursuant to a court order issued in August 2017, the litigation is being held in indefinite abeyance pending further court order.

In addition, several states and industry groups filed petitions in the D.C. Circuit challenging the CPP and requested a stay of the rule while the challenge was considered. The D.C. Circuit denied the stay and granted requests to consider the challenges on an expedited basis. On February 9, 2016, the U.S. Supreme Court issued orders staying implementation of the CPP pending resolution of challenges to the rule. On March 28, 2017, the EPA filed a motion in the D.C. Circuit to hold the challenges to both the CPP and the GHG NSPS in abeyance in light of an Executive Order signed the same day. On April 28, 2017, the D.C. Circuit issued orders holding the challenges to both rules in abeyance for 60 days, with subsequent extensions granted by the court. The most recent extension of the CPP litigation was set to expire in January 2018 but, on January 10, 2018, the EPA filed a status report requesting that the court continue to hold the case in abeyance pending the conclusion of further rulemaking on the CPP. On October 16, 2017, the EPA published in the Federal Register a proposed rule that would rescind the CPP. On December 28, 2017, the EPA published an Advance Notice of Proposed Rulemaking to solicit comments as EPA considers a potential rule to establish emission guidelines to replace the CPP and limit GHG emissions from existing electric generating units under Section 111(d) of the CAA. Some states and environmental groups have opposed EPA’s most recent request to continue to hold the CPP appeals in abeyance and the D.C. Circuit has not yet acted upon EPA’s request.

By order of the U.S. Supreme Court, the CPP has been stayed pending resolution of the challenges to the rule. Due to the future uncertainty of the CPP, we cannot at this time determine the impact on our operations or consolidated financial results, but we believe the cost to comply with the CPP, should it be upheld and implemented in its current or a substantially similar form, could be material. The GHG NSPS 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.

The Company will likely not know the answers to the above questions regarding the CPP until later in 2018 or potentially 2019. As the first compliance period would not end until 2025, and because we cannot predict whether the CPP will survive the legal challenges or be repealed or replaced through rulemaking, it is too soon to determine the CPP's potential impact on our business, operations or financial condition, but any such impact could be material.

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 that seeks to protect fish and other aquatic organisms by requiring existing steam electric generating facilities to utilize the BTA for cooling water intake structures. On August 15, 2014, the EPA published its final standards to protect fish and other aquatic organisms drawn into cooling water systems at large power plants and other industrial facilities. These standards require subject facilities that utilize at least 25% of the withdrawn water exclusively for cooling purposes and have a design intake flow of greater than two million gallons per day to choose among seven BTA options to reduce fish impingement. In addition, facilities that withdraw at least 125 million gallons per day for cooling purposes 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. This decision-making process would include public input as part of permit renewal or permit modification. It is possible this process 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 that achieves one of two alternatives under national BTA standards for entrainment. It is not yet possible to predict the total impacts of this recent 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.

AES Southland's current plan is to comply with the California State Water Resources Board's ("SWRCB") *Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* ("OTC Policy") by shutting down and permanently retiring all existing generating units at AES Alamitos, AES Huntington Beach and AES Redondo Beach that utilize OTC by December 31, 2020, the compliance date included in the OTC Policy. New air-cooled combined cycle gas turbine generators and battery energy storage systems will be constructed at the AES Alamitos and AES Huntington Beach generating stations, and there is currently no plan to replace the OTC generating units at the AES Redondo Beach generating station. The execution of the implementation plan for compliance with the SWRCB's OTC Policy is entirely dependent on the Company's ability to execute on long-term power purchase agreements to support project financing of the replacement generating units at AES Alamitos and AES Huntington Beach. The SWRCB is currently reviewing the implementation plan and latest information on OTC generating unit retirement dates and new generation availability to evaluate the impact on electrical system reliability, which could result in the extension of OTC compliance dates for specific units. The Company’s California subsidiaries have signed 20-year term power purchase agreements with Southern California

Edison for the new generating capacity which have been approved by the California Public Utilities Commission. Construction of new generating capacity began in June 2017 at AES Huntington Beach and July 2017 at AES Alamitos. Construction at both sites is on schedule and will require the following existing OTC units to retire earlier than December 31, 2020 to provide interconnection capacity and/or emissions credits prior to startup of the new generating units:

- Redondo Beach Unit 7 - September 30, 2019
- Huntington Beach Unit 1 - December 31, 2019
- Alamitos Units 1, 2, and 6 - December 31, 2019

The remaining AES OTC generating units in California will be shutdown and permanently retired by December 31, 2020.

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. Challenges to the federal EPA's rule have been filed and consolidated in the U.S. Court of Appeals for the Second Circuit, although implementation of the rule has not been stayed while the challenges proceed. The Company anticipates once-through cooling and CWA Section 316(b) compliance regulations and costs would have a material impact on our consolidated financial condition or results of operations.

Water Discharges — On June 29, 2015, the EPA and the U.S. Army Corps of Engineers published a final rule defining federal jurisdiction over waters of the U.S. This rule, which became effective on August 28, 2015, may expand or otherwise change the number and types of waters or features subject to federal permitting. On October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order to temporarily stay the "Waters of the U.S." rule nationwide while that court determined whether it had authority to hear the challenges to the rule. The order was in response to challenges brought by 18 states and followed an August 2015 court decision in the U.S. District Court of North Dakota to stay the rule in 13 other states. On January 22, 2018, the U.S. Supreme Court decided that challenges to the rule must be reviewed in U.S. district courts and remanded the case to the U.S. Court of Appeals for the Sixth Circuit with instructions to dismiss the case for lack of jurisdiction. That action would lift the nationwide stay of the rule, leaving the stay in place only for those 13 states addressed in the order issued by the U.S. District Court for the District of North Dakota. On January 31, 2018, the EPA and the U.S. Army Corps of Engineers announced a rule that will delay the effective date of the "Waters of the U.S." rule by two years from the date the rule is published in the Federal Register. On June 27, 2017, the EPA proposed a rule that would rescind the “Waters of the U.S.” rule and re-codify the definition of “Waters of the United States” that existed prior to the 2015 rule. We cannot predict the outcome of the judicial challenges to the rule or the regulatory process to rescind the rule, but if the “Waters of the U.S.” rule is ultimately implemented in its current or substantially similar form and survives the legal challenges, it could have a material impact on our business, financial condition or results of operations.

Certain of the Company's U.S.-based businesses are subject to National Pollutant Discharge Elimination System permits that regulate specific industrial waste water and storm water discharges to the waters of the U.S. under the CWA. On January 7, 2013, the Ohio Environmental Protection Agency issued an NPDES permit for J.M. Stuart Station, which included a compliance schedule for performing a study to justify an alternate thermal limitation or take undefined measures to meet certain temperature limits. On February 1, 2013, DPL appealed various aspects of the final permit. As a result of DPL’s decision to retire Stuart generating station, we do not expect a material impact.

On August 28, 2012, the IDEM issued NPDES permits to the IPL Petersburg, Harding Street and Eagle Valley generating stations, which became effective in October 2012. These permits set new water quality-based effluent discharge limits for the Harding Street and Petersburg facilities, as well as monitoring and other requirements designed to protect aquatic life, with full compliance required by October 2015. The extended compliance deadline was September 29, 2017 for IPL's Harding Street and Petersburg facilities through agreed orders with IDEM. The deadline for Petersburg to commission a portion of the treatment system was subsequently extended to April 11, 2018.

On November 3, 2015, the EPA published its final ELG rule to reduce toxic pollutants discharged into waters of the U.S. by power plants. 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 de-sulfurization wastewater. The required compliance time lines for existing sources was to be established between November 1, 2018 and December 31, 2023. On September 18, 2017, the EPA published a final rule delaying certain compliance dates of the ELG rule for two years while it administratively reconsiders the rule. IPL has installed a dry bottom ash handling system in response to the CCR rule described below in advance of the ELG compliance date. As a result of the decision to retire Stuart and Killen generating stations, we do not expect the ELG rule to have a material impact on these two stations. While we are still evaluating the effects of the rule on our other U.S. businesses, we anticipate that the implementation of its current requirements could have a material adverse effect on our results of operations, financial condition and cash flows, and a postponement or reconsideration of the rule that leads to less stringent requirements would likely offset some or all of the adverse effects of the rule.

Selenium Rule — In June 2016, the EPA published the final national chronic aquatic life criterion for the pollutant Selenium in fresh water. NPDES permits may be updated to include Selenium water quality based effluent limits based on a site specific evaluation process which includes determining if there is a reasonable potential to exceed the revised final Selenium water quality standards for the specific receiving water body utilizing actual and/or project discharge information for the generating facilities. As a result, 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. IPL would seek recovery of these capital expenditures; however, there is no guarantee it would be successful in this regard.

Waste Management — In the course of operations, the Company's facilities generate solid and liquid waste materials requiring eventual disposal or processing. With the exception of coal combustion residuals ("CCR"), the wastes are not usually physically disposed of on our property, but are shipped off site for final disposal, treatment or recycling. CCR, which consists of bottom ash, fly ash and air pollution control wastes, is disposed of at some of our coal-fired power generation plant sites using engineered, permitted landfills. Waste materials generated at our electric power and distribution facilities may include asbestos, CCR, oil, scrap metal, rubbish, small quantities of industrial hazardous wastes such as spent solvents, tree and land clearing wastes and polychlorinated biphenyl contaminated liquids and solids. The Company endeavors to ensure that all of its solid and liquid wastes are disposed of in accordance with applicable national, regional, state and local regulations. On October 19, 2015, an EPA rule regulating CCR under the Resource Conservation and Recovery Act as nonhazardous solid waste became effective. The rule established nationally applicable minimum criteria for the disposal of CCR in new and currently operating landfills and surface impoundments, and may impose closure and/or corrective action requirements for existing CCR landfills and impoundments under certain specified conditions. The primary enforcement mechanisms under this regulation would be actions commenced by the states and private lawsuits. On December 16, 2016, President Obama signed into law the Water Infrastructure Improvements for the Nation Act ("WIN Act"), which 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 September 13, 2017, the EPA indicated that it would reconsider certain provisions of the CCR Rule in response to two petitions it received to reconsider the final rule. On November 7, 2017, the EPA requested that legal challenges be held in abeyance and certain provisions of the rule be remanded without vacatur. It is too early to determine whether the results of the groundwater monitoring data or the outcome of CCR litigation or a potential CCR Remand Rule may have a material impact on our business, financial condition or results of operations.

The existing ash ponds at IPL's Petersburg Station do not meet certain structural stability requirements set forth in the CCR rule. IDEM has extended IPL's deadline to comply with the requirements or cease use of the ash ponds to April 11, 2018.

Comprehensive Environmental Response, Compensation and Liability Act of 1980 — This act, also know as "Superfund," may be the source of claims against certain of the Company's U.S. subsidiaries from time to time. There is ongoing litigation at a site known as the South Dayton Landfill where a group of companies already recognized as potentially responsible parties have sued DP&L and other unrelated entities seeking a contribution toward the costs of assessment and remediation. DP&L is actively opposing such claims. In 2003, DP&L received notice that the EPA considers DP&L to be a potentially responsible party at the Tremont City landfill Superfund site. The EPA has taken no further action with respect to DP&L since 2003 regarding the Tremont City landfill. The Company is unable to determine whether there will be any liability, or the size of any liability that may ultimately be assessed against DP&L at these two sites, but any such liability could be material to DP&L.

Unit Retirement and Replacement Generation — In addition to the five oil-fired peaking units IPL retired in the second quarter of 2013, the four coal-fired units at Eagle Valley were retired in April 2016. To replace this generation, IPL received approval from the IURC in May 2014 to build a 644 to 685 MW CCGT at its Eagle Valley Station site in Indiana and refuel its Harding Street Station Units 5 and 6 from coal to natural gas (approximately 100 MW net capacity each) with a total budget of $655 million. The current estimated cost of these projects is $655 million. IPL was granted authority to accrue post in-service allowance for debt and equity funds used during construction, and to defer the recognition of depreciation expense of the CCGT and refueling project. The costs to build and operate the CCGT and the refueling project, other than fuel costs, will not be recoverable by IPL through rates until the conclusion of a base rate case proceeding with the IURC after construction is completed. The CCGT is expected to be completed in the first half of 2018, and the refueling project was completed in December 2015.

For a discussion of the retirement of AES Southland's OTC generating units due to U.S. cooling water intake regulations, please see — *Cooling Water Intake,* above.

International Environmental Regulations

For a discussion of the material environmental regulations applicable to the Company's businesses located outside of the U.S., see *Environmental Regulation* under the discussion of the various countries in which the Company's subsidiaries operate in *Business—Our Organization and Segments,* above.

Customers

We sell to a wide variety of customers. No individual customer accounted for 10% or more of our 2017 total revenue. In our generation business, we own and/or operate power plants to generate and sell power to wholesale customers such as utilities and other intermediaries. Our utilities sell to end-user customers in the residential, commercial, industrial and governmental sectors in a defined service area.

Executive Officers

The following individuals are our executive officers:

***Bernerd Da Santos**,* 54 years old, was appointed Chief Operating Officer and Executive Vice President in December 2017. Previously, Mr. Da Santos held several positions at the Company, including Chief Operating Officer and Senior Vice President (2014 - 2017), Chief Financial Officer, Global Finance Operations (2012-2014), Chief Financial Officer of Global Utilities (2011-2012), Chief Financial Officer of Latin America and Africa (2009-2011), Chief Financial Officer of Latin America (2007-2009), Managing Director of Finance for Latin America (2005-2007) and VP and Controller of EDC (Venezuela). Prior to joining AES in 2000, Mr. Da Santos held a number of financial leadership positions at EDC. Mr. Da Santos is the chairman of AES Gener in Chile and a member of the Board of Directors of Companhia Brasiliana de Energia, AES Tietê, Companhia de Alumbrado Electrico de San Salvador ("CAESS"), Empresa Electrica de Oriente ("EEO"), Companhia de Alumbrado Electrico de Santa Ana, and Indianapolis Power & Light. 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.

Paul L. Freedman, 47 years old, has been Senior Vice President and General Counsel since February 2018. Prior to assuming his current position, Mr. Freedman served as Chief of Staff to the CEO from April 2016 to February 2018, Assistant General Counsel from 2014 to 2016, General Counsel, North America Generation, from 2011 to 2014, Senior Corporate Counsel from 2010-2011 and Counsel 2007 to 2010. Mr. Freedman is a member of the boards of IPALCO, AES U.S. Investments, DP&L and Fluence. He is also an alternate Director at AES Gener. 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, LLP and Freshfields. Mr. Freedman received a B.A. from Columbia University and a J.D. from the Georgetown University Law Center.

***Andrés R. Gluski**,* 60 years old, has been President, CEO and a member of our Board of Directors since September 2011 and is Chairman of the Strategy and Investment Committee of the Board. Prior to assuming his current position, Mr. Gluski served as EVP and Chief Operating Officer ("COO") of the Company since March 2007. Prior to becoming the COO of AES, Mr. Gluski was EVP and the Regional President of Latin America from 2006 to 2007. Mr. Gluski was Senior Vice President ("SVP") for the Caribbean and Central America from 2003 to 2006, CEO of La Electricidad de Caracas ("EDC") from 2002 to 2003 and CEO of AES Gener (Chile) in 2001. Prior to joining AES in 2000, Mr. Gluski was EVP and Chief Financial Officer ("CFO") of EDC, EVP of Banco de Venezuela (Grupo Santander), Vice President ("VP") for Santander Investment, and EVP and CFO of CANTV (subsidiary of GTE). Mr. Gluski has also worked with the International Monetary Fund in the Treasury and Latin American Departments and served as Director General of the Ministry of Finance of Venezuela. From 2013-2016, Mr. Gluski served on President Obama's Export Council. Mr. Gluski is a member of the Board of Waste Management and AES Gener in Chile. Mr. Gluski is also Chairman of the Americas Society/Council of the Americas, and Director of the Edison Electric Institute. 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, 42 years old, is Chief Human Resources Officer and Senior Vice President, Global Human Resources and Internal Communications since 2015. Prior to assuming her current position, Ms. Mendoza was the

Vice President of Human Resources, Global Utilities from 2011 to 2012 and 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. In 2015, Ms. Mendoza was appointed a member of the Boards of AES Chivor S.A. and DP&L, and sits on AES' compensation and benefits committees. She is also currently serving as co-chair of Evanta Global HR, and is part of its governing body in Washington, D.C. 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.

Thomas M. O'Flynn, 57 years old, has served as EVP and CFO of the Company since September 2012. Previously, Mr. O'Flynn served as Senior Advisor to the Private Equity Group of Blackstone, an investment and advisory group and held this position from 2010 to 2012. During this period, Mr. O'Flynn also served as COO and CFO of Transmission Developers, Inc., a Blackstone-controlled company that develops innovative power transmission projects in an environmentally responsible manner. From 2001 to 2009, he served as the CFO of PSEG, a New Jersey-based merchant power and utility company. He also served as President of PSEG Energy Holdings from 2007 to 2009. From 1986 to 2001, Mr. O'Flynn was in the Global Power and Utility Group of Morgan Stanley. He served as a Managing Director for his last five years and as head of the North American Power Group from 2000 to 2001. He was responsible for senior client relationships and led a number of large merger, financing, restructuring and advisory transactions. Mr. O'Flynn is the chairman of IPALCO, AES U.S. Investments and FTP Power, LLC. Mr. O'Flynn previously served as a member of the Boards of DP&L and its parent company, DPL, Inc. from February 2013 through February 2015 and served on the Board of Silver Ridge Power, a joint venture between AES and Riverstone Holdings LLC from September 2012 through July 2014. He is also currently on the Board of Directors of the New Jersey Performing Arts Center and was the inaugural Chairman of the Institute for Sustainability and Energy at Northwestern University, of which he is still an active Board member. Mr. O'Flynn has a BA in Economics from Northwestern University and an MBA in Finance from the University of Chicago.

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. You may also read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. 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 19, 2017.

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, including those discussed in Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations 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.*

We routinely encounter and address risks, some of which may cause our future results to be different, sometimes materially different, than we presently anticipate. The categories of risk we have identified in Item 1A.—*Risk Factors* of this Form 10-K include the following:

- risks related to our high level of indebtedness;
- risks associated with our ability to raise needed capital;
- external risks associated with revenue and earnings volatility;
- risks associated with our operations; and
- risks associated with governmental regulation and laws.

These risk factors should be read in conjunction with Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations*, and the Consolidated Financial Statements and related notes included elsewhere in this report.

Risks Related to our High Level of Indebtedness

We have a significant amount of debt, a large percentage of which is secured, which could adversely affect our business and the ability to fulfill our obligations.

As of December 31, 2017, we had approximately $20 billion of outstanding indebtedness on a consolidated basis. All outstanding borrowings, if any, under The AES Corporation's senior secured credit facility and secured term loan are secured by certain of our assets, including the pledge of capital stock of many of The AES Corporation's directly held subsidiaries. Most of the debt of The AES Corporation's subsidiaries is secured by substantially all of the assets of those subsidiaries. Since we have such a high level of debt, a substantial portion of cash flow from operations must be used to make payments on this 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 high level of indebtedness and related security could have other important consequences to us and our investors, including:

- making it more difficult to satisfy debt service and other obligations at the holding company and/or individual subsidiaries;
- increasing our vulnerability to general adverse industry and economic conditions, including but not limited to adverse changes in foreign exchange rates and commodity prices;
- reducing the availability of 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 the financial and other restrictive covenants relating to such indebtedness, among other things, our ability to borrow additional funds as needed or take advantage of business opportunities as they arise, 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. To the extent we become more leveraged, the risks described above would increase. Further, our actual cash requirements in the future may be greater than expected. Accordingly, our cash flows may not be sufficient to repay at maturity all of the outstanding debt as it becomes due and, in that event, we may not be able to borrow money, sell assets, raise equity or otherwise raise funds on acceptable terms or at all to refinance our debt as it becomes due. See Note 10.—*Debt* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for a schedule of our debt maturities.

The AES Corporation is a holding company and its ability to make payments on its outstanding indebtedness, including its public debt securities, is dependent upon the receipt of funds from its subsidiaries by way of dividends, fees, interest, loans or otherwise.

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.

However, our subsidiaries face various restrictions in their ability to distribute cash to The AES Corporation. 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 to The AES Corporation, if at all. Business performance and local accounting and tax rules may also limit dividend distributions. Subsidiaries in foreign countries may also be prevented from distributing funds to The AES Corporation as a result of foreign governments restricting the repatriation of funds or the conversion of currencies.

The AES Corporation's subsidiaries are separate and distinct legal entities and, unless they have expressly guaranteed any of 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.

Even though The AES Corporation is a holding company, existing and potential future defaults by subsidiaries or affiliates could adversely affect The AES Corporation.

We attempt to finance our domestic and foreign projects primarily under loan agreements and related documents which, except as noted below, require 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. This type of financing is usually referred to as non-recourse debt or "non-recourse financing." In some non-recourse financings, The AES Corporation has explicitly agreed to undertake certain limited obligations and contingent liabilities, most of which by their terms will only be effective or will be terminated upon the occurrence of future events. These obligations and liabilities take the form of guarantees, indemnities, letters of credit, letter of credit reimbursement agreements and agreements to pay, in certain circumstances, the project lenders or other parties.

As of December 31, 2017, we had approximately $20 billion of outstanding indebtedness on a consolidated basis, of which approximately $4.6 billion was recourse debt of The AES Corporation and approximately $15.3 billion was non-recourse debt. In addition, we have outstanding guarantees, indemnities, letters of credit, and other credit support commitments which are further described in this Form 10-K in Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Parent Company Liquidity*.

Some of our subsidiaries are currently 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 $1 billion as of December 31, 2017. While the lenders under our non-recourse financings generally do not have direct recourse to The AES Corporation (other than to the extent of any credit support given by The AES Corporation), defaults thereunder can still have important consequences for The AES Corporation, including, without limitation:

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

None of the projects that are currently in default are owned by subsidiaries that individually or in the aggregate meet the applicable standard of materiality in The AES Corporation's senior secured credit facility or other debt agreements in order for such defaults 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 matters that affect our financial position and results of operations, it is possible that 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 the indebtedness under The AES Corporation's senior secured credit facility or other indebtedness of The AES Corporation.

Risks Associated with our Ability to Raise Needed Capital

The AES Corporation, or the Parent Company, has significant cash requirements and limited sources of liquidity.

The AES Corporation requires cash primarily to fund:

- principal repayments of debt;
- interest;
- acquisitions;
- construction and other project commitments;
- other equity commitments, including business development investments;
- equity repurchases and/or cash dividends on our common stock;
- taxes; and
- Parent Company overhead costs.

The AES Corporation's principal sources of liquidity are:

- dividends and other distributions from its subsidiaries;
- proceeds from debt and equity financings at the Parent Company level; and
- proceeds from asset sales.

For a more detailed discussion of The AES Corporation's cash requirements and sources of liquidity, please see Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity* in this Form 10-K.

While we believe that these sources will be adequate to meet our obligations at the Parent Company level 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 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. Any number of assumptions could prove to be incorrect, and, therefore 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 at maturity the entire principal outstanding under our credit facility, term loan, and our debt securities and we may have to refinance such obligations. There can be no assurance that we will be successful in obtaining such refinancing on terms acceptable to us or at all and any of these events could have a material effect on us.

Our ability to grow our business could be materially adversely affected if we were unable to raise capital on favorable terms.

From time to time, we rely on access to 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 financial condition, performance and prospects of The AES Corporation in general and/or that of any subsidiary requiring the financing as well as companies in our industry or similar financial circumstances; and
- changes in tax and securities laws which are conducive to raising capital.

Should future access to capital not be available to us, we may have to sell assets or decide not to build new plants, or expand or improve existing facilities, either of which would affect our future growth, results of operations or financial condition.

A downgrade in the credit ratings of The AES Corporation or its subsidiaries could adversely affect our ability to access the capital markets which could increase our interest costs or adversely affect our liquidity and cash flow.

If any of the credit ratings of The AES Corporation or its subsidiaries were to be downgraded, our ability to raise capital on favorable terms could be impaired and our borrowing costs could increase. Furthermore, depending on The AES Corporation's credit ratings and the trading prices of its equity and debt securities, counterparties may no longer be as willing to accept general unsecured commitments by The AES Corporation to provide credit support. Accordingly, with respect to both new and existing commitments, The AES Corporation 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. There can be no assurance that such counterparties will accept such guarantees or that AES could arrange such further assurances in the future. In addition, to the extent The AES Corporation is required and able to provide letters of credit or other collateral to such counterparties, it will limit the amount of credit available to The AES Corporation to meet its other liquidity needs.

We may not be able to raise sufficient capital to fund developing projects in certain less developed economies which could change or in some cases adversely affect our growth strategy.

Part of our strategy is to grow our business by developing businesses in less developed economies where the return on our investment may be greater than projects in more developed economies. Commercial lending institutions sometimes refuse to provide non-recourse project financing in certain less developed economies, and in these situations we have sought and will continue to seek direct or indirect (through credit support or guarantees) project financing from a limited number of multilateral or bilateral international financial institutions or agencies. As a precondition to making such project financing available, the lending institutions may also require governmental guarantees for certain project and sovereign related risks. There can be no assurance, however, that project financing from the international financial agencies or that governmental guarantees will be available when needed, and if they are not, we may have to abandon the project or invest more of our own funds which may not be in line with our investment objectives and would leave less funds for other projects.

External Risks Associated with Revenue and Earnings Volatility

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, which could have a material adverse effect on our financial performance.

Some of our businesses sell electricity in the spot markets in cases where they operate at levels in excess of their power sales agreements or retail load obligations. 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;
- seasonality;
- hydrology and other weather conditions;
- illiquid markets;
- transmission or transportation constraints or inefficiencies;
- renewables source contribution to the supply stack;
- increased adoption of distributed generation;
- energy efficiency and demand side resources;
- available supplies of natural gas, crude oil and refined products, and coal;
- generating unit performance;
- natural disasters, terrorism, wars, embargoes, and other catastrophic events;
- energy, market and environmental regulation, legislation and policies;
- general economic conditions in areas where we operate which impact energy consumption; and
- bidding behavior and market bidding rules.

Our financial position and results of operations may fluctuate significantly due to fluctuations in currency exchange rates experienced at our foreign operations.

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 many 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 subsidiaries outside the U.S. report could cause significant fluctuations in our results. In addition, while our expenses with respect to foreign operations 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. Our financial position and results of operations could be affected by fluctuations in the value of a number of currencies.

Wholesale Power Prices are declining in many markets and this could have a material adverse effect on our operations and opportunities for future growth.

The wholesale prices offered for electricity have declined significantly in recent years in many markets in which the Company has businesses. This price decline is due to a variety of factors, including the increased penetration of renewable generation resources, cheap natural gas and demand side management. The levelized cost of electricity from new solar and wind generation sources has dropped substantially in recent years as solar panel costs have declined and wind turbine costs have declined, while wind capacity factors have increased. These renewable resources have no fuel costs and very low operational costs. In many instances energy from these facilities are bid into the wholesale spot market at a price of zero or close to zero during certain times of the day, driving down the clearing price for all generators selling power in the relevant spot market. Also, in many markets new power purchase agreements have been awarded for renewable generation at prices significantly lower than the prices being awarded just a few years ago.

This trend of declining wholesale prices could continue and could have a material adverse impact on the financial performance of our existing generation assets to the extent they currently sell power into the spot market or will seek to sell power into the spot market once their power purchase agreements expire. The trend of declining prices can also make it more difficult for us to obtain attractive prices under new long-term power purchase agreements for any new generation facilities we may seek to develop. As a result, the trend can have an adverse impact on our opportunities for new investments.

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 targeted underlying exposure. 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.

For our businesses with PPA pricing that does not perfectly 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.

Supplier and/or customer concentration may expose the Company 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.

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. We may not be able to enter into replacement agreements on terms as favorable as our existing agreements, or at all. If we were unable to enter into replacement PPAs, these businesses may have to sell power at market prices. A breach by a counterparty of a PPA or other agreement could also result in the breach of other agreements, including, without limitation, the debt documents of the affected business.

The failure of any supplier or customer to fulfill its contractual obligations to The AES Corporation or our subsidiaries could have a material adverse effect on our financial results. Consequently, the financial performance of our facilities is dependent on the credit quality of, and continued performance by, suppliers and customers.

The market pricing of our common stock may be volatile in future periods.

The market price for our common stock could fluctuate substantially in the future. Stock price movements on a quarter-by-quarter basis for the past two years are presented in Item 5.—*Market For Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*—*Market Information* of this Form 10-K. Factors that could affect the price of our common stock in the future include general conditions in our industry, in the power markets in which we participate and in the world, including environmental and economic developments, over which we have no control, as well as developments specific to us, including risks that could result in revenue and earnings volatility as well as other risk factors described in Item 1A.—*Risk Factors* and those matters described in Item 7.—*Management's Discussion and Analysis of Financial Conditions and Results of Operations*.

Risks Associated with our Operations

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

A significant amount of our revenue is generated outside the U.S. and a significant portion of our international operations is conducted in developing countries. Part of our growth strategy is to expand our business in certain developing countries in which AES has an existing presence as such countries may have higher growth rates and offer greater opportunities to expand from our platforms, with potentially higher returns than in some more developed countries. 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;
- 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 or fiscal policies;
- high inflation and monetary fluctuations;
- restrictions on imports of 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;
- risks relating to the failure to comply with the U.S. Foreign Corrupt Practices Act, United Kingdom Bribery Act or other anti-bribery laws applicable to our operations;
- difficulties in hiring, training and retaining qualified personnel, particularly finance and accounting personnel with GAAP expertise;
- unwillingness of governments and their agencies, similar organizations or other counterparties to honor their contracts;
- 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;
- difficulties in enforcing our contractual rights or enforcing judgments or obtaining a favorable result in local jurisdictions; and
- potentially adverse tax consequences of operating in multiple jurisdictions.

Any of these factors, by itself or in combination with others, could materially and adversely affect our business, results of operations and financial condition. Our operations may experience volatility in revenues and operating margin 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 and currency devaluations being experienced in many of these countries. This volatility reduces the predictability and enhances the uncertainty associated with cash flows from these businesses. A number of our businesses are facing challenges associated with regulatory changes.

The operation of power generation, distribution and transmission facilities involves significant risks that could adversely affect our financial results. We and/or our subsidiaries may not have adequate risk mitigation and/or insurance coverage for liabilities.

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, explosions, terrorist acts, 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. This could have a material adverse effect on our businesses' results of operations, financial condition and prospects.

In addition, a portion of our generation facilities were constructed many years ago. Older generating equipment may require significant capital expenditures for maintenance. The equipment at our plants, whether old or new, is also likely to require 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 may impact the ability of our plants to perform and could, therefore, have a material impact on our business and results of operations. 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.

As a result of the above risks and other potential hazards associated with the power generation, distribution and transmission industries, we may from time to time become exposed to significant liabilities for which we may not have adequate risk mitigation and/or insurance coverage. 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 the existence of operational procedures, preventative maintenance plans and specific programs supported by quality control systems which reduce, but do not eliminate, the possibility of the occurrence and impact of these risks.

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. We maintain an amount of insurance protection that we believe is customary, but there can be no assurance that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. A claim for which we are not fully insured or insured at all could hurt our financial results and materially harm our financial condition. Further, due to the cyclical nature of the insurance markets, we cannot provide assurance that insurance coverage will continue to be available on terms similar to those presently available to us or at all. Any losses not covered by insurance could have a material adverse effect on our financial condition, results of operations or cash flows.

Our businesses' insurance does not cover every potential risk associated with its operations. Adequate coverage at reasonable rates is not always obtainable. In addition, insurance may not fully cover the liability or the consequences of any business interruptions such as equipment failure or labor dispute. The occurrence of a significant adverse event not fully or partially covered by insurance could have a material adverse effect on the Company's business, results or operations, financial condition and prospects.

Any of the above risks could have a material adverse effect on our business and results of operations.

We may not be able to attract and retain skilled people, which could have a material adverse effect on our operations.

Our operating success and ability to carry out growth initiatives depends in part on our ability to retain executives and to attract and retain additional qualified personnel who have experience in our industry and in operating a company of our size and complexity, including people in our foreign businesses. The inability to attract and retain qualified personnel could have a material adverse effect on our business, because of the difficulty of promptly finding qualified replacements. For example, we routinely are required to assess the financial impacts of complicated business transactions which occur on a worldwide basis. These assessments are dependent on hiring personnel on a worldwide basis with sufficient expertise in U.S. GAAP to timely and accurately comply with U.S. reporting obligations. An inability to maintain adequate internal accounting and managerial controls and hire and retain qualified personnel could have an adverse effect on our financial and tax reporting.

We have contractual obligations to certain customers to provide full requirements service, which makes it difficult to predict and plan for load requirements and may result in increased operating costs to certain of our businesses.

We have contractual obligations to certain customers to supply power to satisfy all or a portion of their energy requirements. The uncertainty regarding the amount of power that our power generation and distribution facilities must be prepared to supply to customers may increase our operating costs. A significant under- or over-estimation of load requirements could result in our facilities not having enough or having too much power to cover their obligations, in which case we would be required to buy or sell power from or to third parties at prevailing market prices. Those prices may not be favorable and thus could increase our operating costs.

We may not be able to enter into long-term contracts, which reduce volatility in our results of operations.

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 25 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 in part 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 failed to maintain, an investment-grade credit rating, and our generation business cannot always obtain government guarantees and if they do, the government does not always have an investment grade credit rating. We have also sought to reduce our credit risk by locating 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 to mitigate this risk will be successful.

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, or are anticipated to cause, price pressure in certain power markets where we sell or intend to sell power. These competitive factors could have a material adverse effect on us.

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

Certain of our subsidiaries have defined benefit pension plans covering substantially all of their respective employees. Of the thirty one such defined benefit plans, five are at U.S. subsidiaries and the remaining plans are at foreign 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 wrong, resulting in a shortfall of pension plan assets compared to pension obligations under the pension plan. The Company periodically evaluates the value of the pension plan assets to ensure that they will be sufficient to fund the respective pension obligations. The Company's exposure to market volatility is mitigated to some extent due to the fact that the asset allocations in our largest plans include a significant weighting of investments in fixed income securities that are less volatile than investments in equity securities. Future 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 an increase in pension expense and future funding requirements, which may be material. Our subsidiaries who participate in these plans are responsible for satisfying the funding requirements required by law in their respective jurisdiction for any shortfall of pension plan assets compared to pension obligations under the pension plan. This may necessitate additional cash contributions to the pension plans that could adversely affect the Parent Company and our subsidiaries' liquidity.
For additional information regarding the funding position of the Company's pension plans, see Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Pension and Other Postretirement Plans* and Note 13.—*Benefit Plans* included in Item 8.—*Financial Statements and Supplementary Data* included in this Form 10-K.

Our business is subject to substantial development uncertainties.

Certain of our subsidiaries and affiliates are in various stages of developing and constructing power plants, some but not all of which have signed long-term contracts or made similar arrangements for the sale of electricity. Successful completion depends upon overcoming substantial risks, including, but not limited to, risks relating to siting, financing, engineering and construction, permitting, governmental approvals, commissioning delays, or the potential for termination of the power sales contract as a result of a failure to meet certain milestones. For additional information regarding our projects under construction see Item 1.—*Business—Our Organization and Segments* included in this Form 10-K.

In certain cases, our subsidiaries may enter into obligations in the development process even though the subsidiaries have not yet secured financing, power purchase arrangements, or other aspects of the development process. For example, in certain cases, our subsidiaries may instruct contractors to begin the construction process or seek to procure equipment even where they do not have financing or a power purchase agreement in place (or conversely, to enter into a power purchase, procurement or other agreement without financing in place). If the project does not proceed, our subsidiaries may remain obligated for certain liabilities even though the project will not proceed. Development is inherently uncertain and we may forgo certain development opportunities and we may undertake significant development costs before determining that we will not proceed with a particular project. We believe that capitalized costs for projects under development are recoverable; however, there can be no assurance that any individual project will be completed and reach commercial operation. If these development efforts are not successful, we may abandon a project under development and write off the costs incurred in connection with such project. At the time of abandonment, we would expense all capitalized development costs incurred in connection therewith and could incur additional losses associated with any related contingent liabilities.

In some of our joint venture projects and businesses, we have granted protective rights to minority shareholders or we own less than a majority of the equity in the project or business and do not manage or otherwise control the project or business, which entails certain risks.

We have invested in some joint ventures where 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 in every instance 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 where we do have majority control of the voting securities, we have entered into shareholder agreements granting protective 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 which are different from the decisions our subsidiaries would make if they operated independently and could impact the profitability and value of these joint ventures. In addition, in the event that a joint venture partner becomes insolvent or bankrupt or is otherwise unable to meet its obligations to the joint venture or its share of liabilities at the joint venture, we may be subject to joint and several liability for these joint ventures, if and to the extent provided for in our governing documents or applicable law.

Our renewable energy projects and other initiatives face considerable uncertainties, including development, operational, and regulatory challenges.

Wind, solar, and energy storage projects are subject to substantial risks. Projects of this nature have been developed through advancement in technologies which may not be proven or whose commercial application is limited, and which are unrelated to our core business. Some of these business lines are dependent upon favorable regulatory incentives to support continued investment, and there is significant uncertainty about the extent to which such favorable regulatory incentives will be available in the future.

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 example, for our wind projects, wind resource estimates are based on historical experience when available and on wind resource studies conducted by an independent engineer, and are not expected to reflect actual wind energy production in any given year.

As a result, these types of renewable energy projects face considerable risk relative to our core business, including the risk that favorable regulatory regimes expire or are adversely modified. In addition, because certain of these projects depend on technology outside of our expertise in generation and utility businesses, there are risks associated with our ability to develop and manage such projects profitably. Furthermore, at the development or acquisition stage, because of the nascent nature of these industries or the limited experience with the relevant technologies, 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. Even where available, many of our renewable projects sell power under a Feed-in-Tariff, which may be eliminated or reduced, which can impact the profitability of these projects, or make money through the sale of Emission Reductions products, such as Certified Emissions

Reductions, Renewable Energy Certificates or Renewable Obligation Certificates, and the price of these products may be volatile. 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 these projects or obtain third party financing for these projects.

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

As of December 31, 2017, the Company had approximately $1.1 billion of goodwill, which represented approximately 3.2% of the total assets on its Consolidated Balance Sheets. Goodwill is not amortized, but is evaluated for impairment at least annually, or more frequently if impairment indicators are present. We may be required to evaluate the potential impairment of goodwill outside of the required annual evaluation process if we experience situations, including but not limited to: deterioration in general economic conditions, or our operating or regulatory environment; increased competitive environment; increase in fuel costs, particularly when we are unable to pass through the impact to customers; negative or declining cash flows; loss of a key contract or customer, particularly when we are unable to replace it on equally favorable terms; divestiture of a significant component of our business; or adverse actions or assessments by a regulator. These types of events and the resulting analyses could result in goodwill impairment, which could substantially affect our results of operations for those periods. Additionally, goodwill may be impaired if our acquisitions do not perform as expected. See the risk factor *Our acquisitions may not perform as expected* for further discussion.

Long-lived assets are initially recorded at fair value and are amortized or depreciated over their estimated useful lives. Long-lived assets are evaluated for impairment only when impairment indicators, similar to those described above for goodwill, are present, whereas goodwill is also evaluated for impairment on an annual basis.

Certain of our businesses are sensitive to variations in weather.

Our businesses are affected by variations in general weather patterns and unusually severe weather. Our businesses forecast electric sales on the basis of normal 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.

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. If hydrological conditions result in droughts or other conditions that negatively affect our hydroelectric generation business, our results of operations could be materially adversely affected.

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

Our business is heavily reliant on electronic systems and network technologies to operate our generation and transmission infrastructure. We also use various financial, accounting and other infrastructure systems. Our infrastructure may be targeted by nation states, hacktivists, criminals, insiders or terrorist groups. Such an attack may result in interruption of operations, property damage, our ability to control our infrastructure assets, release of sensitive customer information and limited communications with third parties. Any loss or corruption of confidential or proprietary data through such breach may:

- impair our reputation;
- impact our operations and strategic objectives;
- expose us to legal claims;
- result in substantial revenue loss; and
- require extensive repair and restoration costs for additional security measures to avert future cyber-attacks.

In addition, a breach of our financial and accounting systems could impact 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 some measures to comply with mandatory regulatory reliability standards, and we also maintain insurance coverage to mitigate some of these risks. To date, we have not seen material impact on our business or operations due to a cyber-attack; however we cannot guarantee that our security measures will prevent future cyber-attacks and security breaches. 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 security policies for the Company and its third-party providers.

Our acquisitions may not perform as expected.

Historically, acquisitions have been a significant part of our growth strategy. We may continue to grow our business through acquisitions. Although acquired businesses may have significant operating histories, we will have a limited or no history of owning and operating many of these businesses and possibly limited or no experience operating in the country or region where these businesses are located. 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;
- such businesses will perform as expected;
- integration or other one-time costs will not be greater than expected;
- we will not incur unforeseen obligations or liabilities;
- such businesses will generate sufficient cash flow to support the indebtedness incurred to acquire them or the capital expenditures needed to develop them; or
- the rate of return from such businesses will justify our decision to invest capital to acquire them.

Risks associated with Governmental Regulation and Laws

Our operations are subject to significant government regulation and our business and results of operations 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 any ability to obtain expected or contracted increases in electricity tariff or contract rates 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 at our utilities 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 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 what is an appropriate rate of return on invested capital or a determination that a utility's operating income or the rates it charges customers are too high, resulting in a reduction of rates or consumer rebates;
- changes in the definition or determination of controllable or non-controllable costs;
- adverse changes in tax law;
- changes in law or regulation which limit or otherwise affect the ability of our counterparties (including sovereign or private parties) to fulfill their obligations (including payment obligations) to us or our subsidiaries;
- changes in environmental law which impose additional costs or limit the dispatch of our generating facilities within our subsidiaries;
- 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;
- other changes related to licensing or permitting which affect our ability to conduct business; or
- other changes that impact the short- or long-term price-setting mechanism in the markets where we operate.

Any of the above events may result in lower margins for the affected businesses, which can adversely affect our business.

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. On July 21, 2010, President Obama signed the Dodd-Frank Act. The Dodd-Frank Act substantially expands the regulation regarding the trading, clearing and reporting of derivative transactions, and the Dodd-Frank Act provides for commercial end-user exemptions which may apply to our derivative transactions. However, even with the exemption, the Dodd-Frank Act could still have a material adverse impact on the Company, as the regulation of derivatives (which includes capital and margin requirements for non-exempt companies), could limit the availability of derivative transactions that we use to reduce interest rate, commodity and currency risks, which would increase our exposure to these risks. The impacts described above could also result from our (or our subsidiaries') efforts to comply with European Market Infrastructure Regulation, which includes regulations related to the trading, reporting and clearing of derivatives. It is also possible that additional similar regulations may be passed in other jurisdictions where we conduct business. Any of these outcomes could have a material adverse effect on the Company.

Our business in the United States is subject to the provisions of various laws and regulations administered in whole or in part by the FERC and NERC, including PURPA, the Federal Power Act, and the EPAct 2005. Actions by the FERC, NERC and by state utility commissions can have a material effect on our operations.

Several of our generation businesses in the U.S. currently operate QFs as defined under PURPA. These businesses entered into long-term contracts with electric utilities that had a mandatory obligation under PURPA to purchase power from QFs at the utility's avoided cost (i.e., the costs for both energy and capital investment that would have been incurred by the purchasing utility if that utility had to provide its own generating capacity or purchase it from another source). EPAct 2005 authorizes the FERC to eliminate the obligation of electric utilities under Section 210 of PURPA to enter into new contracts for the purchase or sale of electricity from or to QFs if certain market conditions are met. Pursuant to this authority, the FERC has instituted a rebuttable presumption that utilities located within the control areas of MISO, PJM , ISO New England, Inc., the New York Independent System Operator, Inc., and ERCOT are not required to purchase or sell power from or to QFs above a certain size. In addition, the FERC is authorized under EPAct 2005 to remove the purchase/sale obligations of individual utilities on a case-by-case basis. While this law does not affect existing contracts, as a result of the changes to PURPA, our QFs may face a more difficult market environment when their current long-term contracts expire.

EPAct 2005 repealed PUHCA 1935 and enacted PUHCA 2005 in its place. PUHCA 1935 had the effect of requiring utility holding companies to operate in geographically proximate regions and therefore limited the range of potential combinations and mergers among utilities. By comparison, PUHCA 2005 has no such restrictions and simply provides the FERC and state utility commissions with enhanced access to the books and records of certain utility holding companies. The repeal of PUHCA 1935 removed barriers to mergers and other potential combinations which could result in the creation of large, geographically dispersed utility holding companies. These entities may have enhanced financial strength and therefore an increased ability to compete with us in the U.S. generation market.

In accordance with Congressional mandates in the EPAct 1992 and now in EPAct 2005, the FERC has strongly encouraged competition in wholesale electric markets. Increased competition may have the effect of lowering our operating margins. Among other steps, the FERC has encouraged RTOs and ISOs to develop demand response bidding programs as a mechanism for responding to peak electric demand. These programs may reduce the value of our peaking assets which rely on very high prices during a relatively small number of hours to recover their costs. Similarly, the FERC is 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.

While the FERC continues to promote competition, some state utility commissions have reversed course and begun to encourage the construction of generation facilities by traditional utilities to be paid for on a cost-of-service basis by retail ratepayers. Such actions have the effect of reducing sale opportunities in the competitive wholesale generating markets in which we operate.

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 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 utility businesses in the U.S. 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—US SBU—U.S. Businesses—U.S. Utilities* for further information on the regulation faced by our U.S. utilities.

Our businesses are subject to stringent environmental laws 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, among others. Failure to comply with such laws and regulations or to obtain or comply with any necessary environmental permits pursuant to such laws and regulations could result in fines or other sanctions. Environmental laws and regulations affecting power generation and distribution are complex and have tended to become more stringent over time. 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. See the various descriptions of these laws and regulations contained in Item 1.—*Business* of this Form 10-K. 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. 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 the Company 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 by such expenditures or any changes in domestic or foreign environmental laws and regulations.

Our businesses are subject to enforcement initiatives from environmental regulatory agencies.

The EPA has pursued an enforcement initiative against 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 a number of companies and has obtained settlements with many of these companies over such allegations. The allegations typically involve claims that a company made major modifications to a coal-fired generating unit without proper permit approval and without installing best available control technology. The principal, but not exclusive, focus of this EPA enforcement initiative is emissions of SO_2 and NO_x. In connection with this enforcement initiative, the EPA has imposed fines and required companies to install improved pollution control technologies to reduce emissions of SO_2 and NO_x. In addition to EPA enforcement, state regulatory agencies and non-governmental environmental organizations have pursued civil lawsuits against power plants in situations where the EPA has not taken such action. These civil suits have resulted in judgments and/or settlements that require the installation of expensive pollution controls or the accelerated retirement of certain electric generating units. There can be no assurance that foreign environmental regulatory agencies or environmental organizations in countries in which our subsidiaries operate will not pursue similar enforcement initiatives under relevant laws and regulations.

Regulators, politicians, non-governmental organizations and other private parties have expressed concern about greenhouse gas, or GHG, emissions and the potential risks associated with climate change and are taking actions which could have a material adverse impact on our consolidated results of operations, financial condition and cash flows.

As discussed in Item 1.—*Business*, at the international, federal and various regional and state levels, rules are in effect and policies are under development to regulate GHG emissions, thereby effectively imposing a cost on such emissions in order to create financial incentives to reduce them. In 2017, the Company's subsidiaries operated businesses which had total CO_2 emissions of approximately 62.88 million metric tonnes, approximately 28.7 million of which were emitted by businesses located in the U.S. (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. The estimated annual CO_2 emissions from fossil fuel-fired electric power generation facilities of the Company's subsidiaries that are in construction or development and have received the necessary air permits for commercial operations are approximately 10.3 million metric tonnes (ownership adjusted). This overall estimate is based on a number of projections and assumptions that may prove to be incorrect, such as the forecasted dispatch, anticipated plant efficiency, fuel type, CO_2 emissions rates and our subsidiaries' achieving completion of such construction and development projects. However, it is certain that the 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. Because there is significant uncertainty regarding these estimates, actual emissions from these projects under construction or development may vary substantially from these estimates.

The non-utility, generation subsidiaries of the Company often seek to pass on any costs arising from CO_2 emissions to contract counterparties, but there can be no assurance that such subsidiaries of the Company will effectively pass such costs onto the contract counterparties or that the cost and burden associated with any dispute over which party bears such costs would not be burdensome and costly to the relevant subsidiaries of the Company. The utility subsidiaries of the Company may seek to pass on any costs arising from CO_2 emissions to customers, but there can be no assurance that such subsidiaries of the Company will effectively pass such costs to the customers, or that they will be able to fully or timely recover such costs.

Foreign, federal, state or regional regulation of GHG emissions could have a material adverse impact on the Company's financial performance. The actual impact on the Company's financial performance and the financial performance of the Company's subsidiaries will depend on a number of factors, including among others, 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. As a result of these factors, our cost of compliance could be substantial and could have a material adverse impact on our results of operations.

In January 2005, based on European Community "Directive 2003/87/EC on Greenhouse Gas Emission Allowance Trading," the EU ETS commenced operation as the largest multi-country GHG emission trading scheme in the world. On February 16, 2005, the Kyoto Protocol became effective. The Kyoto Protocol requires all developed countries that have ratified it to substantially reduce their GHG emissions, including CO_2. However, the United States never ratified the Kyoto Protocol and, to date, compliance with the Kyoto Protocol and the EU ETS has not had a material adverse effect on the Company's consolidated results of operations, financial condition and cash flows.

In December 2015, the Parties to the United Nations Framework Convention on Climate Change ("UNFCCC") convened for the 21st Conference of the Parties in Paris, France. The result was the so-called Paris Agreement. The Paris Agreement has a long-term goal of keeping the increase in global average temperature to well below 2°C above pre-industrial levels. In furtherance of this goal, participating countries submitted comprehensive national climate action plans and have agreed to meet every five years to set more ambitious targets as required by science, to report to each other and the public on how well they are doing to implement their targets and to track progress towards the long-term goal through a robust transparency and accountability system. We anticipate that the Paris Agreement will continue the trend toward efforts to de-carbonize the global economy and to further limit GHG emissions, including in those countries where the Company does business. It is difficult to predict the nature, timing and scope of such regulation but it could have a material adverse effect on the Company's financial performance.

In the U.S., there currently is no federal legislation imposing mandatory GHG emission reductions (including for CO_2) affecting the electric power generation facilities of the Company's subsidiaries. However, in 2011, 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, but only if they also must obtain a new source review permit for increases in other regulated pollutants. Additionally, in 2015, the EPA promulgated a rule establishing New Source Performance Standards for CO_2 emissions for newly constructed and modified/reconstructed fossil-fueled EUSGUs larger than 25 MW. Also in 2015, the EPA promulgated the CPP, which is applicable to preexisting EUSGUs, and requires interim reductions beginning in 2022, with full compliance achieved by 2030. Under the CPP, states are required to develop and submit plans that establish performance standards or, through emissions trading programs, otherwise meet a state-wide emissions rate average or mass-based goal. These actions have been challenged in Court and the current Administration has announced plans to significantly amend or rescind the rules. For further discussion of the regulation of GHG emissions, including the

U.S. Supreme Court's issued order staying implementation of the CPP, and the EPA's proposal to rescind the CPP, see Item 1.—*Business—Environmental and Land-Use Regulations—United States Environmental and Land-Use Legislation and Regulations—Greenhouse Gas Emissions* above.

Such regulations, and in particular regulations applying to modified or existing EUSGUs, could increase our costs directly and indirectly and have a material adverse effect on our business and/or results of operations. See Item 1.—*Business* of this Form 10-K for further discussion about these environmental agreements, laws and regulations.

At the state level, the RGGI, a cap-and-trade program covering CO_2 emissions from electric power generation facilities in the Northeast, became effective in January 2009, and California has adopted comprehensive legislation and regulation that requires GHG reductions from multiple industrial sectors, including the electric power generation industry. At this time, other than with regard to RGGI (further described below) and proposed Hawaii regulations relating to the collection of fees on GHG emissions, the impact of both of which we do not expect to be material, the Company cannot estimate the costs of compliance with U.S. federal, regional or state GHG emissions reduction legislation or initiatives, due to the fact that most of these proposals are not being actively pursued or are in the early stages of development and any final regulations or laws, if adopted, could vary drastically from current proposals; in the case of California, we anticipate no material impact due to the fact that we expect such costs will be passed through to our offtakers under the terms of existing tolling agreements.

The auctions of RGGI allowances needed by power generators to comply with state programs implementing RGGI occur approximately every quarter. Our subsidiary in Maryland is our only subsidiary that was subject to RGGI in 2017. Of the approximately 28.7 million metric tonnes of CO_2 emitted in the United States by our subsidiaries in 2017 (ownership adjusted), approximately 1.2 million metric tonnes were emitted by our subsidiary in Maryland. The Company estimates that the RGGI compliance costs could be approximately $3.5 million for 2018. There is a risk that our actual compliance costs under RGGI will differ from our estimates by a material amount and that our model could underestimate our costs of compliance.

In addition to government regulators, other groups such as politicians, environmentalists and other private parties have expressed increasing concern about GHG emissions. For example, certain financial institutions have expressed concern about providing financing for facilities which would emit GHGs, which can affect our ability to obtain capital, or if we can obtain capital, to receive it on commercially viable terms. Further, rating agencies may decide to downgrade our credit ratings based on the emissions of the businesses operated by our subsidiaries or increased compliance costs which could make financing unattractive. In addition, plaintiffs have brought tort lawsuits against the Company because of its subsidiaries' GHG emissions. While the litigation mentioned has been dismissed, it is impossible to predict whether similar future lawsuits are likely to prevail or result in damages awards or other relief. Consequently, it is impossible to determine whether such lawsuits are likely to have a material adverse effect on the Company's consolidated results of operations and financial condition.

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, changes and variability in precipitation and in the intensity and frequency of extreme weather events. Physical impacts may have the potential to significantly affect the Company's business and operations, and any such potential impact may render it more difficult for our businesses to obtain financing. For example, extreme weather events could result in increased downtime and operation and maintenance costs at the electric power generation facilities and support facilities of the Company's subsidiaries. Variations in weather conditions, primarily temperature and humidity also would be expected to affect the energy needs of customers. A decrease in energy consumption could decrease the revenues of the Company's subsidiaries. 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. Changes in the temperature of lakes and rivers and changes in precipitation that result in drought could adversely affect the operations of the fossil fuel-fired electric power generation facilities of the Company's subsidiaries. Changes in temperature, precipitation and snow pack conditions also could affect the amount and timing of hydroelectric generation.

In addition to potential physical risks noted by the Intergovernmental Panel on Climate Change, there could be damage to the reputation of the Company due to public perception of GHG emissions by the Company's subsidiaries, and any such negative public perception or concerns could ultimately result in a decreased demand for electric power generation or distribution from our subsidiaries. The level of GHGs emitted by subsidiaries of the Company is not a factor in the compensation of executives of the Company.

If any of the foregoing risks materialize, costs may increase or revenues may decrease and there could be a material adverse effect on the electric power generation businesses of the Company's subsidiaries and on the Company's consolidated results of operations, financial condition and cash flows.

Tax legislation initiatives or challenges to our tax positions could adversely affect our results of operations and financial condition.

Our subsidiaries have operations in the U.S. and various non-U.S. jurisdictions. As such, we 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 affect our overall tax positions regarding income or other taxes. There can be no assurance that our effective tax rate or tax payments will not be adversely affected by these legislative measures.

The Tax Cuts and Jobs Act (the "2017 Act") enacted December 22, 2017 introduced significant changes to current U.S. federal tax law, including but not limited to lowering the corporate income tax rate, introducing new limits on interest expense deductibility, and changing the way in which foreign earnings are taxed. These changes are complex and are subject to additional guidance to be issued by the U.S. Treasury and the Internal Revenue Service. In addition, the reaction to the federal tax changes by the individual states is evolving. Our interpretations and assumptions around U.S. tax reform may evolve in future periods as further administrative guidance and regulations are issued, which may materially affect our effective tax rate or tax payments. For further details, please see Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties* in this Form 10-K.

Additionally, longstanding international tax norms that determine how and where cross-border international trade is subjected to tax are evolving. The Organization for Economic Cooperation and Development ("OECD"), in coordination with the G8 and G20, through its Base Erosion and Profit Shifting project (“BEPS") introduced a series of recommendations that many tax jurisdictions have adopted, or may adopt in the future, as law. As these and other tax laws, related regulations and double-tax conventions change, our financial results could be materially impacted. Given the unpredictability of these possible changes and their potential interdependency, it is very difficult to assess whether the overall effect of such potential tax changes would be cumulatively positive or negative for our earnings and cash flow, but such changes could adversely impact our results of operations.

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

We and our affiliates are subject to material litigation and regulatory proceedings.

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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 where 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 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, 2017.

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 is scheduled for March 15, 2018. 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 January 2012, the Brazil Federal Tax Authority issued an assessment alleging that AES Tietê had paid PIS and COFINS taxes from 2007 to 2010 at a lower rate than the tax authority believed was applicable. AES Tietê challenged the assessment on the grounds that the tax rate was set in the applicable legislation. In April 2013, the FIAC determined that AES Tietê should have calculated the taxes at the higher rate and that AES Tietê was liable for unpaid taxes, interest, and penalties totaling approximately R$1.17 billion ($353 million) as estimated by AES Tietê. AES Tietê appealed to the SIAC. In January 2015, the SIAC issued a decision in AES Tietê's favor, finding that AES Tietê was not liable for unpaid taxes. The public prosecutor subsequently filed an appeal, which was denied as untimely. The Tax Authority thereafter filed a motion for clarification of the SIAC's decision, which was denied in September 2016. The Tax Authority later filed a special appeal (“Special Appeal”), which was rejected as untimely in October 2016. The Tax Authority thereafter filed an interlocutory appeal with the Superior Administrative Court (“SAC”). In March 2017, the President of the SAC determined that the SAC would analyze the Special Appeal on timeliness and, if required, the merits. AES Tietê has challenged the Special Appeal. AES Tietê believes it has meritorious defenses to the claim and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In January 2015, DPL received NOVs from the EPA alleging violations of opacity at Stuart and Killen Stations, and in October 2015, IPL received a similar NOV alleging violations at Petersburg Station. In February 2017, the EPA issued a second NOV for DPL Stuart Station, alleging violations of opacity in 2016. Moreover, in February 2016, IPL received an NOV from the EPA alleging violations of NSR and other CAA regulations, the Indiana SIP, and the Title V operating permit at Petersburg Station. It is too early to determine whether the NOVs could have a material impact on our business, financial condition or results of our operations. IPL would seek recovery of any operating or capital expenditures, but not fines or penalties, related to air pollution control technology to reduce regulated air emissions; however, there can be no assurances that we would be successful in this regard.

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 and has ordered AES Redondo Beach to restore the site. Additional potential outcomes of the CCC determination could include an order requiring AES Redondo Beach to fund a wetland mitigation project and/or pay fines or penalties. AES Redondo Beach believes that it has meritorious arguments and intends to vigorously prosecute such lawsuit, but there can be no assurances that it will be successful.

In October 2015, Ganadera Guerra, S.A. (“GG”) and Constructora Tymsa, S.A. (“CT”) filed separate lawsuits against AES Panama in the local courts of Panama. The claimants allege that AES Panama profited from a hydropower facility (La Estrella) being partially located on land owned initially by GG and currently by CT, and that AES Panama must pay compensation for its use of the land. The damages sought from AES Panama are approximately $685 million (GG) and $100 million (CT). In October 2016, the court dismissed GG's claim because of GG's failure to comply with a court order requiring GG to disclose certain information. GG has refiled its lawsuit. Also, there are ongoing administrative proceedings concerning whether AES Panama is entitled to acquire an easement over the land and whether AES Panama can continue to occupy the land. AES Panama believes it has meritorious defenses and claims and will assert them vigorously; however, there can be no assurances that it will be successful in its efforts.

In January 2017, the Superintendencia del Medio Ambiente ("SMA") issued a Formulation of Charges asserting that Alto Maipo is in violation of certain conditions of the Environmental Approval Resolution ("RCA") governing Alto Maipo's hydropower project, for, among other things, operating vehicles at unauthorized times and failing to mitigate the impact of water intrusion during tunnel construction. In February 2017, Alto Maipo submitted a compliance plan to the SMA which, if approved by the agency, would resolve the matter without materially impacting construction of the project. In June 2017, the SMA issued a resolution detailing its comments on the compliance plan. Alto Maipo responded to the SMA's comments in July 2017. In January 2018, the SMA requested additional information from Alto Maipo relating to the compliance plan and Formulation of Charges. In February 2018, Alto Maipo submitted certain information to the SMA, which is under consideration by the agency. The outcome of this matter is uncertain, but an adverse decision by the SMA could have a negative impact on the construction of the project. Alto Maipo will pursue its interests vigorously in this matter; however, there can be no assurance that it will be successful in its efforts.

In June 2017, Alto Maipo terminated one of its contractors, Constructora Nuevo Maipo S.A. ("CNM"), given CNM's stoppage of tunneling works, its failure to produce a completion plan, and its other breaches of contract. Alto Maipo also initiated arbitration against CNM to recover excess completion costs and other damages relating to these breaches. CNM subsequently initiated a separate arbitration, seeking a declaration that its termination was wrongful, damages, and other relief. CNM has not supported its alleged damages, but it has asserted that it is entitled to recover over $20 million in damages, legal costs, and approximately $73 million that was drawn by Alto Maipo under letters of credit. The arbitrations have been consolidated into a single action. The evidentiary hearing is scheduled for May 20-31, 2019. In the interim, CNM requested that the arbitral Tribunal issue an order requiring Alto Maipo to immediately return or escrow the letter of credit funds. In February 2018, the Tribunal denied CNM's request for interim relief. However, the ultimate merits of CNM's arbitration claims will be decided after the May 2018 hearing, including in relation to the letters of credit. In addition, CNM is attempting to seek relief in the Chilean court of appeals concerning the draws on the letters of credit. That action is pending. Alto Maipo believes it has meritorious claims and defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In October 2017, the Ministry of Justice ("MOJ") of the Republic of Kazakhstan ("ROK") filed a lawsuit in the Specialized Economic Court of Eastern-Kazakhstan Region ("Economic Court") against Tau Power BV (an AES affiliate), Altai Power LLP (an AES affiliate), the Company, and two hydropower plants ("HPPs") previously under concession to Tau Power. In its lawsuit, the MOJ references a 2013 treaty arbitration award ("2013 Award") against the ROK concerning the ROK's energy laws. While its lawsuit is unclear, the MOJ appears to seek relief relating to the net income distributed by the HPPs during certain years of the concession period. In November 2017, the Economic Court issued a decision that purports to allow the MOJ to enforce the 2013 Award in Kazakhstan. The decision was affirmed on intermediate appeal. The AES defendants have appealed to the Kazakhstan Supreme Court. The AES defendants believe that the lawsuit is without merit and they will assert their defenses vigorously; however, there can be no assurances that they will be successful in their 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 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 Program does not have an expiration date and can be modified or terminated by the Board of Directors at any time. The cumulative repurchase from the commencement of the Program in July 2010 through December 31, 2017 is 154.3 million shares at 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, 2017, $246 million remained available for repurchase under the Program. No repurchases were made by The AES Corporation of its common stock during the year ended December 31, 2017. The Parent Company repurchased 8,686,983 and 39,684,131 shares of its common stock in 2016 and 2015, respectively.

Market Information

Our common stock is traded on the NYSE under the symbol "AES." The closing price of our common stock as reported by the NYSE on February 21, 2018, was $10.23 per share. The following tables present the high and low intraday sale prices of our common stock and cash dividends declared for the indicated periods.

	2017			2016		
	Sales Price		Cash Dividends	Sales Price		Cash Dividends
	High	Low	Declared	High	Low	Declared
First Quarter	$ 12.06	$ 10.93	$ 0.12	$ 11.80	$ 8.22	$ 0.11
Second Quarter	12.05	10.95	—	12.48	10.49	—
Third Quarter	11.66	10.60	0.12	13.32	11.85	0.11
Fourth Quarter	11.34	10.00	0.25	12.75	10.98	0.23

Dividends

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

Commencing the fourth quarter of	2017	2016	2015
Cash dividend	$0.13	$0.12	$0.11

The fourth quarter 2017 cash dividend is to be paid in the first quarter of 2018. There can be no assurance that 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.

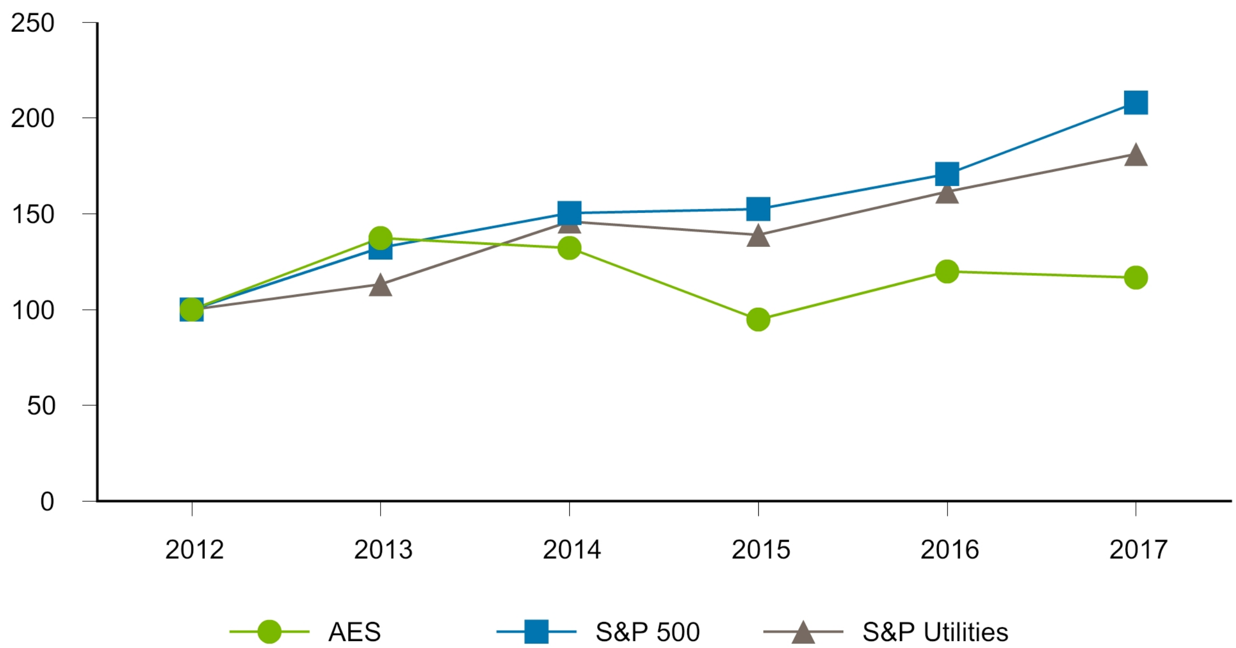
Under the terms of our senior secured credit facility, which we entered into with a commercial bank syndicate, we have limitations on our ability to pay cash dividends and/or repurchase stock. Our subsidiaries' ability to declare and pay cash dividends to us is also subject to certain limitations contained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

Holders

As of February 21, 2018, there were approximately 4,120 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 28 electric and gas utilities included in the S&P 500.

The five year total return chart assumes $100 invested on December 31, 2012 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. SELECTED FINANCIAL DATA

The following table presents our selected financial data as of the dates and for the periods indicated. This data should be read together with Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations* and the Consolidated Financial Statements and the notes thereto included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K. The selected financial data for each of the years in the five year period ended December 31, 2017 have been derived from our audited Consolidated Financial Statements. Prior period amounts have been restated to reflect discontinued operations in all periods presented. Prior to July 1, 2014, a discontinued operation was a component of the Company that either had been disposed of or was classified as held-for-sale and where the Company did not expect to have significant cash flows or significant continuing involvement with the component as of one year after its disposal or sale. Effective July 1, 2014, the Company adopted new accounting guidance under which the Company reports a business as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on the Company's operations and financial results when the business is sold or classified as held-for-sale. Please refer to Note 1 in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further explanation. Our historical results are not necessarily indicative of our future results.

Acquisitions, disposals, reclassifications and changes in accounting principles affect the comparability of information included in the tables below. Please refer to the Notes to the Consolidated Financial Statements included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further explanation of the effect of such activities. Please also refer to Item 1A.—*Risk Factors* of this Form 10-K and Note 25—*Risks and Uncertainties* to the Consolidated Financial Statements included in Item 8.—*Financial Statements and*

Supplementary Data of this Form 10-K for certain risks and uncertainties that may cause the data reflected herein not to be indicative of our future financial condition or results of operations.

SELECTED FINANCIAL DATA

	2017	2016	2015	2014	2013
Statement of Operations Data for the Years Ended December 31:	(in millions, except per share amounts)				
Revenue	$ 10,530	$ 10,281	$ 11,260	$ 12,604	$ 12,051
Income (loss) from continuing operations [1]	(148)	191	682	941	751
Income (loss) from continuing operations attributable to The AES Corporation, net of tax	(507)	(20)	318	678	264
Income (loss) from discontinued operations attributable to The AES Corporation, net of tax	(654)	(1,110)	(12)	91	(150)
Net income (loss) attributable to The AES Corporation	$ (1,161)	$ (1,130)	$ 306	$ 769	$ 114
Per Common Share Data					
Basic earnings (loss) per share:					
Income (loss) from continuing operations attributable to The AES Corporation, net of tax	$ (0.77)	$ (0.04)	$ 0.46	$ 0.94	$ 0.36
Income (loss) from discontinued operations attributable to The AES Corporation, net of tax	(0.99)	(1.68)	(0.01)	0.13	(0.21)
Basic earnings (loss) per share	$ (1.76)	$ (1.72)	$ 0.45	$ 1.07	$ 0.15
Diluted earnings (loss) per share:					
Income (loss) from continuing operations attributable to The AES Corporation, net of tax	$ (0.77)	$ (0.04)	$ 0.46	$ 0.94	$ 0.35
Income (loss) from discontinued operations attributable to The AES Corporation, net of tax	(0.99)	(1.68)	(0.02)	0.12	(0.20)
Diluted earnings (loss) per share	$ (1.76)	$ (1.72)	$ 0.44	$ 1.06	$ 0.15
Dividends Declared Per Common Share	$ 0.49	$ 0.45	$ 0.41	$ 0.25	$ 0.17
Cash Flow Data for the Years Ended December 31:					
Net cash provided by operating activities	$ 2,489	$ 2,884	$ 2,134	$ 1,791	$ 2,715
Net cash used in investing activities	(2,749)	(2,108)	(2,366)	(656)	(1,774)
Net cash provided by (used in) financing activities	43	(747)	28	(1,262)	(1,136)
Total (decrease) increase in cash and cash equivalents	(295)	26	(231)	(119)	(253)
Cash and cash equivalents, ending	949	1,244	1,218	1,517	1,636
Balance Sheet Data at December 31:					
Total assets	$ 33,112	$ 36,124	$ 36,545	$ 38,676	$ 40,100
Non-recourse debt (noncurrent)	13,176	13,731	12,184	12,077	11,486
Non-recourse debt (noncurrent)—Discontinued operations	—	758	772	1,226	1,629
Recourse debt (noncurrent)	4,625	4,671	4,966	5,047	5,485
Redeemable stock of subsidiaries	837	782	538	78	78
Retained earnings (accumulated deficit)	(2,276)	(1,146)	143	512	(150)
The AES Corporation stockholders' equity	2,465	2,794	3,149	4,272	4,330

(1) Includes pre-tax impairment expense of $537 million, $1.1 billion, $602 million, $383 million, and $596 million for the years ended December 31, 2017, 2016, 2015, 2014 and 2013, respectively. See Note 8—*Goodwill and Other Intangible Assets* and Note 19—*Asset Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

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

Executive Summary

Diluted loss per share from continuing operations for the year ended December 31, 2017 was $0.77, an increase of $0.73 compared to the year ended December 31, 2016. The increase was primarily due to a one-time transition tax on foreign earnings following the enactment of the U.S. Tax Cuts and Jobs Act in the fourth quarter of 2017. This impact was partially offset by lower impairment expense, primarily at DPL in the US SBU. Adjusted EPS, a non-GAAP financial measure, for the year ended December 31, 2017 increased $0.14 to $1.08, reflecting higher margins, primarily at the MCAC SBU, and contributions from new businesses in the U.S. and MCAC.

Strategic Priorities

As a result of our efforts to decrease our exposure to coal-fired generation and increase our portfolio of renewables, energy storage, and natural gas capacity, we are significantly reducing our carbon intensity. In 2017, AES and AIMCo completed the joint acquisition of sPower, the largest independent solar developer in the United States. In addition, we announced the sale or retirement of 4.5 GW of mostly merchant coal-fired generation, representing 31% of our coal-fired capacity.

In February 2018, we announced a reorganization as a part of our ongoing strategy to simplify our portfolio, optimize our cost structure, and reduce our carbon intensity. Reflecting this simplified portfolio, we will manage our global operations separate from our growth and commercial activities.

Overview of 2017 Results and Strategic Performance

Earnings Per Share and Free Cash Flow Results in 2017 (in millions, except per share amounts)

Years Ended December 31,	2017	2016	2015
Diluted earnings (loss) per share from continuing operations	$ (0.77)	$ (0.04)	$ 0.46
Adjusted EPS (a non-GAAP measure) [1]	1.08	0.94	1.24
Net cash provided by operating activities	2,489	2,884	2,134
Free Cash Flow (a non-GAAP measure) [1]	1,921	2,244	1,628

(1) See reconciliation and definition under *SBU Performance Analysis—Non-GAAP Measures*.

Diluted loss per share from continuing operations increased to a loss per share of $0.77 primarily due to a higher effective tax rate as a result of the U.S. Tax Reform Law enacted on December 22, 2017, partially offset by prior year impairments at DPL.

Adjusted EPS, a non-GAAP measure, increased by 15% to $1.08 primarily driven by higher margins at our MCAC SBU, contributions from new solar projects in the US, a one-time allowance on a non-trade receivable recognized in 2016, and the favorable impact of the YPF legal settlement at AES Uruguaiana, which was partially offset by higher adjusted effective tax rate.

Net cash provided by operating activities decreased by 14% to $2.5 billion primarily driven the collection of $360 million of overdue receivables at Maritza in 2016 and additional investments in working capital at Eletropaulo of $189 million. These decreases were partially offset by the $98 million increase in operating margin, excluding non cash drivers, at the Andes SBU.

Free Cash Flow, a non-GAAP measure, decreased by 14% to $1.9 billion primarily driven by a $395 million decrease in net cash provided by operating activities.

Review of Consolidated Results of Operations

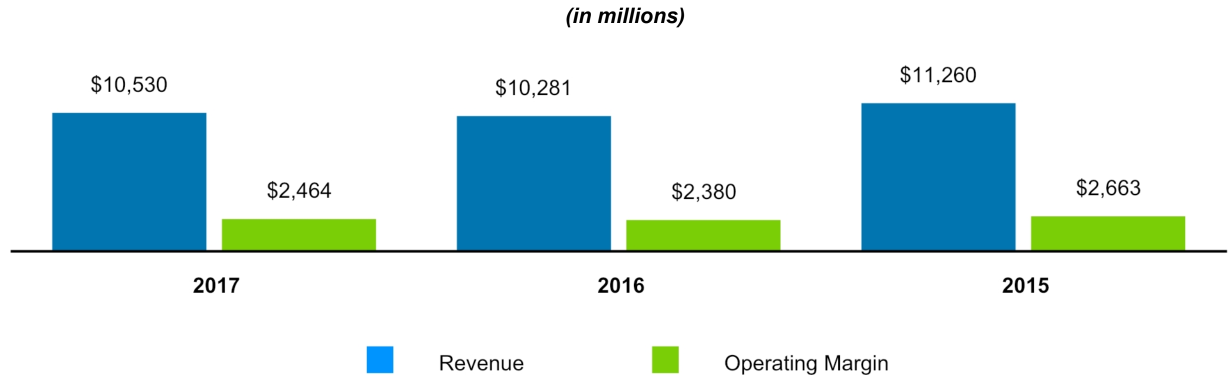
Years Ended December 31, (in millions, except per share amounts)	2017	2016	2015	% Change 2017 vs. 2016	% Change 2016 vs. 2015
Revenue:					
US SBU	$ 3,229	$ 3,429	$ 3,593	-6%	-5%
Andes SBU	2,710	2,506	2,489	8%	1%
Brazil SBU	542	450	962	20%	-53%
MCAC SBU	2,448	2,172	2,353	13%	-8%
Eurasia SBU	1,590	1,670	1,875	-5%	-11%
Corporate and Other	35	77	31	-55%	NM
Intersegment eliminations	(24)	(23)	(43)	-4%	47%
Total Revenue	10,530	10,281	11,260	2%	-9%
Operating Margin:					
US SBU	567	582	621	-3%	-6%
Andes SBU	658	634	618	4%	3%
Brazil SBU	203	186	397	9%	-53%
MCAC SBU	589	523	543	13%	-4%
Eurasia SBU	423	429	452	-1%	-5%
Corporate and Other	23	15	33	53%	-55%
Intersegment eliminations	1	11	(1)	91%	NM
Total Operating Margin	2,464	2,380	2,663	4%	-11%
General and administrative expenses	(215)	(194)	(196)	11%	-1%
Interest expense	(1,170)	(1,134)	(1,145)	3%	-1%
Interest income	244	245	256	—%	-4%
Loss on extinguishment of debt	(68)	(13)	(182)	NM	-93%
Other expense	(57)	(79)	(24)	-28%	NM
Other income	120	64	84	88%	-24%
Gain (loss) on disposal and sale of businesses	(52)	29	29	NM	—%
Goodwill impairment expense	—	—	(317)	—%	-100%
Asset impairment expense	(537)	(1,096)	(285)	-51%	NM
Foreign currency transaction gains (losses)	42	(15)	106	NM	NM
Income tax expense	(990)	(32)	(412)	NM	-92%
Net equity in earnings of affiliates	71	36	105	97%	-66%
INCOME (LOSS) FROM CONTINUING OPERATIONS	(148)	191	682	NM	-72%
Income (loss) from operations of discontinued businesses	(18)	151	80	NM	89%
Net loss from disposal and impairments of discontinued operations	(611)	(1,119)	—	-45%	NM
NET INCOME (LOSS)	(777)	(777)	762	—%	NM
Noncontrolling interests:					
Less: Income from continuing operations attributable to noncontrolling interests and redeemable stock of subsidiaries	(359)	(211)	(364)	70%	-42%
Less: Income from discontinued operations attributable to noncontrolling interests	(25)	(142)	(92)	-82%	54%
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ (1,161)	$ (1,130)	$ 306	3%	NM
AMOUNTS ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:					
Income (loss) from continuing operations, net of tax	$ (507)	$ (20)	$ 318	NM	NM
Loss from discontinued operations, net of tax	(654)	(1,110)	(12)	-41%	NM
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ (1,161)	$ (1,130)	$ 306	3%	NM
Net cash provided by operating activities	$ 2,489	$ 2,884	$ 2,134	-14%	35%
DIVIDENDS DECLARED PER COMMON SHARE	$ 0.49	$ 0.45	$ 0.41	9%	10%

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

Cost of sales includes costs incurred directly by the businesses in the ordinary course of business. Examples include electricity and fuel purchases, operations and maintenance costs, depreciation and amortization expense, 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, 2017

Consolidated Revenue — Revenue increased $249 million, or 2%, in 2017 compared to 2016 primarily driven by:

- $276 million in MCAC primarily due to the commencement of the combined cycle operations at Los Mina in June 2017 as well as higher rates in the Dominican Republic and higher pass through costs in El Salvador, partially offset by hurricane impacts at Puerto Rico; and
- $204 million in Andes primarily due to the start of commercial operations at Cochrane as well as higher availability at Argentina, partially offset by lower spot sales at Chivor.

These positive impacts were partially offset by a decrease of $200 million in the U.S. mainly due to lower retail tariffs as well as lower wholesale volume and price at DPL.

Consolidated Operating Margin — Operating margin increased $84 million, or 4%, in 2017 compared to 2016 primarily driven by:

- The favorable impact of FX of $39 million, primarily in Brazil, Argentina, and Colombia.

Excluding the FX impact mentioned above:

- $65 million in MCAC due to the commencement of the Los Mina combined cycle operations in June 2017 in the Dominican Republic as well as higher availability due to forced outages in 2016 at Mexico.

These positive impacts were partially offset by a decrease of $15 million in the U.S. driven by lower retail margin, lower volumes, and lower commercial availability at DPL as well as a negative impact at IPL mainly due to one-off accruals due to the implementation of new base rates in Q2 2016.

Year Ended December 31, 2016

Consolidated Revenue — Revenue decreased $979 million, or 9%, in 2016 compared to 2015 primarily driven by:

- The unfavorable FX impacts of $326 million, primarily in Argentina of $94 million, Kazakhstan of $63 million and Colombia of $54 million.

Excluding the FX impact mentioned above:

- $483 million in Brazil due to lower rates for energy sold under new contracts at Tietê as well as operations in 2015 but not in 2016 at Uruguaiana;
- $164 million in the U.S. primarily due to the sale of DPLER in January 2016 as well as lower rates at DPL, partially offset by higher retail rates at IPL;
- $141 million in MCAC primarily due to lower pass-through costs at El Salvador; and

- $95 million in Eurasia primarily due to lower pass-through costs at IPP4 in Jordan, partially offset by the full operations at Mong Duong in 2016 compared to Unit 1 in March 2015 with principal operations commencing in April 2015.

These decreases were partially offset by an increase of $165 million in Andes mainly due to the commencement of operations at Cochrane in Chile with Unit1 operational in July 2016 and principal operations in October.

Consolidated Operating Margin — Operating margin decreased $283 million, or 11%, in 2016 compared to 2015 primarily driven by:

- The unfavorable FX impacts of $88 million, primarily in Kazakhstan, Argentina, and Colombia.

Excluding the FX impact mentioned above:

- $198 million in Brazil driven by the revenue drivers above; and
- $39 million in the U.S. driven by the revenue drivers above.

These decreases were partially offset by an increase of $52 million in Andes driven by the revenue drivers above as well as lower spot prices at Gener Chile.

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

Consolidated Results of Operations — Other

General and administrative expenses

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

General and administrative expenses increased $21 million, or 11%, in 2017 from 2016 primarily due to severance costs related to workforce reductions associated with a major restructuring program, increased professional fees and increased business development activity.

General and administrative expenses decreased $2 million, or 1%, in 2016 from 2015 with no material drivers.

Interest expense

Interest expense increased $36 million, or 3%, in 2017 from 2016 primarily due to a $30 million increase at Andes SBU, driven by lower capitalized interest in 2017 due to Cochrane plant starting commercial operations in the second half of 2016.

Interest expense decreased $11 million, or 1% in 2016 from 2015 primarily due to a decrease in debt balance at the Parent Company and US SBU, partially offset by higher interest expense due to Mong Duong assets being placed in service, which ended the interest capitalization period at the Eurasia SBU.

Interest income

Interest income decreased $1 million in 2017 from 2016 with no material drivers.

Interest income decreased $11 million, or 4%, in 2016 from 2015 primarily due to prior year recognition of accumulated interest on VAT balances at the Andes SBU and lower short term investment balances at the Brazil SBU in 2016, partially offset by higher interest income recognized on the financing element of the service concession arrangement at Mong Duong in the Eurasia SBU, which became fully operational in April 2015.

Loss on extinguishment of debt

Loss on extinguishment of debt was $68 million for the year ended December 31, 2017 primarily related to losses of $92 million, $20 million, and $9 million on debt extinguishments at the Parent Company, AES Gener, and IPALCO, respectively. The loss was partially offset by a gain on early retirement of debt at Alicura of $65 million.

Loss on extinguishment of debt was $13 million for the year ended December 31, 2016. This loss was primarily related to losses of $14 million recognized on debt extinguishment at the Parent Company.

Loss on extinguishment of debt was $182 million for the year ended December 31, 2015. This loss was primarily related to losses of $105 million, $22 million, and $19 million recognized on debt extinguishments at the Parent Company, IPL, and the Dominican Republic, respectively.

Other income and expense

Other income increased $56 million, or 88%, in 2017 from 2016 primarily due to the favorable impact at Brazil SBU as a result of the settlement of legal proceeding at AES Uruguaiana related to YPF's breach of the parties’ gas supply agreement in 2017.

Other income decreased $20 million, or 24%, in 2016 from 2015 primarily due to gains on early contract termination in 2015.

Other expense decreased $22 million, or 28%, in 2017 from 2016 primarily due to the 2016 recognition of a full allowance on a non-trade receivable in the MCAC SBU as a result of payment delays. This decrease was partially offset by the 2017 loss on disposal of assets at DPL as a result of the decision to close the coal-fired and diesel-fired generating units at Stuart and Killen on or before June 1, 2018 and the write-off of water rights in the Andes SBU for projects that are no longer being pursued.

Other expense increased $55 million in 2016 from 2015 primarily due to the 2016 recognition of a full allowance on a non-trade receivable in the MCAC SBU as a result of payment delays.

See Note 18—*Other Income and Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Gain (loss) on disposal and sale of businesses

Loss on disposal and sale of businesses was $52 million for the year ended December 31, 2017 primarily due to the $49 million and $33 million loss on sale of Kazakhstan CHPs and hydroelectric plants, respectively, partially offset by the recognition of a $23 million gain related to the expiration of a contingency at Masinloc.

Gain on disposal and sale of businesses was $29 million for the year ended December 31, 2016 primarily due to the $49 million gain on sale of DPLER, partially offset by the $20 million loss on the deconsolidation of U.K. Wind.

Gain on disposal and sale of businesses was $29 million for the year ended December 31, 2015 primarily due to the $22 million gain on sale of Armenia Mountain.

Goodwill impairment expense

There were no goodwill impairments for the years ended December 31, 2017 or 2016.

Goodwill impairment expense was $317 million for the year ended December 31, 2015 due to a goodwill impairment at DP&L.

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

Asset impairment expense

Asset impairment expense decreased $559 million, or 51%, in 2017 from 2016 mainly driven by the prior year US SBU impairment of $859 million at DPL, partially offset by a $121 million impairment in the current year at Laurel Mountain as a result of a decline in forward pricing.

Asset impairment expense increased $811 million in 2016 from 2015 primarily due to asset impairments recognized during 2016 at DPL in the US SBU, resulting from lower forecasted revenues from the PJM capacity auction and higher anticipated environmental compliance costs.

See Note 19—*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,	2017	2016	2015
Mexico	$ 17	$ (8)	$ (6)
Philippines	15	12	8
Bulgaria	14	(8)	3
Chile	8	(9)	(18)
AES Corporation	3	(50)	(31)
Argentina	1	37	124
United Kingdom	(3)	13	11
Colombia	(23)	(8)	29
Other	10	6	(14)
Total [(1)]	$ 42	$ (15)	$ 106

(1) Includes gains of $21 million, $17 million and $247 million on foreign currency derivative contracts for the years ended December 31, 2017, 2016 and 2015, respectively.

The Company recognized net foreign currency transaction gains of $42 million for the year ended December 31, 2017 primarily driven by transactions associated with VAT activity in Mexico, the amortization of frozen embedded derivatives in the Philippines, and appreciation of the Euro in Bulgaria. These gains were partially offset by unfavorable foreign currency derivatives in Colombia.

The Company recognized net foreign currency transaction losses of $15 million for the year ended December 31, 2016 primarily due to remeasurement losses on intercompany notes, and losses on swaps and options at The AES Corporation. This loss was partially offset in Argentina, mainly due to the favorable impact of foreign currency derivatives related to government receivables.

The Company recognized net foreign currency transaction gains of $106 million for the year ended December 31, 2015 primarily due to foreign currency derivatives related to government receivables in Argentina and depreciation of the Colombian peso in Colombia. These gains were partially offset due to decreases in the valuation of intercompany notes at The AES Corporation and unfavorable devaluation of the Chilean peso in Chile.

Income tax expense

Income tax expense increased $958 million to $990 million in 2017 as compared to 2016. The Company's effective tax rates were 128% and 17% for the years ended December 31, 2017 and 2016, respectively.

The net increase in the 2017 effective tax rate was due primarily to expense related to the U.S. tax reform one-time transition tax and remeasurement of deferred tax assets. Further, the 2016 rate was impacted by the items described below.

Income tax expense decreased $380 million to $32 million in 2016 as compared to 2015. The Company's effective tax rates were 17% and 42% for the years ended December 31, 2016 and 2015, respectively.

The net decrease in the 2016 effective tax rate was due, in part, to the 2016 asset impairments in the U.S., as well as the devaluation of the peso in certain of our Mexican subsidiaries and the release of valuation allowance at certain of our Brazilian subsidiaries. These favorable items were partially offset by the unfavorable impact of Chilean income tax law reform enacted during the first quarter of 2016. Further, the 2015 rate was due, in part, to the nondeductible 2015 impairment of goodwill at DP&L and Chilean withholding taxes offset by the release of valuation allowance at certain of our businesses in Brazil, Vietnam and the U.S. See Note 19—*Asset Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional information regarding the 2016 U.S. asset impairments. See Note 20—*Income Taxes* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional information regarding the 2016 Chilean income tax law reform.

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 new U.S. corporate rate of 21% and a greater portion of our foreign earnings may be subject to current U.S. taxation under the new tax rules. 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 20—*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 earnings of affiliates

Net equity in earnings of affiliates increased $35 million, or 97%, in 2017 from 2016 primarily due to earnings at the sPower equity method investment purchased in 2017, partially offset by fixed asset impairments in 2017 at the Distributed Energy entities, accounted for as equity affiliates. The $42 million equity earnings recorded for the investment in sPower includes the allocation of $53 million of project income to AES through the application of the HLBV model. This income includes the impact of day one gain described in Note 1—*General and Summary of Significant Accounting Policies—Allocation of Earnings* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K. The net project income at sPower in the period after the acquisition was $20 million.

Net equity in earnings of affiliates decreased $69 million, or 66%, in 2016 from 2015 as a result of the restructuring of Guacolda in September 2015, which resulted in a $66 million benefit. No comparable transaction occurred in 2016.

See Note 7—*Investments In and Advances to Affiliates* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Net income (loss) from discontinued operations

Net loss from discontinued operations was $629 million for the year ended December 31, 2017 primarily due to the after-tax loss on deconsolidation of Eletropaulo of $611 million recognized in the fourth quarter of 2017. The remaining loss was due to a loss contingency recognized by our equity affiliate, partially offset by the income from operations of Eletropaulo prior to the date of deconsolidation.

Net loss from discontinued operations was $968 million for the year ended December 31, 2016 due to the sale of Sul, partially offset by the income from operations of Eletropaulo. The loss includes an after-tax loss on the impairment of Sul of $382 million recognized in the second quarter of 2016 and an additional after-tax loss on the sale of Sul of $737 million recognized upon disposal in October 2016. There was no significant loss from operations related to the Sul discontinued business.

Net income from discontinued operations was $80 million for the year ended December 31, 2015 primarily due to the income from operations of Eletropaulo. There was no significant loss from operations related to the Sul discontinued business.

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

Net income attributable to noncontrolling interests and redeemable stock of subsidiaries

Net income attributable to noncontrolling interests and redeemable stock of subsidiaries increased $148 million, or 70%, in 2017 from 2016 primarily due to:

- Asset impairment at Buffalo Gap I and II in 2016.

Net income attributable to noncontrolling interests and redeemable stock of subsidiaries decreased $153 million, or 42%, in 2016 from 2015 primarily due to:

- Lower earnings at Tietê,
- Asset impairments at Buffalo Gap I and II.

These decreases were offset by:

- Lower asset impairment at Buffalo Gap III in 2015.

Net income (loss) attributable to The AES Corporation

Net loss attributable to The AES Corporation increased $31 million, or 3%, in 2017 compared to 2016 as a result of:

- Impact due to U.S. Tax Reform Law enacted on December 22, 2017;
- Current year losses on sale of Kazakhstan CHPs and hydroelectric plants;
- Current year loss on deconsolidation of Eletropaulo;
- Current year impairments at Laurel Mountain, Kazakhstan CHPs and hydroelectric plants and Kilroot; and
- Higher loss on extinguishment of debt.

These increases were partially offset by:

- Prior year impairments at DPL;
- Prior year loss from discontinued operations as a result of the sale of Sul;
- Higher margin at our MCAC SBU;
- The favorable impact of the YPF legal settlement at AES Uruguaiana; and
- Higher gains on foreign currency transactions.

Net income attributable to The AES Corporation decreased $1.4 billion, to a loss of $1.1 billion in 2016 compared to income of $306 million in 2015 as result of:

- Impairments and loss on sale at discontinued businesses;
- Higher impairment expense on long lived assets;
- Lower operating margins at our US, Brazil and Eurasia SBUs;
- Lower equity in earnings of affiliates due to the 2015 restructuring at Guacolda; and
- Lower gains on foreign currency derivatives.

These decreases were partially offset by:

- Lower effective tax rate;
- Lower debt extinguishment expense; and
- Absence of goodwill impairment expense.

SBU Performance Analysis

Segments

We are organized into five market-oriented SBUs: **US** (United States), **Andes** (Chile, Colombia, and Argentina), **Brazil**, **MCAC** (Mexico, Central America, and the Caribbean), and **Eurasia** (Europe and Asia). In February 2018, we announced a reorganization as a part of our ongoing strategy to simplify our portfolio, optimize our cost structure, and reduce our carbon intensity. The evaluation of the impact this reorganization will have on our segment reporting structure is still ongoing.

Non-GAAP Measures

Adjusted Operating Margin, Adjusted PTC, Adjusted EPS, and Free Cash Flow 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.

For the year ending December 31, 2017, the Company changed the definition of Adjusted Operating Margin, Adjusted PTC and Adjusted EPS to exclude (a) associated benefits and costs due to acquisitions, dispositions, and early plant closures; including the tax impact of decisions made at the time of sale to repatriate sales proceeds; (b) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts, relocations, and office consolidation; and (c) tax benefit or expense related to the enactment effects of 2017 U.S. tax law reform.

We have excluded from our adjusted financial results costs associated with non-recurring restructuring initiatives to simplify the organization and improve efficiency. These restructuring initiatives 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.

The Company amended its Adjusted EPS definition to exclude the specific enactment effects of the transformational U.S. tax reform enacted on December 22, 2017. Such effects include a one-time transition tax on foreign earnings and the remeasurement of deferred tax assets and liabilities to the lower corporate tax rate. As permitted by the SEC in SAB 118, the Company recorded provisional amounts for these effects in its 2017 *income from continuing operations*. Changes in our estimates of these enactment effects may occur in future periods.

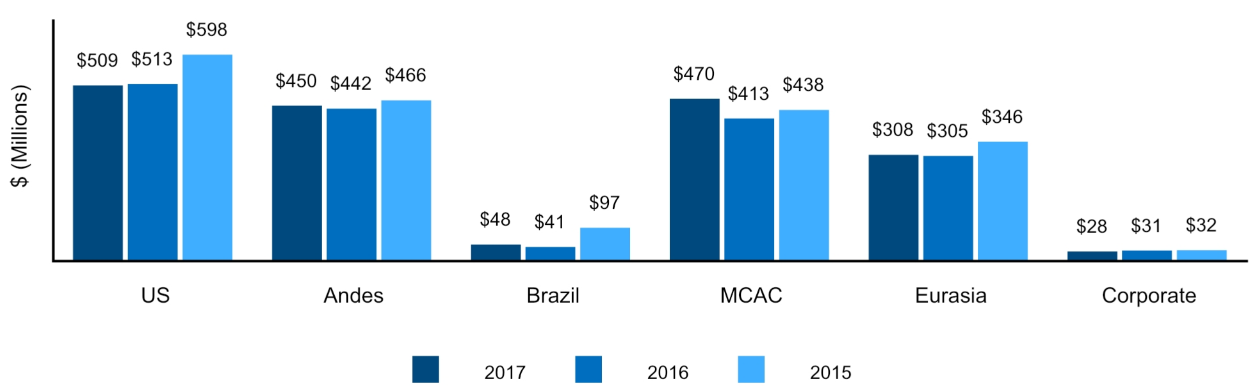
We believe excluding these benefits and costs better reflect the business performance by removing the variability caused by strategic decisions to dispose of or acquire business interests or close plants early, as well as the costs directly associated with a major restructuring program and the impact of the 2017 U.S. tax law reform, which affect results in a given period or periods. The Company has also reflected these changes in the comparative periods ending December 31, 2016 and December 31, 2015.

Adjusted Operating Margin

We define Adjusted Operating Margin as Operating Margin, adjusted for the impact of NCI, excluding (a) unrealized gains or losses related to derivative transactions; (b) gains, losses and associated benefits and costs due to dispositions and acquisitions of business interests, including early plant closures; and (c) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts, relocations, and office consolidation. See *Review of Consolidated Results of Operations* for definitions of Operating Margin and cost of sales.

The GAAP measure most comparable to Adjusted Operating Margin is Operating Margin. We believe that Adjusted Operating Margin better reflects the underlying business performance of the Company. Factors in this determination include the impact of NCI, where AES consolidates the results of a subsidiary that is not wholly owned by the Company, as well as the variability due to unrealized derivatives gains or losses related to derivative transactions and strategic decisions to dispose of or acquire business interests. Adjusted Operating Margin should not be construed as an alternative to Operating Margin, which is determined in accordance with GAAP.

Reconciliation of Adjusted Operating Margin (in millions)	Years Ended December 31,		
	2017	2016	2015
Operating Margin	$ 2,464	$ 2,380	$ 2,663
Noncontrolling interests adjustment	(690)	(644)	(705)
Unrealized derivative losses (gains)	(5)	9	19
Disposition/acquisition losses	22	—	—
Restructuring costs	22	—	—
Total Adjusted Operating Margin	$ 1,813	$ 1,745	$ 1,977



Adjusted PTC

We define Adjusted PTC as pre-tax income from continuing operations attributable to The AES Corporation excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses related to derivative transactions; (b) unrealized foreign currency gains or losses; (c) gains, losses and associated benefits and costs due to dispositions and acquisitions of business interests, including early plant closures; (d) losses due to impairments; (e) gains, losses and costs due to the early retirement of debt; and (f) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts, relocations, and office consolidation. 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.

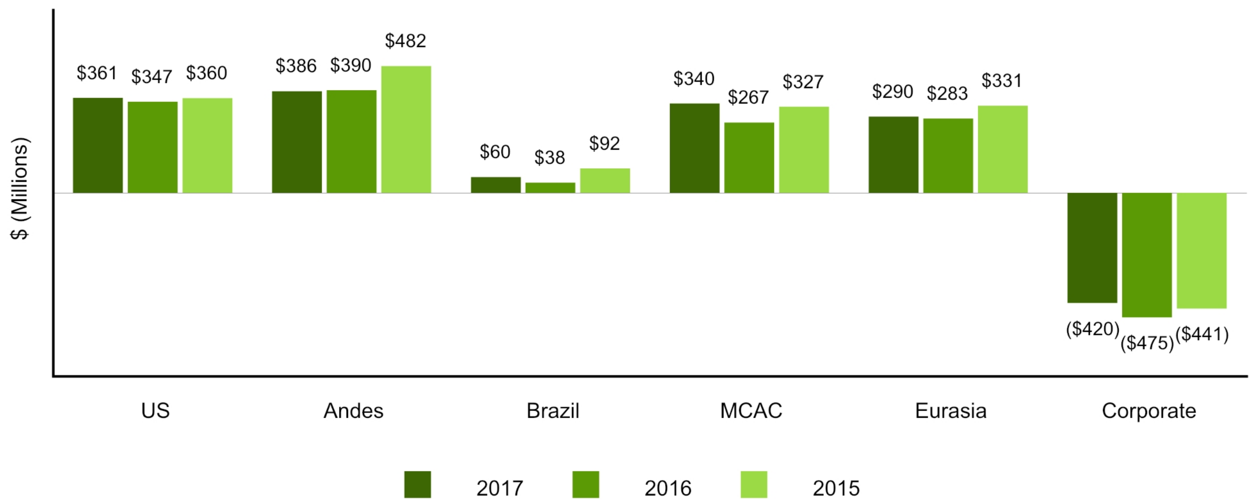
Adjusted PTC reflects the impact of NCI and excludes the items specified in the definition above. In addition to the revenue and cost of sales reflected in Operating Margin, Adjusted PTC includes the other components of our income statement, such as *general and administrative expenses* in the corporate 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 considered in the Company's internal evaluation of financial performance. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions, 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, earnings before tax 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. Adjusted PTC should not be construed as an alternative to *income from continuing operations attributable to The AES Corporation*, which is determined in accordance with GAAP.

Reconciliation of Adjusted PTC (in millions)	**Years Ended December 31,**		
	2017	**2016**	**2015**
Income (loss) from continuing operations, net of tax, attributable to The AES Corporation	$ (507)	$ (20)	$ 318
Income tax (benefit) expense attributable to The AES Corporation	828	(111)	263
Pre-tax contribution	321	(131)	581
Unrealized derivative gains	(3)	(9)	(166)
Unrealized foreign currency (gains) losses	(59)	22	95
Disposition/acquisition (gains) losses	123	6	(42)
Impairment losses	542	933	504
Loss on extinguishment of debt	62	29	179
Restructuring costs [(1)]	31	—	—
Total Adjusted PTC	$ 1,017	$ 850	$ 1,151

(1) In February 2018, the Company announced a reorganization as a part of its on-going strategy to simplify its portfolio, optimize its cost structure and reduce its carbon intensity.

Adjusted PTC



Adjusted EPS

We define Adjusted EPS as diluted earnings per share from continuing operations excluding gains or losses of both consolidated entities and entities accounted for under the equity method due to (a) unrealized gains or losses related to derivative transactions; (b) unrealized foreign currency gains or losses; (c) gains or losses and associated benefits and costs due to dispositions and acquisitions of business interests, including early plant closures, and the tax impact from the repatriation of sales proceeds; (d) losses due to impairments; (e) gains, losses and costs due to the early retirement of debt; (f) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts, relocations, and office consolidation; and (g) tax benefit or expense related to the enactment effects of 2017 U.S. tax law reform.

The GAAP measure most comparable to Adjusted EPS is diluted earnings per share from continuing operations. We believe that Adjusted EPS better reflects the underlying business performance of the Company and is considered in the Company's internal evaluation of financial performance. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions, 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 a loss from continuing operations of $0.77 and $0.04 per share for the years ended December 31, 2017 and 2016. For purposes of measuring diluted loss per share under GAAP, common stock equivalents were excluded from weighted average shares as their inclusion would be anti-dilutive. However, for purposes of computing Adjusted EPS, the Company has included the impact of dilutive common stock equivalents. The table below reconciles the weighted average shares used in GAAP diluted loss per share to the weighted average shares used in calculating the non-GAAP measure of Adjusted EPS.

Reconciliation of Denominator Used For Adjusted Earnings Per Share	**Years Ended December 31, 2017**			**Years Ended December 31, 2016**		
(in millions, except per share data)	**Loss**	**Shares**	**$ per share**	**Loss**	**Shares**	**$ per share**
GAAP DILUTED LOSS PER SHARE						
Loss from continuing operations attributable to The AES Corporation common stockholders	$ (507)	660	$ (0.77)	$ (25)	660	$ (0.04)
EFFECT OF DILUTIVE SECURITIES						
Restricted stock units	—	2	0.01	—	2	—
NON-GAAP DILUTED LOSS PER SHARE	$ (507)	662	$ (0.76)	$ (25)	662	$ (0.04)

Reconciliation of Adjusted EPS	**Years Ended December 31,**		
	2017	**2016**	**2015**
Diluted earnings (loss) per share from continuing operations	$ (0.76)	$ (0.04)	$ 0.46
Unrealized derivative gains	—	(0.01)	(0.24)
Unrealized foreign currency (gains) losses	(0.10)	0.03	0.15
Disposition/acquisition (gains) losses	0.19 (1)	0.01 (2)	(0.06) (3)
Impairment losses	0.82 (4)	1.41 (5)	0.73 (6)
Loss on extinguishment of debt	0.09 (7)	0.05 (8)	0.26 (9)
Restructuring costs	0.05	—	—
U.S. Tax Law Reform Impact	1.08 (10)	—	—
Less: Net income tax benefit on adjustments	(0.29) (11)	(0.51) (12)	(0.06) (13)
Adjusted EPS	$ 1.08	$ 0.94	$ 1.24

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(1) Amount primarily relates to loss on sale of Kazakhstan CHPs of $49 million, or $0.07 per share, realized derivative losses associated with the sale of Sul of $38 million, or $0.06 per share, loss on sale of Kazakhstan Hydroelectric plants of $33 million, or $0.05 per share, costs associated with early plant closure of DPL of $24 million, or $0.04 per share; partially offset by gain on Masinloc contingent consideration of $23 million or $0.03 per share and gain on sale of Zimmer and Miami Fort of $13 million, or $0.02 per share.

(2) Amount primarily relates to the loss on deconsolidation of UK Wind of $20 million, or $0.03 per share, and losses associated with the sale of Sul of $10 million, or $0.02; partially offset by the gain on sale of DPLER of $22 million, or $0.03 per share.

(3) Amount primarily relates to the gains on the sale of Armenia Mountain of $22 million, or $0.03 per share and from the sale of Solar Spain and Solar Italy of $7 million, or $0.01 per share.

(4) Amount primarily relates to asset impairment at Kazakhstan CHPs of $94 million, or $0.14 per share, at Kazakhstan hydroelectric plants of $92 million, or $0.14 per share, at Laurel Mountain wind farm of $121 million, or $0.18 per share, at DPL of $175 million, or $0.27 per share and at Kilroot of $37 million, or $0.05 per share.

(5) Amount primarily relates to asset impairments at DPL of $859 million, or $1.30 per share; $159 million at Buffalo Gap II ($49 million, or $0.07 per share, net of NCI); and $77 million at Buffalo Gap I ($23 million, or $0.03 per share, net of NCI).

(6) Amount primarily relates to the goodwill impairment at DPL of $317 million, or $0.46 per share, and asset impairments at Kilroot of $121 million ($119 million, or $0.17 per share, net of NCI), at Buffalo Gap III of $116 million ($27 million, or $0.04 per share, net of NCI), and at U.K. Wind (Development Projects) of $38 million ($30 million, or $0.04 per share, net of NCI).

(7) Amount primarily relates to losses on early retirement of debt at the Parent Company of $92 million, or $0.14 per share, at AES Gener of $20 million, or $0.02 per share, at IPALCO of $9 million or $0.01 per share; partially offset by a gain on early retirement of debt at Alicura of $65 million, or $0.10 per share.

(8) Amount primarily relates to the loss on early retirement of debt at the Parent Company of $19 million, or $0.03 per share.

(9) Amount primarily relates to the loss on early retirement of debt at the Parent Company of $116 million, or $0.17 per share and at IPL of $22 million ($17 million, or $0.02 per share, net of NCI).

(10) Amount relates to a one-time transition tax on foreign earnings of $675 million, or $1.02 per share and the remeasurement of deferred tax assets and liabilities to the lower corporate tax rate of $39 million, or $0.06 per share.

(11) Amount primarily relates to the income tax benefit associated with asset impairment losses of $148 million, or $0.22 per share in the twelve months ended December 31, 2017.

(12) Amount primarily relates to the income tax benefit associated with asset impairment of $332 million, or $0.50 per share in the twelve months ended December 31, 2016.

(13) Amount primarily relates to the income tax benefit associated with losses on extinguishment of debt of $55 million, or $0.08 per share in the twelve months ended December 31, 2015.

Free Cash Flow

We define Free Cash Flow as net cash from operating activities (adjusted for service concession asset capital expenditures) less maintenance capital expenditures (including non-recoverable environmental capital expenditures), net of reinsurance proceeds from third parties. Upon the Company's adoption of the accounting guidance for service concession arrangements effective January 1, 2015, capital expenditures related to service concession assets that would have been classified as investing activities on the Consolidated Statement of Cash Flows are now classified as operating activities. 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 on the adoption of this guidance.

We also exclude environmental capital expenditures that are expected to be recovered through regulatory, contractual or other mechanisms. An example of recoverable environmental capital expenditures is IPL's investment in MATS-related environmental upgrades that are recovered through a tracker. See Item 1.—*Business—US SBU—IPL—Environmental Matters* for details of these investments.

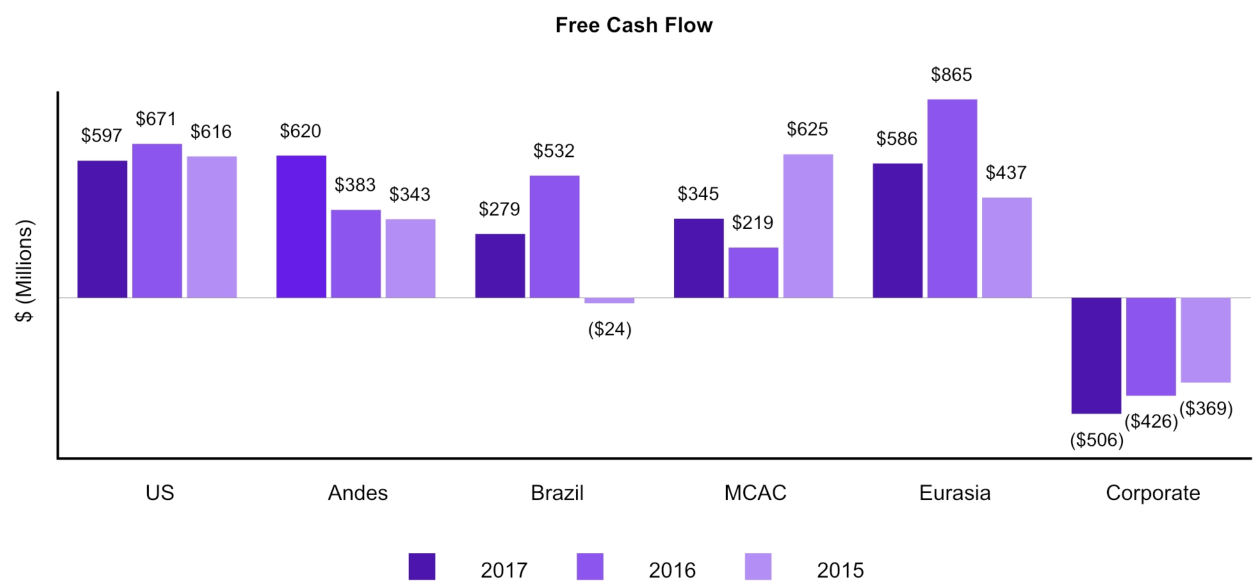
The GAAP measure most comparable to Free Cash Flow is net cash provided by operating activities. We believe that Free Cash Flow is a useful measure for evaluating our financial condition because it represents the amount of cash generated by the business after the funding of maintenance capital expenditures that may be available for investing in growth opportunities or for repaying debt.

The presentation of Free Cash Flow has material limitations. Free Cash Flow should not be construed as an alternative to net cash from operating activities, which is determined in accordance with GAAP. Free Cash Flow does not represent our cash flow available for discretionary payments because it excludes certain payments that are required or to which we have committed, such as debt service requirements and dividend payments. Our definition of Free Cash Flow may not be comparable to similarly titled measures presented by other companies.

Reconciliation of Free Cash Flow (in millions)	**Years Ended December 31,**		
	2017	**2016**	**2015**
Net Cash provided by operating activities	$ 2,489	$ 2,884	$ 2,134
Add: capital expenditures related to service concession assets [1]	6	29	165
Less: maintenance capital expenditures, net of reinsurance proceeds	(551)	(624)	(611)
Less: non-recoverable environmental capital expenditures [2]	(23)	(45)	(60)
Free Cash Flow	$ 1,921	$ 2,244	$ 1,628

[1] Service concession asset expenditures are included in net cash provided by operating activities, but are excluded from the Free Cash Flow non-GAAP metric.

[2] Excludes IPL's recoverable environmental capital expenditures of $54 million, $186 million and $262 million for the years ended December 31, 2017, 2016 and 2015, respectively.



US SBU

The following table summarizes Operating Margin, Adjusted Operating Margin, Adjusted PTC, and Free Cash Flow (in millions) for the periods indicated:

For the Years Ended December 31,	2017	2016	2015	$ Change 2017 vs. 2016	% Change 2017 vs. 2016	$ Change 2016 vs. 2015	% Change 2016 vs. 2015
Operating Margin	$ 567	$ 582	$ 621	$ (15)	-3%	$ (39)	-6%
Adjusted Operating Margin	509	513	598	(4)	-1%	(85)	-14%
Adjusted PTC	361	347	360	14	4%	(13)	-4%
Operating Cash Flow	776	912	845	(136)	-15%	67	8%
Free Cash Flow	597	671	616	(74)	-11%	55	9%
Free Cash Flow Attributable to NCI	41	57	25	(16)	-28%	32	NM

(1) See Item 1.— *Business* for the respective ownership interest for key businesses. In addition, AES owns 70% of IPL as of March 2016 compared to 75% beginning April 2015, 85% beginning in February 2015 and 100% prior to February 2015.

Fiscal year 2017 versus 2016

Operating Margin decreased $15 million, or 3%, which was driven primarily by the following (in millions):

IPL	
Decrease due to implementation of new base rates in Q2 2016 which resulted in a favorable change in accrual	$ (18)
Total IPL Decrease	**(18)**
DPL	
Lower retail margin due to lower regulated rates	(22)
Lower volumes primarily due to the shutdown of Stuart Unit 1 and lower commercial availability	(21)
Lower depreciation expense driven by lower PP&E carrying values from impairments in 2016 and 2017	26
Other	7
Total DPL Decrease	**(10)**
Other Business Drivers	**13**
Total US SBU Operating Margin Decrease	**$ (15)**

Adjusted Operating Margin decreased $4 million due to the drivers above, adjusted for NCI and excluding unrealized gains and losses on derivatives, one-time restructuring charges and costs associated with early plant closures.

Adjusted PTC increased $14 million driven by earnings from equity affiliates due to the 2017 acquisition of sPower, the Company's share of earnings at Distributed Energy due to new project growth, and an increase in insurance recoveries at DPL. The increase in Adjusted PTC was partially offset by the decrease of $4 million in Adjusted Operating Margin described above and a 2016 gain on contract termination at DP&L.

Free Cash Flow decreased $74 million, of which $16 million was attributable to NCI. The decrease was driven by changes in net cash provided by operating activities comprising:

- A decrease of $49 million in Operating Margin (net of $34 million of decreased depreciation);
- Increases in working capital of $144 million primarily related to an increase of $66 million in inventory balances as mild weather in 2015 drove inventory optimization efforts in 2016 and higher payments for purchased power and general accounts payable of $57 million at DPL and IPL; and
- Decreases in working capital of $86 million primarily driven by higher collections at IPL of $27 million due to the monetization of higher receivable balances from December 2016 generated by favorable weather and rates and additional regulatory asset payments of $31 million primarily driven by higher MISO cost collection.

Free Cash Flow was also impacted by a net increase of $33 million in other drivers, primarily related to a $51 million reduction in maintenance and non-recoverable environmental capital expenditures due to declining investment in our remaining coal generation capacity and $12 million in insurance proceeds at DPL.

Fiscal year 2016 versus 2015

Operating Margin decreased by $39 million, or 6%, which was driven primarily by the following (in millions):

US Generation	
Southland related to an increase in depreciation expense as a result of a change in estimated useful lives of the plants	$ (17)
Impact from sale of Armenia Mountain in July 2015	(10)
Warrior Run due to lower availability and higher maintenance cost primarily due to major outages in 2016	(8)
Laurel Mountain due to lower regulation dispatch as well as lower energy and regulation pricing	(8)
Other	(4)
Total US Generation Decrease	**(47)**
DPL	
Impact of lower wholesale prices and completion of DP&L's transition to a competitive-bid market	(42)
Decrease in RTO capacity and other revenues primarily due to lower capacity cleared in the auction	(21)
Lower depreciation expense due to June 2016 fixed asset impairment and decrease in generating facility maintenance and other expenses	17
Other	2
Total DPL Decrease	**(44)**
IPL	
Higher retail margin driven by environmental revenues and higher rates due to a new rate order	36
Change in accrual resulting from the implementation of new rates	18
Other	(2)
Total IPL Increase	**52**
Total US SBU Operating Margin Decrease	**$ (39)**

Adjusted Operating Margin decreased $85 million due to the drivers above, adjusted for NCI and excluding unrealized gains and losses on derivatives.

Adjusted PTC decreased $13 million driven by the decrease of $85 million in Adjusted Operating Margin described above, partially offset by a gain on contract termination at DP&L, lower interest expense at DPL and IPL in part due to the sell-down impacts and the impact of HLBV at our Distributed Energy business as a result of new projects achieving COD in 2016.

Free Cash Flow increased $55 million, of which $32 million was attributable to NCI. The increase was driven by changes in net cash provided by operating activities comprising:

- A decrease of $21 million in Operating Margin (net of $28 million in increased depreciation and $10 million in other non-cash impacts);
- Decrease in working capital of $169 million primarily driven by a $142 million reduction in inventory holdings as we focused on inventory optimization efforts and reductions in working capital needs of $17 million resulting from the sale of MC^2 and DPLER; and
- Increases in working capital of $97 million primarily related to an increase in receivables of $80 million resulting from higher rates at IPL and favorable weather in Q4 2016.

Free Cash was also impacted by a $12 million increase in maintenance capital expenditures due to higher expenditures at IPL. Free Cash Flow was also impacted by lower interest payments of $16 million due to debt repayments at DPL and lower interest rates.

ANDES SBU

The following table summarizes Operating Margin, Adjusted Operating Margin, Adjusted PTC, and Free Cash Flow (in millions) for the periods indicated:

For the Years Ended December 31,	2017	2016	2015	$ Change 2017 vs. 2016	% Change 2017 vs. 2016	$ Change 2016 vs. 2015	% Change 2016 vs. 2015
Operating Margin	$ 658	$ 634	$ 618	$ 24	4%	$ 16	3%
Adjusted Operating Margin	450	442	466	8	2%	(24)	-5%
Adjusted PTC	386	390	482	(4)	-1%	(92)	-19%
Operating Cash Flow	714	475	462	239	50%	13	3%
Free Cash Flow	620	383	343	237	62%	40	12%
Free Cash Flow Attributable to NCI	204	119	119	85	71%	—	—%

(1) See Item 1.—*Business* for the respective ownership interest for key businesses. In addition, AES owned 71% of Gener and Chivor prior to sell down effective December 2015 which resulted in ownership of 67%. The Alto Maipo (under construction) and Cochrane plants are owned 62% and 40% respectively.

Fiscal year 2017 versus 2016

Including the favorable impact of foreign currency translation and remeasurement of $19 million, Operating Margin increased $24 million, or 4%, which was driven primarily by the following (in millions):

Gener		
Negative impact of new regulation on Emissions (Green Taxes)	$	(41)
Lower availability of efficient generation resulting in higher replacement energy and fixed costs mainly associated with major maintenance at Ventanas Complex		(29)
Lower margin at the SING market primarily associated with lower contract sales and increase in coal prices at Norgener partially offset by higher spot sales		(21)
Start of operations at Cochrane Units I and II in July and October 2016, respectively		72
Other		1
Total Gener Decrease		**(18)**
Argentina		
Higher capacity payments primarily associated to changes in regulation in 2017		64
Lower generation at CTSN mainly associated with lower demand		(26)
Higher fixed costs mainly associated with higher people costs driven by inflation		(11)
Favorable FX impact		9
Total Argentina Increase		**36**
Chivor		
Higher contract sales primarily associated to an increase in contracted capacity at higher prices		35
Lower spot sales mainly associated to lower generation and lower spot prices		(37)
Other		8
Total Chivor Increase		**6**
Total Andes SBU Operating Margin Increase	**$**	**24**

Adjusted Operating Margin increased $8 million due to the drivers above, adjusted for NCI and excluding restructuring charges.

Adjusted PTC decreased $4 million, driven by higher interest expense, mainly due to the issuance of debt at Argentina and lower interest capitalization in Cochrane and Chivor, and the write-off of water rights at Gener resulting from a business development project that is no longer pursued. These negative impacts were partially offset by the increase in Adjusted Operating Margin, foreign currency gains in Argentina associated with the collection of financing receivables, prepayment of financial debt denominated in U.S. dollars in 2017, and lower foreign currency losses associated with the sale of Argentina's sovereign bonds at Termoandes.

Free Cash Flow increased $237 million, of which $85 million was attributable to NCI. The increase was driven by changes in net cash provided by operating activities comprising:

- $98 million increase in Operating Margin (net of higher depreciation of $33 million and $41 million of environmental tax accruals in Chile impacting margin, but not free cash flow);
- Decreases in working capital of $130 million primarily driven by higher VAT Refunds of $60 million at Alto Maipo and other Construction Projects and $38 million in collections of financing receivables related to the commencement of operations of Guillermo Brown and Cochrane; and
- Increases in working capital of $55 million primarily related to $40 million in lower collections of receivables at Chivor.

Free Cash Flow was also impacted by a net increase of $64 million in other drivers, primarily related to a $58 million decrease in taxes and $34 million in dividends received from Guacolda, partially offset by a $27 million increase in interest payments.

Fiscal year 2016 versus 2015

Including the unfavorable impact of foreign currency translation and remeasurement of $36 million, Operating Margin increased $16 million, or 3%, which was driven primarily by the following (in millions):

Gener	
Lower spot prices on energy and fuel purchases	$ 82
Start of operations of Cochrane Plant	36
Other	(3)
Total Gener Increase	**115**
Argentina	
Higher rates driven by annual price review granted by Resolution 22/2016	61
Lower availability mainly associated with planned major maintenance	(20)
Higher fixed costs primarily driven by higher inflation and by higher maintenance cost	(44)
Unfavorable FX remeasurement impacts	(21)
Total Argentina Decrease	**(24)**
Chivor	
Higher volume of energy sales to Spot Market	14
Unfavorable FX remeasurement impacts	(15)
Lower spot sales prices	(72)
Other	(2)
Total Chivor Decrease	**(75)**
Total Andes SBU Operating Margin Increase	**$ 16**

Adjusted Operating Margin decreased $24 million due to the drivers above, adjusted for NCI.

Adjusted PTC decreased $92 million driven by the decrease in Equity Earnings of $54 million mainly related to Guacolda's reorganization in September 2015, the decrease of $24 million in Adjusted Operating Margin and the increase of $12 million in interest expense primarily associated with lower interest capitalization after the beginning of commercial operations at Cochrane.

Free Cash Flow increased $40 million, none of which was attributable to NCI. The increase was driven by changes in net cash provided by operating activities comprising:

- An increase of $58 million in Operating Margin (net of $42 million in increased depreciation and other non-cash impacts);
- Decrease in working capital of $178 million, primarily driven by $83 million in higher collections at Chivor related to Q4 2015 sales, a $38 million positive impact related to a one-time interest rate swap termination payment at Ventanas in July 2015, and $57 million in collections of financing receivables and maintenance remuneration from CAMMESSA in Argentina; and
- Increases in working capital of $137 million primarily related to an increase in VAT accruals of $107 million related to our Cochrane and Alto Maipo construction projects.

Free Cash Flow was also impacted by a $57 million increase in taxes at Chile and Chivor, a $29 million increase in interest payments at Gener due to new unsecured notes issued in July 2015 as part of the Ventanas refinancing, and a $27 million reduction in maintenance and non-recoverable capital expenditures due to lower expenditures on emissions and control equipment at Chile.

BRAZIL SBU

The following table summarizes Operating Margin, Adjusted Operating Margin, Adjusted PTC, and Free Cash Flow (in millions) for the periods indicated:

For the Years Ended December 31,	2017	2016	2015	$ Change 2017 vs. 2016	% Change 2017 vs. 2016	$ Change 2016 vs. 2015	% Change 2016 vs. 2015
Operating Margin	$ 203	$ 186	$ 397	$ 17	9 %	$ (211)	-53%
Adjusted Operating Margin	48	41	97	7	17 %	(56)	-58%
Adjusted PTC	60	38	92	22	58 %	(54)	-59%
Operating Cash Flow	469	716	136	(247)	(34)%	580	NM
Free Cash Flow	279	532	(24)	(253)	(48)%	556	NM
Free Cash Flow Attributable to NCI	204	422	5	(218)	(52)%	417	NM

(1) See Item 1.—*Business* for the respective ownership interest for key businesses.

Fiscal year 2017 versus 2016

Including the favorable impact of foreign currency translation of $19 million, Operating Margin increased $17 million, or 9%, which was driven primarily by the following (in millions):

Tietê	
Net impact of volume and prices of bilateral contracts due to higher energy purchased	$ (100)
Net impact of volume and prices of lower energy purchased in spot market	71
Higher volume due to acquisition of new wind entities - Alto Sertão II	23
Favorable FX impacts	21
Other	4
Total Tietê Increase	**19**
Other Business Drivers	**(2)**
Total Brazil SBU Operating Margin Increase	**$ 17**

Adjusted Operating Margin increased $7 million due to the drivers above, adjusted for NCI and excluding costs due to dispositions and acquisitions of business interests.

Adjusted PTC increased $22 million, driven by a $28 million increase from the settlement of a legal dispute with YPF at Uruguaiana as well as the $7 million of increase in Adjusted Operating Margin described above, partially offset by $5 million of higher interest expense over Alto Sertão II debt.

Free Cash Flow decreased $253 million, of which $218 million was attributable to NCI. The decrease was driven by changes in net cash provided by operating activities comprising:

- $35 million increase in Operating Margin (net of increased depreciation of $18 million);
- $58 million decrease due to the sale of Sul in October 2016;
- Increases in working capital of $913 million, primarily related to $600 million of higher costs deferred in net regulatory assets at Eletropaulo resulting from unfavorable hydrology in prior periods and $198 million of lower collections of energy sales at Eletropaulo due to higher tariff flags in 2016; and
- Decreases in working capital of $445 million, primarily due to $411 million related to timing of payments for energy purchases due to lower energy costs and lower regulatory charges at Eletropaulo and Tietê.

Free Cash Flow was also impacted by an increase of $240 million in other drivers, primarily related to $93 million of lower tax payments at Tietê and Eletropaulo, $71 million in lower interest paid at Tietê and Eletropaulo, and $60 million collected from a legal dispute settlement with YPF at Uruguaiana.

Fiscal year 2016 versus 2015

Including the unfavorable impact of foreign currency translation of $14 million, Operating Margin decreased $211 million, or 53%, which was driven primarily by the following (in millions):

Tietê	
Lower rates for energy sold under new contracts	$ (239)
Unfavorable FX impacts	(14)
Higher fixed costs due to higher legal settlements	(13)
Lower rates for energy purchases mainly due to decrease in spot market prices	78
Other	(2)
Total Tietê Decrease	**(190)**
Uruguaiana	
Operations in 2015 compared to not operating in 2016	(20)
Total Uruguaiana Decrease	**(20)**
Other Business Drivers	**(1)**
Total Brazil SBU Operating Margin Decrease	**$ (211)**

Adjusted Operating Margin decreased $56 million due to the drivers above, adjusted for NCI and excluding unrealized gains and losses on derivatives.

Adjusted PTC decreased $54 million, driven by the decrease of $56 million in Adjusted Operating Margin described above.

Free Cash Flow increased $556 million, of which $417 million was attributable to NCI. The increase was driven by changes in net cash provided by operating activities comprising:

- $308 million decrease in Operating Margin (net of $45 million in non-cash impacts, primarily due to the reversal of a contingent regulatory liability at Eletropaulo in 2015);

- Decreases in working capital of $1.5 billion, primarily due to $974 million in higher collections of costs deferred in net regulatory assets at Eletropaulo and Sul resulting from unfavorable hydrology in 2015 and $416 million of higher collections on energy sales in 2016; and
- Increases in working capital of $623 million primarily due to $581 million related to regulatory charges and timing of payments for energy purchases at Eletropaulo and Sul in 2016.

MCAC SBU

The following table summarizes Operating Margin, Adjusted Operating Margin, Adjusted PTC, and Free Cash Flow (in millions) for the periods indicated:

For the Years Ended December 31,	2017	2016	2015	$ Change 2017 vs. 2016	% Change 2017 vs. 2016	$ Change 2016 vs. 2015	% Change 2016 vs. 2015
Operating Margin	$ 589	$ 523	$ 543	$ 66	13%	$ (20)	-4%
Adjusted Operating Margin	470	413	438	57	14%	(25)	-6%
Adjusted PTC	340	267	327	73	27%	(60)	-18%
Operating Cash Flow	427	312	705	115	37%	(393)	-56%
Free Cash Flow	345	219	625	126	58%	(406)	-65%
Free Cash Flow Attributable to NCI	61	51	127	10	20%	(76)	-60%

(1) See Item 1.—*Business* for the respective ownership interest for key businesses. AES owned 92% of Andres and Los Mina and 46% of Itabo in the Dominican Republic until December 2015 when the ownership changed to 90% at Andres and Los Mina and 45% at Itabo until October 2017.

Fiscal year 2017 versus 2016

Operating Margin increased $66 million, or 13%, which was driven primarily by the following (in millions):

Dominican Republic	
Higher contracted energy sales net of LNG fuel consumption mainly driven by Los Mina combined cycle commencement of operations in June 2017	$ 34
Other	6
Total Dominican Republic Increase	**40**
Mexico	
Higher availability as a result of a plant forced maintenance in 2016	13
Other	7
Total Mexico Increase	**20**
Other Business Drivers	**6**
Total MCAC SBU Operating Margin Increase	**$ 66**

Adjusted Operating Margin increased $57 million due to the drivers above, adjusted for NCI and excluding unrealized gains and losses on derivatives and one-time restructuring charges.

Adjusted PTC increased $73 million, driven by the increase in Adjusted Operating Margin of $57 million as described above.

Free Cash Flow increased $126 million, of which $10 million was attributable to NCI. The increase was driven by changes in net cash provided by operating activities comprising:

- $73 million increase in Operating Margin (net of higher depreciation of $7 million);
- Decreases in working capital in Dominican Republic of $61 million primarily due to the collection of past overdue amounts as part of the sale of receivables executed with the distribution companies and CDEEE in 2017; and
- Increases in working capital in Puerto Rico of $10 million primarily related to lower payments and collections caused by Hurricane Maria.

Free Cash Flow was also impacted by lower tax payments of $17 million in El Salvador and a $10 million decrease in maintenance and non-recoverable environmental capital expenditures, partially offset by higher interest payments in Dominican Republic of $25 million due to the issuance of new Senior Notes in Los Mina.

Fiscal year 2016 versus 2015

Operating Margin decreased $20 million, or 4%, which was driven primarily by the following (in millions):

Mexico	
Lower availability and related costs	$ (11)
Other	(6)
Total Mexico Decrease	**(17)**
El Salvador	
Higher fixed costs and lower energy sales margin	(10)
Total El Salvador Decrease	**(10)**
Panama	
Expenses related to the ongoing construction of a natural gas generation plant and a liquefied natural gas terminal	(19)
Commencement of power barge operations at the end of March 2015	13
Other	(3)
Total Panama Decrease	**(9)**
Dominican Republic	
Higher contracted and spot energy sales	24
Total Dominican Republic Increase	**24**
Other Business Drivers	**(8)**
Total MCAC SBU Operating Margin Decrease	**$ (20)**

Adjusted Operating Margin decreased $25 million due to the drivers above, adjusted for NCI and excluding unrealized gains and losses on derivatives.

Adjusted PTC decreased $60 million, driven by the decrease in Adjusted Operating Margin of $25 million described above as well as a 2015 compensation agreement regarding early termination of the original Barge PPA of $10 million and a $26 million allowance recognized in 2016 at Puerto Rico.

Free Cash Flow decreased $406 million, of which $76 million was attributable to NCI. The decrease was driven by changes in net cash provided by operating activities comprising:

- A decrease of $10 million in Operating Margin (net of $10 million in depreciation); and
- Increases in working capital of $338 million, primarily related to higher accounts receivable balances for the Dominican Republic of $243 million due to collections of overdue receivables in September 2015 and for Puerto Rico of $47 million primarily due to lower sales in Q4 2015.

Free Cash Flow was also impacted by a $13 million increase in maintenance and non-recoverable environmental capital expenditures.

EURASIA SBU

The following table summarizes Operating Margin, Adjusted Operating Margin, Adjusted PTC, and Free Cash Flow (in millions) for the periods indicated:

For the Years Ended December 31,	2017	2016	2015	$ Change 2017 vs. 2016	% Change 2017 vs. 2016	$ Change 2016 vs. 2015	% Change 2016 vs. 2015
Operating Margin	$ 423	$ 429	$ 452	$ (6)	-1%	$ (23)	-5%
Adjusted Operating Margin	308	305	346	3	1%	(41)	-12%
Adjusted PTC	290	283	331	7	2%	(48)	-15%
Operating Cash Flow	610	892	354	(282)	-32%	538	NM
Free Cash Flow	586	865	437	(279)	-32%	428	98%
Free Cash Flow Attributable to NCI	173	177	112	(4)	-2%	65	58%

(1) See Item 1.—*Business* for the respective ownership interest for key businesses.

Fiscal year 2017 versus 2016

Operating Margin decreased $6 million, or 1%, and Adjusted Operating Margin increased $3 million, or 1%, with no material drivers.

Adjusted PTC increased $7 million, primarily driven by the increase of in Adjusted Operating Margin, adjusted for NCI and excluding unrealized gains and losses on derivatives.

Free Cash Flow decreased $279 million, of which $4 million was attributable to NCI. The decrease was primarily driven by changes in net cash provided by operating activities, specifically:

- A decrease of $28 million in Operating Margin (net of $22 million in decreased depreciation);

- A reduction in cash receipts of $362 million, primarily attributable to a $360 million payment made in April 2016 from NEK, net of payments to the fuel supplier, for Maritza related to overdue receivables; and
- Decreases in working capital of $64 million primarily related to lower working capital requirements of $50 million at Masinloc and Mong Duong due to the timing of payments for coal purchases.

Free Cash Flow was also impacted by a $25 million reduction in maintenance and non-recoverable environmental capital expenditures and a $20 million decrease in interest payments.

Fiscal year 2016 versus 2015

Including the unfavorable impact of foreign currency translation of $36 million, Operating Margin decreased $23 million, or 5%, which was driven primarily by the following (in millions):

Kazakhstan	
Unfavorable FX impact due to KZT depreciation against USD	$ (29)
Other	(1)
Total Kazakhstan Decrease	**(30)**
Maritza	
Lower contracted capacity prices due to PPA amendment	(18)
Other	(2)
Total Maritza Decrease	**(20)**
Ballylumford	
Higher contracted revenues	27
Lower plant capacity resulting from the retirement of one generation facility	(21)
Total Ballylumford Increase	**6**
Mong Duong	
Impact of full year operations for 2016 compared to commencement of principal operations in April 2015	16
Total Mong Duong Increase	**16**
Other Business Drivers	**5**
Total Eurasia SBU Operating Margin Decrease	**$ (23)**

Adjusted Operating Margin decreased $41 million due to the drivers above, adjusted for NCI and excluding unrealized gains and losses on derivatives.

Adjusted PTC decreased $48 million, driven by the decrease of $41 million in Adjusted Operating Margin described above, lower equity earnings at OPGC in India due to lower tariffs and the net impact of higher interest expense and higher interest income at Mong Duong.

Free Cash Flow increased $428 million, of which $65 million was attributable to NCI. The increase was driven by a $26 million reduction in maintenance and non-recoverable environmental capital expenditures and changes in net cash provided by operating activities comprising:

- A decrease of $43 million in Operating Margin (net of $20 million in decreased depreciation and other non-cash impacts);
- Increases in working capital of $472 million from increased collections of $360 million at Maritza from NEK, net of payments to the fuel supplier, and a reduction in working capital requirements of $58 million at Mong Duong due to higher working capital needs in 2015 in preparation for commencement of plant operations; and
- Decreases in working capital of $47 million attributable to a $24 million decrease in CO_2 allowances due to a price decrease at Maritza and a higher interest expense of $34 million as capitalization of interest ceased upon COD of Mong Duong in 2015.

Key Trends and Uncertainties

During 2018 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 impact 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.

Macroeconomic and Political

The political environments in some countries where our subsidiaries conduct business have changed during

2017. 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.

United States Tax Law Reform

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act (the “2017 Act”). The legislation significantly revised the U.S. corporate income tax system by, among other things, lowering the corporate income tax rate, introducing new limitations on interest expense deductions, subjecting foreign earnings in excess of an allowable return to current U.S. taxation, and adopting a semi-territorial corporate tax system. These changes will materially impact our effective tax rate in future periods. Furthermore, we anticipate that higher U.S. tax expense may fully utilize our remaining net operating loss carryforwards in the near term, which could lead to material cash tax payments in the United States. Specific provisions of the 2017 Act and their potential impacts on the Company are noted below. Our interpretation of the 2017 Act may change as the U.S. Treasury and the Internal Revenue Service issue additional guidance. Such changes may be material.

Lower Tax Rate — The corporate tax rate decreased from 35 percent to 21 percent beginning in 2018. In addition to deferred tax remeasurement impacts, the lower tax rate will result in the recognition, at December 31, 2017, of a regulatory liability at IPL and DPL. The regulatory liability will reflect deferred taxes that will flow back to ratepayers over time.

Limitation on Interest Expense Deductions — The 2017 Act introduced a new limitation on the deductibility of net interest expense beginning January 1, 2018. The deduction will be limited to interest income, plus 30 percent of tax basis EBITDA through 2021 (30 percent of EBIT beginning January 1, 2022). This determination is made at the consolidated group level, although it applies separately to partnerships. The limitation does not apply to interest expense attributable to regulated utility property. The U.S. Treasury and Internal Revenue Service are expected to provide guidance to clarify how the exception will apply to regulated utility holding companies. Given typical project financing and current U.S. holding company debt levels, we anticipate that this limitation will materially, negatively impact our effective tax rate.

Cost Recovery — The 2017 Act amended depreciation rules to provide full expensing (100% bonus depreciation) for assets that commence construction and are placed in service before January 1, 2023. This provision is phased down by 20 percent ratably through 2027. The immediate full expensing provision is elective, but it does not apply to regulated utility property. This change is not expected to impact the Company’s effective tax rate; however, if elected, it could impact taxable income and cash taxes in future periods.

Transition to a Participation Exemption System — A transition tax will be imposed on previously untaxed, deferred foreign earnings at a rate of either 8 percent or 15.5 percent, depending on the liquidity of the underlying foreign earnings. Prospectively, a 100 percent dividends received deduction will apply to foreign source dividends upon repatriation.

Global Intangible Low Taxed Income (“GILTI”) — A new provision in the U.S. tax law subjects the foreign earnings of foreign subsidiaries to current U.S. taxation to the extent that those earnings exceed an allowable economic return on investment. The allowable return is 10 percent of the adjusted tax basis in the foreign subsidiaries’ tangible property, reduced by interest expense. The foreign earnings subject to current taxation under the GILTI provision are not limited to those derived from intangible property and may include gains derived from some future asset sales. Although the new GILTI rules provide for a reduced 10.5 percent effective tax rate on captured income (increasing to 13.125% January 1, 2026), by way of a 50 percent deduction, companies with a 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.

We expect that the GILTI provision may capture a very significant portion of our foreign earnings and subject those foreign earnings to current U.S. taxation. As a result, we expect the GILTI provision to materially, negatively impact our effective tax rate. Prospectively, the consequences of the new GILTI provision may be mitigated by foreign tax credits. However, additional guidance from the U.S. Treasury and Internal Revenue Service will be required to determine the extent to which the Company will be able to claim such foreign tax credits and mitigate the negative consequences of the GILTI provision.

State Taxes — The reactions of the individual states to federal tax reform are still evolving. Most states will assess whether and how the federal changes will be incorporated into their state tax legislation. As we expect higher taxable income in the future due to the federal changes, this may also lead to higher state taxable income. Our current state tax provisions predominantly have full valuation allowances against state net operating losses. These positions will be re-assessed in the future as state tax law evolves and may result in material changes in position.

Tax Equity Structures — Our U.S. renewable energy portfolio operates primarily through tax equity partnerships. We cannot be certain of the impacts U.S. tax reform may have on availability or pricing of tax equity for future growth opportunities. Impacts of provisions such as the lower tax rate and immediate expensing may impact the amount and timing of returns allocable to our partners in our existing tax equity structures.

SAB 118 — As further explained in Note 20—*Income Taxes* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K we have included certain reasonable estimates of the impact of U.S. tax law reform subject to potential adjustments in future periods.

Puerto Rico — Our subsidiaries in Puerto Rico have long-term PPAs with state-owned PREPA, which has been facing economic challenges that could impact the Company.

In order to address these challenges, on June 30, 2016, the Puerto Rico Oversight, Management, and Economic Stability Act ("PROMESA") was signed into law. PROMESA created a structure for exercising federal oversight over the fiscal affairs of U.S. territories and allowed for the establishment of an Oversight Board with broad powers of budgetary and financial control over Puerto Rico. PROMESA also created procedures for adjusting debts accumulated by the Puerto Rico government and, potentially, other territories ("Title III"). Finally, PROMESA expedites the approval of key energy projects and other critical projects in Puerto Rico.

PREPA entered into preliminary Restructuring Support Agreements ("RSAs") with their lenders. Under PROMESA, PREPA submitted the RSA to the Oversight Board for approval on April 28, 2017, which the board denied on June 28, 2017. As a consequence, on July 2, 2017, the Oversight Board filed for bankruptcy on behalf of PREPA under Title III.

As a result of the bankruptcy filing, AES Puerto Rico and AES Ilumina's non-recourse debt of $365 million and $36 million, respectively, are in default and have been classified as current as of December 31, 2017.

Additionally, on July 18, 2017, Moody's downgraded AES Puerto Rico to Caa1 from B3 due to the heightened default risk for AES Puerto Rico as a result of PREPA's bankruptcy protection. This protection gives PREPA the ability to renegotiate contracts, which could impact the value of our assets in Puerto Rico or otherwise have a material impact on the Company. In this regard, PREPA had requested the Company to renegotiate its 24 MW AES Ilumina's PPA. After the event of the Hurricanes Maria and Irma, these negotiations were put on hold.

In September 2017, Puerto Rico and the U.S. Virgin Islands were severely impacted by Hurricanes Irma and Maria, disrupting the operations of AES Puerto Rico, AES Ilumina, and certain Distributed Energy assets. The Company sustained modest damage to its 24 MW AES Ilumina solar plant, resulting in a $2 million loss, and minor damage to its 524 MW AES Puerto Rico thermal plants, both located in Puerto Rico.

As a result of the hurricanes, PREPA has declared an event of Force Majeure. However, both units of AES Puerto Rico and approximately 75% of AES Ilumina have been available to generate electricity since mid-October which, in accordance with the PPAs, will allow AES Puerto Rico to invoice capacity, even under Force Majeure. Puerto Rico's infrastructure was severely damaged, including electric infrastructure and transmission lines. The extensive structural damage caused by hurricane winds and flooding is expected to take significant time and cost to repair.

Due to the extensive damage from the hurricanes, energy demand in Puerto Rico has decreased and is expected to remain low until economic activity has recovered. Despite the decrease in demand, AES Puerto Rico has resumed generation and continues to be the lowest cost and EPA compliant energy provider in Puerto Rico. Therefore, we expect AES Puerto Rico to continue to be a critical supplier to PREPA.

On October 24, 2017, the U.S. Congress approved a $37 billion emergency disaster relief bill which will allow the U.S. Government to help victims from the hurricanes and assist with the infrastructure rebuild in the affected areas through the Federal Emergency Management Agency. This supplemental appropriation includes an allocation of $5 billion for the Disaster Assistance Direct Loan Program to assist local governments, like Puerto Rico, in providing essential services, such as reestablishing electricity.

In November 2017, AES Puerto Rico signed a Forbearance and Standstill Agreement with its lenders to prevent the lenders from taking any action against the company due to the default events. This agreement will expire on March 22, 2018.

The Company's receivable balances in Puerto Rico as of December 31, 2017 totaled $86 million, of which $53 million was overdue. Despite the disruption caused by the hurricanes and the Title III protection, PREPA has restarted the payments to the generators. AES Puerto Rico has been able to collect $28 million of overdue amounts as of December 31, 2017.

In January 2018, Puerto Rico announced its intention to privatize PREPA. The plan will need to be approved by the Oversight Board, and, if approved, could take 18 months to complete. It is difficult to predict the outcome of the proposed privatization, but the impact on our businesses in Puerto Rico and AES could be material.

Considering the information available as of the filing date, Management believes the carrying amount of our assets in Puerto Rico of $627 million is recoverable and no reserve on the receivables is necessary as of December 31, 2017.

Brazil — Brazilian President Michael Temer continues to seek economic reforms that would improve the economic outlook in Brazil, which may benefit our businesses in the country. Corruption investigations and the 2018 presidential campaign have limited Mr. Temer's ability to implement these reforms. Despite these limitations, the Brazilian economy is showing moderate signs of improvement.

United Kingdom — In June 2016, the United Kingdom ("U.K.") held a referendum in which voters approved an exit from the European Union ("E.U."), commonly referred to as "Brexit." In December 2017, the U.K. and E.U. agreed terms to conclude Phase 1 negotiations and have moved into Phase 2 of negotiations with respect to long-term trading relationship and a potential transitional period. The U.K. is expected to exit the E.U. on March 29, 2019. While the full impact of the Brexit remains uncertain, these changes may adversely affect our operations and financial results.

Regulatory

International Trade Commission — In September 2017, the U.S. International Trade Commission ("ITC") determined that serious injury has been caused by foreign solar photovoltaic panels to U.S. manufacturers. The ITC proposed recommendations for remedies that include tariffs at various levels, a quota system and licensing fees. In January 2018, the U.S. President approved tariffs of 30% in the first year, which will gradually decrease to 15% over four years. AES is evaluating the impact of these tariffs, but they will likely increase the cost of solar photovoltaic panels in the short term. The Company has taken mitigating action to limit our exposure to these increased costs, such as acquiring solar panels for committed projects in 2017 in anticipation of the new tariff, however these tariffs may impact the economics of future solar development projects in the U.S., including those of our solar businesses.

Maritza PPA Review — The DG Comp continues to review whether Maritza's PPA with NEK is compliant with the European Commission's state aid rules. Although no formal investigation has been launched by DG Comp to date, Maritza has engaged in discussions with the DG Comp case team and representatives of Bulgaria to discuss the agency's review. In the near term, Maritza expects that it will engage in discussions with Bulgaria to attempt to reach a negotiated resolution concerning DG Comp's review. The anticipated discussions could involve a range of potential outcomes, including but not limited to termination of the PPA and payment of some level of compensation to Maritza. Any negotiated resolution would be subject to mutually acceptable terms, lender consent, and DG Comp approval. At this time, we cannot predict the outcome of the anticipated discussions between Maritza and Bulgaria, nor can we predict how DG Comp might resolve its review if the discussions fail to result in an agreement concerning the review. 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 assurances that this matter will be resolved favorably; if it is not, there could be a material adverse impact on Maritza's and the Company's respective financial statements.

Alto Maipo

Alto Maipo has experienced construction difficulties which have resulted in increased projected costs over the original $2 billion budget. These overages led to a series of negotiations with the intention of restructuring the project's existing financial structure and obtaining additional funding. On March 17, 2017, AES Gener completed a legal and financial restructuring of Alto Maipo. As a part of this restructuring, AES Gener simultaneously acquired a 40% ownership interest from Minera Los Pelambres ("MLP"), a noncontrolling shareholder, for nominal consideration, and sold a 6.7% ownership interest to Strabag, one of the construction contractors. Through its 67% ownership interest in AES Gener, the Company now has an effective 62% indirect economic interest in Alto Maipo. Additionally, certain construction milestones were amended and if Alto Maipo is unable to meet these milestones, there could be a material impact to the financing and value of the project. For additional information on risks regarding construction and development, refer to Item 1A.—*Risk Factors—Our Business is Subject to Substantial Development Uncertainties* of this Form 10-K.

Following the restructuring, the project continued to face construction difficulties, including greater than expected costs and slower than anticipated productivity by construction contractors towards agreed-upon milestones. As a result of the failure to perform by one of its construction contractors, Constructora Nuevo Maipo S.A. (“CNM”), Alto Maipo terminated CNM’s contract during the second quarter of 2017. As a result of the termination of CNM, Alto Maipo’s construction debt of $618 million and derivative liabilities of $132 million are in technical default and presented as current on the balance sheet as of December 31, 2017.

Alto Maipo is currently a party to arbitration concerning the termination of CNM and other related matters. These include Alto Maipo’s draws on letters of credit securing CNM’s performance under the parties’ construction contract totaling $73 million (the “LC Funds”). The LC Funds were collected by Alto Maipo and are available to be utilized for on-going construction costs. In February 2018, CNM was denied their request for interim relief to recover the LC Funds. However, the overall arbitration concerning the termination of CNM, including a final ruling on CNM’s claim to recover the LC Funds, is still pending. Alto Maipo cannot predict the ultimate outcome of the arbitration or any related proceedings. For more information on the legal proceedings concerning CNM, see Item 3.—*Legal Proceedings* of this Form 10-K.

Construction at the project is continuing, and the project is over 61% complete. In February 2018, Alto Maipo signed an amended EPC contract with Strabag, the permanent replacement contractor selected to complete CNM’s work, subject to approval by the project's senior lenders as part of the second refinancing. Alto Maipo is working to resolve the challenges described above, however, there can be no assurance that Alto Maipo will succeed in these efforts and if there are further delays or cost overruns, or if Alto Maipo is unable to reach an agreement with the non-recourse lenders, there is a risk these lenders may seek to exercise remedies available as a result of the default noted above, or Alto Maipo may not be able to meet its contractual or other obligations and may be unable to continue with the project. If any of the above occur, there could be a material impairment for the Company.

The carrying value of long-lived assets and deferred tax assets of Alto Maipo as of December 31, 2017 was approximately $1.4 billion and $60 million, respectively. Through its 67% ownership interest in AES Gener, the Parent Company has invested approximately $375 million in Alto Maipo and has an additional equity funding commitment of $39 million required as part of the March 2017 restructuring described above. AES Gener may provide material additional funding commitments as part of ongoing negotiations and future project restructurings. Even though certain construction difficulties have not been formally resolved, construction costs continue to be capitalized as management believes the project is probable of completion. Management believes the carrying value of the long-lived asset group is recoverable and was not impaired as of December 31, 2017. In addition, management believes it is more likely than not the deferred tax assets will be realized; however, they could be reduced if estimates of future taxable income are decreased.

Changuinola Tunnel Leak

Increased water levels were noted in a creek near the Changuinola power plant, a 223 MW hydroelectric power facility in Panama. After the completion of an assessment, the Company has confirmed loss of water in specific sections of the tunnel. The plant is in operation and can generate up to its maximum capacity. Repairs will be needed to ensure the long term performance of the facility, during which time the affected units of the plant will be out of service. Subject to final inspection, the repairs may take up to 10 months to complete and are expected to commence during the first quarter of 2019. The Company has notified its insurers of a potential claim and has asserted claims against its construction contractor. However, there can be no assurance of collection. The Company continues to monitor the situation to identify any potential changes to the tunnel. The Company has not identified any indicators of impairment and believes the carrying value of the long-lived asset group is recoverable as of December 31, 2017.

Impairments

Long-lived Assets **—** During the year ended December 31, 2017, the Company recognized asset impairment expense of $186 million at the Kazakhstan CHP and Hydroelectric plants, $175 million at DPL, $121 million at Laurel Mountain, $37 million at Kilroot, and $18 million at other businesses in the PJM market. See Note 19—*Asset Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information. After recognizing these asset impairment expenses, the carrying value of the long-lived asset groups, including those that were assessed and not impaired, excluding Alto Maipo, totaled $1 billion at December 31, 2017.

Events or changes in circumstances that may necessitate further recoverability tests and potential impairment 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, or an expectation that it is more likely than not that the asset will be disposed of before the end of its previously estimated useful life.

Goodwill **—** The Company currently has no reporting units considered to be "at risk." A reporting unit is considered "at risk" when its fair value is not higher than its carrying amount by 10%. The Company monitors its reporting units at risk of Step 1 failure on an ongoing basis. It is possible that the Company may incur goodwill impairment charges at any reporting units containing goodwill in future periods if adverse changes in their business or operating environments occur. See Note 8—*Goodwill and Other Intangible Assets* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Functional Currency

Argentina — In February 2017, the Argentina Ministry of Energy issued Resolution 19/2017, which established changes to the energy price framework. As a result of this resolution, tariffs are now priced in USD rather than Argentine pesos, and the retention of unpaid amounts and accumulation of receivables with CAMMESA was eliminated. Concurrent with the establishment of the new price framework, AES Argentina issued $300 million of bonds denominated in USD. Given these significant changes in economic facts and circumstances, the Company changed the functional currency of the Argentina businesses from the Argentine peso to the USD effective February 2017. Changes to the energy framework could have a material impact on the Company.

Chivor — In May 2017, the Company repaid its outstanding USD denominated debt held at Chivor. In addition, the Company updated Chivor's future financing strategy to align with Colombian peso denominated operational cash flows of the business. Given these changes, the Colombian peso is now regarded as the currency of the economic environment in which Chivor primarily operates. Therefore, the Company changed the functional currency of the Chivor business from USD to the Colombian peso effective May 2017.

Capital Resources and Liquidity

Overview — As of December 31, 2017, the Company had unrestricted cash and cash equivalents of $949 million, of which $11 million was held at the Parent Company and qualified holding companies. The Company also had $424 million in short term investments, held primarily at subsidiaries. In addition, we had restricted cash and debt service reserves of $839 million. The Company also had non-recourse and recourse aggregate principal amounts of debt outstanding of $15.3 billion and $4.6 billion, respectively. Of the approximately $2.2 billion of our current non-recourse debt, $1.1 billion was presented as such because it is due in the next twelve months and $1 billion relates to debt considered in default due to covenant violations. Defaults at AES Puerto Rico are covenant and payment defaults, for which Forbearance and Standstill Agreements have been signed. All other defaults are not payment defaults, but are instead technical defaults triggered by failure to comply with other covenants and/or other conditions such as (but not limited to) failure to meet information covenants, complete construction or other milestones in an allocated time, meet certain minimum or maximum financial ratios, or other requirements contained in the non-recourse debt documents of the Company.

We expect such current maturities will be repaid from net cash provided by operating activities of the subsidiary to which the debt relates or through opportunistic refinancing activity or some combination thereof. We have $5 million of recourse debt which matures within the next twelve months. 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. Generally, a portion or all of the variable rate debt is fixed through the use of interest rate swaps. In addition, the debt is typically denominated in the currency that matches the currency of the revenue expected to be generated from the benefiting project, thereby reducing currency risk. In certain cases, the currency is matched through the use of derivative instruments. The majority of our non-recourse debt is funded by international commercial banks, with debt capacity supplemented by multilaterals and local regional banks.

Given our long-term debt obligations, the Company is subject to interest rate risk on debt balances that accrue interest at variable rates. When possible, the Company will borrow funds at fixed interest rates or hedge its variable rate debt to fix its interest costs on such obligations. In addition, the Company has historically tried to maintain at least 70% of its consolidated long-term obligations at fixed interest rates, including fixing the interest rate through the use of interest rate swaps. These efforts apply to the notional amount of the swaps compared to the amount of related underlying debt. Presently, the Parent Company's only material unhedged exposure to variable interest rate debt relates to indebtedness under its $521 million outstanding secured term loan due 2022 and drawings of $207 million under its secured credit facility. On a consolidated basis, of the Company's $20 billion of total debt outstanding as of December 31, 2017, approximately $3.2 billion bore interest at variable rates that were not subject to a derivative instrument which fixed the interest rate. Brazil holds $1 billion of our floating rate non-recourse exposure as we have no ability to fix local debt interest rates efficiently.

In addition to utilizing non-recourse debt at a subsidiary level when available, the Parent Company provides a portion, or in certain instances all, of the remaining long-term financing or credit required to fund development, construction or acquisition of a particular project. These investments have generally taken the form of equity investments or intercompany loans, which are subordinated to the project's non-recourse loans. We generally obtain the funds for these investments from our cash flows from operations, proceeds from the sales of assets and/or the proceeds from our issuances of debt, common stock and other securities. Similarly, in certain of our businesses, the Parent Company may provide financial guarantees or other credit support 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. At December 31, 2017, 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 $842 million in aggregate (excluding those collateralized by letters of credit and other obligations discussed below).

As a result of the Parent Company's below investment grade rating, 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. At December 31, 2017, we had $36 million in letters of credit outstanding, provided under our senior secured credit facility, $52 million in letters of credit outstanding, provided under our unsecured senior credit facility. These letters of credit operate to guarantee performance relating to certain project development activities and business operations. During the year ended December 31, 2017, the Company paid letter of credit fees ranging from 0.25% to 2.25% per annum on the outstanding amounts.

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, 2017, the Company had approximately $194 million of accounts receivable classified as *Noncurrent assets—other* primarily related to certain of its generation businesses in Argentina. The noncurrent receivables mostly consist of accounts receivable in Argentina that, pursuant to amended agreements or government resolutions, have collection periods that extend beyond December 31, 2018, or one year from the latest balance sheet date. The majority of Argentinian receivables have been converted into long-term financing for the construction of power plants. See Note 6—*Financing Receivables* included in Item 8.—*Financial Statements and Supplementary Data* and Item 1.—*Business—Regulatory Matters—Argentina* of this Form 10-K for further information.

Consolidated Cash Flows

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

	December 31,			$ Change	
Cash flows provided by (used in):	**2017**	**2016**	**2015**	**2017 vs. 2016**	**2016 vs. 2015**
Operating activities	$ 2,489	$ 2,884	$ 2,134	$ (395)	$ 750
Investing activities	(2,749)	(2,108)	(2,366)	(641)	258
Financing activities	43	(747)	28	790	(775)

Operating Activities

The following table summarizes the key components of our consolidated operating cash flows (in millions):

	December 31,			$ Change	
	2017	**2016**	**2015**	**2017 vs. 2016**	**2016 vs. 2015**
Net income (loss)	$ (777)	$ (777)	$ 762	$ —	$ (1,539)
Depreciation and amortization	1,169	1,176	1,144	(7)	32
Impairment expenses	537	1,098	602	(561)	496
Loss on the extinguishment of debt	68	20	186	48	(166)
Deferred income taxes	672	(793)	(50)	1,465	(743)
Net loss from disposal and impairments of discontinued businesses	611	1,383	—	(772)	1,383
Other adjustments to net income	275	225	(73)	50	298
Non-cash adjustments to net income (loss)	3,332	3,109	1,809	223	1,300
Net income, adjusted for non-cash items	$ 2,555	$ 2,332	$ 2,571	$ 223	$ (239)
Net change in operating assets and liabilities [(1)]	(66)	552	(437)	(618)	989
Net cash provided by operating activities [(2)]	$ 2,489	$ 2,884	$ 2,134	$ (395)	$ 750

(1) Refer to the table below for explanations of the variance in operating assets and liabilities.
(2) Amounts included in the table above include the results of discontinued operations, where applicable.

Fiscal Year 2017 versus 2016

Net change in operating assets and liabilities decreased by $618 million for the year ended December 31, 2017 compared to the year ended December 31, 2016, which was primarily driven by (in millions):

Increases in:	
Accounts receivable, primarily at Maritza and Eletropaulo	$ (414)
Prepaid expenses and other current assets, primarily short-term regulatory assets at Eletropaulo and Sul	(763)
Accounts payable and other current liabilities, primarily at Eletropaulo, Tietê, Gener and Maritza, partially offset by Corporate	783
Income taxes payable, net, and other taxes payable, primarily at Gener, Tietê and Eletropaulo	252
Decreases in:	
Other liabilities, primarily due to higher deferrals into regulatory liabilities related to energy costs in 2016 compared to 2017 at Eletropaulo	(362)
Other	(114)
Total decrease in cash from changes in operating assets and liabilities	$ (618)

Fiscal Year 2016 versus 2015

Net change in operating assets and liabilities increased by $989 million for the year ended December 31, 2016 compared to the year ended December 31, 2015, which was primarily driven by (in millions):

Decreases in:	
Other assets, primarily long-term regulatory assets at Eletropaulo and service concession assets at Vietnam	$ 1,054
Accounts receivable, primarily at Maritza and Eletropaulo	615
Prepaid expenses and other current assets, primarily regulatory assets at Eletropaulo and Sul	215
Accounts payable and other current liabilities, primarily at Eletropaulo and Sul	(651)
Income taxes payable, net and other taxes payable, primarily at Tietê, Chivor and Gener	(252)
Increases in:	
Other	8
Total increase in cash from changes in operating assets and liabilities	$ 989

Investing Activities

Fiscal Year 2017 versus 2016

Net cash used in investing activities increased $641 million for the year ended December 31, 2017 compared to December 31, 2016, which was primarily driven by (in millions):

Increases in:	
Acquisitions of businesses, net of cash acquired, and equity method investees (related to the acquisitions of sPower and Alto Sertão II in 2017, partially offset by the lower acquisition of Distributed Energy projects in 2016)	$ (570)
Contributions to equity investments at OPGC and sPower	(83)
Restricted cash, debt service and other assets	(74)
Decreases in:	
Proceeds from the sale of business, net of cash sold, related to the sale of Sul in 2016, partially offset by the sale of Zimmer and Miami Fort	(523)
Short-term investments	477
Capital expenditures [(1)]	168
Other investing activities	(36)
Total increase in net cash used in investing activities	$ (641)

(1) Refer to the tables below for a breakout of capital expenditure by type and by primary business driver.

The following table summarizes the Company's capital expenditures for growth investments, maintenance and environmental reported in investing cash activities for the periods indicated (in millions):

	December 31, 2017	December 31, 2016	$ Change 2017 vs. 2016
Growth Investments	$ (1,549)	$ (1,510)	$ (39)
Maintenance	(552)	(617)	65
Environmental [(1)]	(76)	(218)	142
Total capital expenditures	$ (2,177)	$ (2,345)	$ 168

(1) Includes both recoverable and non-recoverable environmental capital expenditures. See SBU Performance Analysis for more information.

Cash used for capital expenditures decreased by $168 million for the year ended December 31, 2017 compared to December 31, 2016, which was primarily driven by (in millions):

Decreases in:	
Growth expenditures at the Andes SBU, primarily due to the completion of the Cochrane project and slower than anticipated productivity by construction contractors at Alto Maipo	$ 114
Growth expenditure at the Eurasia SBU, primarily due to timing of payments resulting in more financed capex	73
Maintenance and environmental expenditures at the US SBU, primarily due to lower spending at IPALCO on the NPDES and MATS compliance and Harding Street refueling projects, decreased spending on CCR compliance and also, decreased spending at DPL on Stuart and Killen facilities due to planned plant closures	180
Increases in:	
Growth expenditures at the US SBU, primarily due to increased spending at Southland re-powering and various Distributed Energy projects, offset by lower spending related to Eagle Valley at IPALCO	(233)
Other capital expenditures	34
Total decrease in net cash used for capital expenditures	$ 168

Fiscal Year 2016 versus 2015

Net cash used in investing activities decreased $258 million for the year ended December 31, 2016 compared to December 31, 2015, which was primarily driven by (in millions):

Increases in:	
Capital expenditures [(1)]	$ (37)
Acquisitions, net of cash acquired (primarily Distributed Energy)	(38)
Proceeds from the sales of businesses, net of cash sold (primarily related to sales of DPLER and Sul)	493
Net purchases of short-term investments	(297)
Decreases in:	
Restricted cash, debt service and other assets	98
Other investing activities	39
Total decrease in net cash used in investing activities	$ 258

(1) Refer to the tables below for a breakout of capital expenditures by type and by primary business driver.

The following table summarizes the Company's capital expenditures for growth investments, maintenance and environmental for the periods indicated (in millions):

	December 31, 2016	December 31, 2015	$ Change 2016 vs. 2015
Growth Investments	$ (1,510)	$ (1,401)	$ (109)
Maintenance	(617)	(606)	(11)
Environmental [1]	(218)	(301)	83
Total capital expenditures	$ (2,345)	$ (2,308)	$ (37)

[1] Includes both recoverable and non-recoverable environmental capital expenditures.

Cash used for capital expenditures increased by $37 million for the year ended December 31, 2016 compared to December 31, 2015, which was primarily driven by (in millions):

Increases in:	
Growth expenditures at the Eurasia SBU for the construction of the Masinloc expansion and retrofit related costs to the existing plant to increasing capacity	$ (124)
Growth expenditures at the MCAC SBU for the construction of Colon and Los Mina	(266)
Decreases In:	
Growth expenditures at the Andes SBU, primarily due to lower spending at Cochrane and the Andes Solar plant; partially offset by higher investments in Alto Maipo	280
Growth expenditures at the US SBU, primarily due to lower spending related to Eagle Valley and Transmission & Distribution projects at IPALCO	20
Maintenance and environmental expenditures at the US SBU, primarily due to lower spending related to MATS compliance and the conversion of Harding Street Stations 5, 6 and 7 to natural gas upon being placed into service in late 2015 and early 2016; partially offset by higher spending on CCR compliance	63
Other capital expenditures	(10)
Total increase in net cash used for capital expenditures	$ (37)

Financing Activities

Net cash used in financing activities decreased $790 million for the year ended December 31, 2017 compared to December 31, 2016, which was primarily driven by (in millions):

Decreases in:	
Proceeds from the sale of redeemable stock of subsidiaries at IPALCO	$ (134)
Contributions from noncontrolling interests and redeemable security holders at MCAC and US SBUs	(117)
Repayment of non-recourse debt, primarily at the Brazil, US, Eurasia and MCAC SBUs [1]	550
Increases in:	
Borrowings under the revolving credit facilities, primarily at the Parent Company and net decrease in repayments at the US SBU	382
Proceeds from sale of noncontrolling interests primarily related to the sell down of Dominican Republic business in 2017	94
Other financing activities	15
Total decrease in net cash used in financing activities	$ 790

[1] See Note 10—*Debt* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for more information regarding significant recourse debt transactions.

Net cash provided by financing activities increased $775 million for the year ended December 31, 2016 compared to the year ended December 31, 2015, which was primarily driven by (in millions):

Increases in:	
Distributions to noncontrolling interests, primarily at the Brazil SBU	$ (150)
Contributions from noncontrolling interests, primarily at the MCAC SBU	64
Decreases in:	
Net issuance of non-recourse debt, primarily at the Andes and Brazil SBUs	(624)
Proceeds from the sale of redeemable stock of subsidiaries at IPALCO	(327)
Proceeds from sales to noncontrolling interests, net of transaction costs	(154)
Purchases of treasury stock by the Parent Company	403
Net repayments of recourse debt at the Parent Company [1]	32
Other financing activities	(19)
Total increase in net cash provided by financing activities	$ (775)

[1] See Note 10—*Debt* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for more information regarding significant recourse debt transactions.

Parent Company Liquidity

The following discussion of Parent Company Liquidity 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 as a measure of liquidity. *Cash and cash equivalents* is disclosed on the Consolidated Statements of Cash Flows. 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 credit facility, and proceeds from asset sales. Cash requirements at the Parent Company level are primarily to fund interest; principal repayments of debt; construction commitments; other equity commitments; common stock repurchases; 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 plus available borrowings under existing credit facility. 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 U.S. GAAP financial measure, *Cash and cash equivalents*, at December 31, 2017 and 2016 as follows:

Parent Company Liquidity (in millions)	**2017**	**2016**
Consolidated cash and cash equivalents	$ 949	$ 1,244
Less: Cash and cash equivalents at subsidiaries	938	1,144
Parent and qualified holding companies' cash and cash equivalents	11	100
Commitments under Parent Company credit facilities	1,100	800
Less: Letters of credit under the credit facilities	(35)	(6)
Less: Borrowings under the credit facilities	(207)	—
Borrowings available under Parent Company credit facilities	858	794
Total Parent Company Liquidity	$ 869	$ 894

The Parent Company paid dividends of $0.48 per share to its common stockholders during the year ended December 31, 2017. While we intend to continue payment of dividends and believe we will have sufficient liquidity to do so, we can provide no assurance that we will continue to pay dividends, or if continued, the amount of such dividends.

Recourse Debt

Our total recourse debt was $4.6 billion and $4.7 billion at December 31, 2017 and 2016, respectively. See Note 10—*Debt* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional detail.

While 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 (see *Key Trends and Uncertainties—Macroeconomic and Political*), 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. See Item 1A.—*Risk Factors—The AES Corporation is a holding company and its ability to make payments on its outstanding indebtedness, including its public debt securities, is dependent upon the receipt of funds from its subsidiaries by way of dividends, fees, interest, loans or otherwise,* of this Form 10-K.

Various debt instruments at the Parent Company level, including our senior secured credit facility, 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, 2017, 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 senior secured credit facility and outstanding debt securities at the Parent Company include events of default for certain bankruptcy related events involving material subsidiaries. In addition, our revolving credit agreement at the Parent Company includes events of default related to payment defaults and accelerations of outstanding debt of material subsidiaries.

Some of our subsidiaries are currently in default with respect to all or a portion of their outstanding indebtedness. The total non-recourse debt classified as current in the accompanying Consolidated Balance Sheets amounts to $2.2 billion. The portion of current debt related to such defaults was $1 billion at December 31, 2017, all of which was non-recourse debt related to three subsidiaries — Alto Maipo, AES Puerto Rico, and AES Ilumina. See Note 10—*Debt* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional detail.

None of the subsidiaries that are currently in default are subsidiaries that met the applicable definition of materiality under AES' corporate debt agreements as of December 31, 2017 in order for such defaults to trigger an event of default or permit acceleration under AES' 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 upon an acceleration 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 Company's senior secured revolving credit facility 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, 2017, none of the defaults listed above individually or in the aggregate results in or is at risk of triggering a cross-default under the recourse debt of the Company.

Contractual Obligations and Parent Company Contingent Contractual Obligations

A summary of our contractual obligations, commitments and other liabilities as of December 31, 2017 is presented below and excludes any businesses classified as discontinued operations or held-for-sale (in millions):

Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**	**Other**	**Footnote Reference[(4)]**
Debt Obligations [(1)]	$ 20,404	$ 2,250	$ 2,431	$ 5,003	$ 10,720	$ —	10
Interest Payments on Long-Term Debt [(2)]	9,103	1,172	2,166	1,719	4,046	—	n/a
Capital Lease Obligations	18	2	2	2	12	—	11
Operating Lease Obligations	935	58	116	117	644	—	11
Electricity Obligations	4,501	581	948	907	2,065	—	11
Fuel Obligations	5,859	1,759	1,642	992	1,466	—	11
Other Purchase Obligations	4,984	1,488	1,401	781	1,314	—	11
Other Long-Term Liabilities Reflected on AES' Consolidated Balance Sheet under GAAP [(3)]	701	—	284	118	277	22	n/a
Total	$ 46,505	$ 7,310	$ 8,990	$ 9,639	$ 20,544	$ 22	

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

(2) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 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, 2017.

(3) These amounts do not include current liabilities on the Consolidated Balance Sheet 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 9—*Regulatory Assets and Liabilities*), (2) contingencies (See Note 12—*Contingencies*), (3) pension and other postretirement employee benefit liabilities (see Note 13—*Benefit Plans*), (4) derivatives and incentive compensation (See Note 5—*Derivative Instruments and Hedging Activities*) or (5) any taxes (See Note 20—*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 of this Form 10-K for additional information on the items excluded.

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

The following table presents our Parent Company's contingent contractual obligations as of December 31, 2017:

Contingent contractual obligations	Amount (in millions)	Number of Agreements	Maximum Exposure Range for Each Agreement (in millions)
Guarantees and commitments	$ 815	21	$1 — 272
Letters of credit under the unsecured credit facility	52	4	$2 — 26
Asset sale related indemnities [1]	27	1	27
Letters of credit under the senior secured credit facility	36	21	<$1 — 13
Total	$ 930	47	

(1) Excludes 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.

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. In addition, we have an asset sale program through which we may have customary indemnity obligations under certain assets sale agreements. While we do not expect that we will be required to fund any material amounts under these contingent contractual obligations beyond 2017, 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 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. As an example, new tax laws were enacted in December 2017 in the U.S. which decreased the statutory income tax rate from 35% to 21%, required a one-time transition tax, and introduced numerous other changes. As further outlined in *Key Trends and Uncertainties*, the Company anticipates that the new GILTI provisions of U.S. tax reform could materially impact the effective tax rate in future periods.

Accordingly, in 2017 our net U.S. deferred tax liabilities were remeasured to the new rates. The potential future impacts of the changes in tax law may be material to continuing operations. See Note 20—*Income Taxes* to the Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information.

The Company's provision for income taxes could be adversely impacted by changes to the U.S. taxation of earnings of our foreign subsidiaries. In accordance with SAB 118, the Company has made reasonable estimates of the impacts of U.S. tax reform on its 2017 financial results, subject to potential adjustments as we complete our analysis. Our expected effective tax rate could increase by amounts that may be material to the Company.

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.

Sales of Noncontrolling Interests — The accounting for a sale of noncontrolling interest under the accounting standards depends on whether the sale is considered to be a sale of in-substance real estate, where the gain (loss) on sale would be recognized in earnings rather than within stockholders' equity. If management's estimation process determines that there is no significant value beyond the in-substance real estate, the gain (loss) on the sale of the noncontrolling interest is recognized in earnings. However, if it is determined that significant value likely exists beyond the in-substance real estate, the gain (loss) on the sale of the noncontrolling interest would be recognized within stockholders' equity.

In-substance real estate is composed of land plus improvements and integral equipment. The determination of whether property, plant and equipment is integral equipment is based on the significance of the costs to remove the equipment from its existing location (including the cost of repairing damage resulting from the removal), combined with the decrease in the fair value of the equipment as a result of those removal activities. When the combined total of removal costs and the decrease in fair value of the equipment exceeds 10% of the fair value of the equipment, the equipment is considered integral equipment. The accounting standards specifically identify power plants as an example of in-substance real estate. Where the consolidated entity in which noncontrolling interests have been sold contains in-substance real estate, management estimates the extent to which the total fair value of the assets of the entity is represented by the in-substance real estate and whether significant value exists beyond the in-substance real estate. This estimation considers all qualitative and quantitative factors relevant for each sale and, where appropriate, includes making quantitative estimates about the fair value of the entity and its identifiable assets and liabilities (including any favorable or unfavorable contracts) by analogy to the accounting standards on business combinations. As such, these estimates may require significant judgment and assumptions, similar to the critical accounting estimates discussed below for impairments and fair value.

Impairments — Our accounting policies on goodwill and long-lived assets are described in detail in Note 1—*General and Summary of Significant Accounting Policies*, included in Item 8 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. Events that may result in an impairment analysis being performed 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. The Company exercises judgment in determining if these 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 gap between fair value and carrying amount decreases. 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 8—*Goodwill and Other Intangible Assets and* Note 19—*Asset Impairment Expense* to the Consolidated Financial

Statements included in Item 8 of this Form 10-K.

Fair Value

Fair Value — For information regarding the fair value hierarchy, see Note 1—*General and Summary of Significant Accounting Policies* included in Item 8 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, government debt securities and money market 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 4—*Fair Value* included in Item 8 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 majority of assets acquired and liabilities assumed in a business combination are required to be recognized at fair value under the relevant accounting guidance.

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 our internal budgets and 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 internal budgets and cash flow forecasts. Examples of the input assumptions that our budgets and forecasts are sensitive to include macroeconomic factors such as growth rates, industry demand, inflation, exchange rates, power prices 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 5—*Derivative Instruments and Hedging Activities* included in Item 8 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). Due to the nature of the Company's interest rate swaps, which are typically associated with non-recourse debt, credit risk for AES is evaluated at the subsidiary level rather than at the Parent Company level. Nonperformance risk on the Company's derivative instruments is an adjustment to the initial asset/liability fair value position that is derived from internally developed valuation models that utilize observable market inputs.

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 (both ours and our counterparty's), and future exchange rates. Refer to Note 4—*Fair Value* included in Item 8 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, the published curve 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. Additionally, in the absence of quoted prices, we may rely on "indicative pricing" quotes from financial institutions to input into our valuation model for certain of our foreign currency swaps. These indicative pricing quotes do not constitute either a bid or ask price and therefore are not considered observable market data. 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 the 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, establishing operating and capital decisions of the entity, including budgets, in the ordinary course of business. On the other hand, if shareholder rights are only protective in nature (referred to as protective rights) then such rights would not overcome the presumption that the owner of a majority voting interest shall consolidate its investee. Significant judgment is required to determine whether minority rights represent substantive participating rights or protective rights that do not affect the evaluation of control. While both represent an approval or veto right, a distinguishing factor is the underlying activity or action to which the right relates.

Pension and Other Postretirement Plans — The Company recognizes a net asset or liability reflecting the funded status of pension and other postretirement plans with current-year changes in actuarial gains or losses recognized in AOCL, except for those plans at certain of the Company's regulated utilities that can recover portions of their pension and postretirement obligations through future rates. The valuation of the Company's benefit obligation, fair value of plan assets, and net periodic benefit costs requires various estimates and assumptions, the most significant of which include the discount rate and expected return on plan assets. These assumptions are reviewed by the Company on an annual basis. Refer to Note 1—*General and Summary of Significant Accounting Policies* included in Item 8 of this Form 10-K for further information.

New Accounting Pronouncements — See Note 1—*General and Summary of Significant Accounting Policies* included in Item 8 of this Form 10-K for further information about new accounting pronouncements adopted during 2017 and accounting pronouncements issued but not yet effective.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Overview Regarding Market Risks — Our businesses are exposed to and proactively manage market risk. Our primary market risk exposure is to the price of commodities, particularly electricity, oil, natural gas, coal and environmental credits. In addition, our businesses are also exposed to lower electricity prices due to increased competition, including from renewable sources such as wind and solar, as a result of lower costs of entry and lower variable costs. 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 U.S. dollar, and currencies of the countries in which we operate. We are also exposed to interest rate fluctuations due to our issuance of debt and related financial instruments.

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 Securities Exchange Act of 1934 shall apply to the disclosures contained in this Item 7A. For further information regarding market risk, see Item 1A.—*Risk Factors*, *Our financial position and results of operations may fluctuate significantly due to fluctuations in currency exchange rates experienced at our foreign operations*, *Our businesses may incur substantial costs and liabilities and be exposed to price volatility as a result of risks associated with the electricity markets, which could have a material adverse effect on our financial performance,* and *We may not be adequately hedged against our exposure to changes in commodity prices or interest rates* of this 2017 Form 10-K.

Commodity Price Risk — Although we prefer to hedge our exposure to the impact of market fluctuations in the price of electricity, fuels and environmental credits, some of our generation businesses operate under short-term sales or under contract sales that leave an unhedged exposure on some of our capacity or through imperfect fuel pass-throughs. In our utility businesses, we may be exposed to commodity price movements depending on our excess or shortfall of generation relative to load obligations and sharing or pass-through mechanisms. These businesses subject our operational results to the volatility of prices for electricity, fuels and environmental credits in competitive markets. We employ risk management strategies to hedge our financial performance against the effects of fluctuations in energy commodity prices. The implementation of these strategies can involve the use of physical and financial commodity contracts, futures, swaps and options.

The portion of our sales and purchases that are not subject to such agreements or contracted businesses where indexation is not perfectly matched to business drivers will be exposed to commodity price risk. When hedging the output of our generation assets, we utilize contract sales that lock in the spread per MWh between variable costs and the price at which the electricity can be sold.

AES businesses will see changes in variable margin performance as global commodity prices shift. For 2018, we project pre-tax earnings exposure on a 10% move in commodity prices would be approximately $10 million for U.S. power (DPL), less than $5 million for natural gas, $5 million for oil and $5 million for coal. Our estimates exclude correlation of oil with coal or natural gas. For example, a decline in oil or natural gas prices can be accompanied by a decline in coal price if commodity prices are correlated. In aggregate, the Company's downside exposure occurs with lower oil, lower natural gas, and higher coal prices. Exposures at individual businesses will change as new contracts or financial hedges are executed, and our sensitivity to changes in commodity prices generally increases in later years with reduced hedge levels at some of our businesses.

Commodity prices affect our businesses differently depending on the local market characteristics and risk management strategies. Spot power prices, contract indexation provisions and generation costs can be directly or indirectly affected by movements in the price of natural gas, oil and coal. We have some natural offsets across our businesses such that low commodity prices may benefit certain businesses and be a cost to others. Exposures are not perfectly linear or symmetric. The sensitivities are affected by a number of local or indirect market factors. Examples of these factors include hydrology, local energy market supply/demand balances, regional fuel supply issues, regional competition, bidding strategies and regulatory interventions such as price caps. Operational flexibility changes the shape of our sensitivities. For instance, certain power plants may limit downside exposure by reducing dispatch in low market environments. 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.

In the US SBU, the generation businesses are largely contracted but may have residual risk to the extent contracts are not perfectly indexed to the business drivers. IPL primarily generates energy to meet its retail customer demand; however, it opportunistically sells surplus economic energy into wholesale markets at market prices. Additionally, at DPL, competitive retail markets permit our customers to select alternative energy suppliers or elect to remain in aggregated customer pools for which energy is supplied by third party suppliers through a competitive auction process. DPL participates in these auctions held by other utilities and sells the remainder of its economic energy into the wholesale market. Given that natural gas-fired generators generally get energy prices for many markets, higher natural gas prices tend to expand our coal fixed margins. Our non-contracted generation margins are impacted by many factors, including the growth in natural gas-fired generation plants, new energy supply from renewable sources, and increasing energy efficiency.

In the Andes SBU, our business in Chile owns assets in the central and northern regions of the country and has a portfolio of contract sales in both. In the central region, the contract sales generally cover the efficient generation from our coal-fired and hydroelectric assets. Any residual spot price risk will primarily be driven by the amount of hydrological inflows. In the case of low hydroelectric generation, spot price exposure is capped by the ability to dispatch our natural gas/diesel assets, the price of which depends on fuel pricing at the time required. There is a small amount of coal generation in the northern region that is not covered by the portfolio of contract sales and therefore subject to spot price risk. In both regions, generators with oil or oil-linked fuel generally set power prices. In Colombia, we operate under a short-term sales strategy and have commodity exposure to unhedged volumes. Because we own hydroelectric assets there, contracts are not indexed to fuel.

In the Brazil SBU, the hydroelectric generating facility is covered by contract sales. Under normal hydrological volatility, spot price risk is mitigated through a regulated sharing mechanism across all hydroelectric generators in the country. Under drier conditions, the sharing mechanism may not be sufficient to cover the business' contract position, and therefore it may have to purchase power at spot prices driven by the cost of thermal generation.

In the MCAC SBU, our businesses have commodity exposure on unhedged volumes. Panama is highly contracted under a portfolio of fixed volume contract sales. To the extent hydrological inflows are greater than or less than the contract sales volume, the business will be sensitive to changes in spot power prices which may be driven by oil prices in some time periods. In the Dominican Republic, we own natural gas-fired assets contracted under a portfolio of contract sales and a coal-fired asset contracted with a single contract, and both contract and spot prices may move with commodity prices. Additionally, the contract levels do not always match our generation availability 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.

In the Eurasia SBU, our Kilroot facility operates on a short-term sales strategy. To the extent that sales are unhedged, the commodity risk at our Kilroot business is to the clean dark spread, which is the difference between electricity price and our coal-based variable dispatch cost, including emissions. Natural gas-fired generators set power prices for many periods, so higher natural gas prices generally expand margins and higher coal or emissions prices reduce them. Similarly, increased wind generators displace higher cost generation, reducing Kilroot's margins, and vice versa. Two coal-fired generating units at Kilroot and one steam gas generating unit at Ballylumford are expected to close by the end of May 2018 as a result of unfavorable capacity market conditions in Northern Ireland. The remaining steam gas generating unit at Ballylumford and the OCGTs at both Ballylumford and Kilroot will continue to operate as peaking units at times of high demand. Our Masinloc business is a coal-fired generation facility which hedges its output under a portfolio of contract sales that are indexed to fuel prices, with generation in excess of contract volume or shortfalls of generation relative to contract volumes settled in the spot market. Low oil prices may be a driver of margin compression since oil affects spot power sale prices sold in the spot market. Our Mong Duong business has minimal exposure to commodity price risk as it has no merchant exposure and fuel is subject to a pass-through mechanism.

Foreign Exchange Rate Risk — In the normal course of business, we are exposed to foreign currency risk and other foreign operations risks that arise from investments in foreign subsidiaries and affiliates. A key component of these risks stems from the fact that some of our foreign subsidiaries and affiliates utilize currencies other than our consolidated reporting currency, the U.S. dollar ("USD"). Additionally, certain of our foreign subsidiaries and affiliates have entered into monetary obligations in USD or currencies other than their own functional currencies. We have varying degrees of exposure to changes in the exchange rate between the USD and the following currencies: Argentine peso, British pound, Brazilian real, Chilean peso, Colombian peso, Dominican peso, Euro, Indian rupee, and Mexican peso. These subsidiaries and affiliates have attempted 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 cash flow hedges to protect economic value of the business and minimize impact of foreign exchange rate fluctuations to AES' portfolio. While protecting cash flows, the hedging strategy is also designed to reduce forward-looking earnings foreign exchange volatility. Due to variation of timing and amount between cash distribution 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. The largest foreign exchange risks over a 12-month forward-looking period stem from the following currencies: Brazilian real, Euro, and British pound. As of December 31, 2017, assuming a 10% USD appreciation, cash distributions attributable to foreign subsidiaries exposed to movement in the exchange rate of the Brazilian real, Euro, and British pound each is projected to be reduced by less than $5 million. These numbers have been produced by applying a one-time 10% USD appreciation to forecasted exposed cash distributions for 2018 coming from the respective subsidiaries exposed to the currencies listed above, net of the impact of outstanding hedges and holding all other variables constant. The numbers presented above are net of any transactional gains/losses. These sensitivities may change in the future as new hedges are executed or existing hedges are unwound. Additionally, updates to the forecasted cash distributions exposed to foreign exchange risk may result in further modification. The sensitivities presented do not capture the impacts of any administrative market restrictions or currency inconvertibility.

Interest Rate Risks — We are exposed to risk resulting from changes in interest rates as a result of our issuance of variable and fixed-rate debt, as well as interest rate swap, cap, floor and option agreements.

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, 2017, the portfolio's pre-tax earnings exposure for 2018 to a one-time 100-basis-point increase in interest rates for our Argentine peso, Brazilian real, Chilean peso, Colombian peso, Euro and USD denominated debt would be approximately $25 million on interest expense for the debt denominated in these currencies. These amounts do not take into account the historical correlation between these interest rates.

ITEM 8. 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, 2017 and 2016, and the related consolidated statements of operations, comprehensive loss, changes in equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and the financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "financial statements"). In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2017 and 2016, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, 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, 2017, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 26, 2018, 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 include 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.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2008.

Tysons, Virginia
February 26, 2018

THE AES CORPORATION

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 2017 AND 2016

	2017	2016
	(in millions, except share and per share data)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 949	$ 1,244
Restricted cash	274	277
Short-term investments	424	530
Accounts receivable, net of allowance for doubtful accounts of $10 and $17, respectively	1,463	1,421
Inventory	562	622
Prepaid expenses	62	72
Other current assets	630	657
Current assets of discontinued operations and held-for-sale businesses	2,034	1,593
Total current assets	6,398	6,416
NONCURRENT ASSETS		
Property, Plant and Equipment:		
Land	502	518
Electric generation, distribution assets and other	24,119	24,911
Accumulated depreciation	(7,942)	(7,919)
Construction in progress	3,617	2,905
Property, plant and equipment, net	20,296	20,415
Other Assets:		
Investments in and advances to affiliates	1,197	621
Debt service reserves and other deposits	565	438
Goodwill	1,059	1,157
Other intangible assets, net of accumulated amortization of $441 and $399, respectively	366	287
Deferred income taxes	130	227
Service concession assets, net of accumulated amortization of $206 and $114, respectively	1,360	1,445
Other noncurrent assets	1,741	1,775
Noncurrent assets of discontinued operations and held-for-sale businesses	—	3,343
Total other assets	6,418	9,293
TOTAL ASSETS	$ 33,112	$ 36,124
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 1,371	$ 1,238
Accrued interest	228	216
Accrued and other liabilities	1,232	1,117
Non-recourse debt, including $1,012 and $273, respectively, related to variable interest entities	2,164	1,052
Current liabilities of discontinued operations and held-for-sale businesses	1,033	1,654
Total current liabilities	6,028	5,277
NONCURRENT LIABILITIES		
Recourse debt	4,625	4,671
Non-recourse debt, including $1,358 and $1,502 respectively, related to variable interest entities	13,176	13,731
Deferred income taxes	1,006	804
Pension and other postretirement liabilities	230	237
Other noncurrent liabilities	2,365	2,327
Noncurrent liabilities of discontinued operations and held-for-sale businesses	—	2,595
Total noncurrent liabilities	21,402	24,365
Commitments and Contingencies (see Notes 11 and 12)		
Redeemable stock of subsidiaries	837	782
EQUITY		
THE AES CORPORATION STOCKHOLDERS' EQUITY		
Common stock ($0.01 par value, 1,200,000,000 shares authorized; 816,312,913 issued and 660,388,128 outstanding at December 31, 2017 and 816,061,123 issued and 659,182,232 outstanding at December 31, 2016)	8	8
Additional paid-in capital	8,501	8,592
Accumulated deficit	(2,276)	(1,146)
Accumulated other comprehensive loss	(1,876)	(2,756)
Treasury stock, at cost (155,924,785 and 156,878,891 shares at December 31, 2017 and 2016, respectively)	(1,892)	(1,904)
Total AES Corporation stockholders' equity	2,465	2,794
NONCONTROLLING INTERESTS	2,380	2,906
Total equity	4,845	5,700
TOTAL LIABILITIES AND EQUITY	$ 33,112	$ 36,124

See Accompanying Notes to Consolidated Financial Statements.

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015

	2017	2016	2015
	(in millions, except per share amounts)		
Revenue:			
Regulated	$ 3,109	$ 3,310	$ 3,240
Non-Regulated	7,421	6,971	8,020
Total revenue	10,530	10,281	11,260
Cost of Sales:			
Regulated	(2,656)	(2,844)	(3,074)
Non-Regulated	(5,410)	(5,057)	(5,523)
Total cost of sales	(8,066)	(7,901)	(8,597)
Operating margin	2,464	2,380	2,663
General and administrative expenses	(215)	(194)	(196)
Interest expense	(1,170)	(1,134)	(1,145)
Interest income	244	245	256
Loss on extinguishment of debt	(68)	(13)	(182)
Other expense	(57)	(79)	(24)
Other income	120	64	84
Gain (loss) on disposal and sale of businesses	(52)	29	29
Goodwill impairment expense	—	—	(317)
Asset impairment expense	(537)	(1,096)	(285)
Foreign currency transaction gains (losses)	42	(15)	106
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES AND EQUITY IN EARNINGS OF AFFILIATES	771	187	989
Income tax expense	(990)	(32)	(412)
Net equity in earnings of affiliates	71	36	105
INCOME (LOSS) FROM CONTINUING OPERATIONS	(148)	191	682
Income (loss) from operations of discontinued businesses, net of income tax benefit (expense) of $(21), $229, and $(53), respectively	(18)	151	80
Net loss from disposal and impairments of discontinued businesses, net of income tax benefit of $0, $266, and $0, respectively	(611)	(1,119)	—
NET INCOME (LOSS)	(777)	(777)	762
Noncontrolling interests:			
Less: Income from continuing operations attributable to noncontrolling interests and redeemable stock of subsidiaries	(359)	(211)	(364)
Less: Income from discontinued operations attributable to noncontrolling interests	(25)	(142)	(92)
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ (1,161)	$ (1,130)	$ 306
AMOUNTS ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:			
Income (loss) from continuing operations, net of tax	$ (507)	$ (20)	$ 318
Loss from discontinued operations, net of tax	(654)	(1,110)	(12)
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ (1,161)	$ (1,130)	$ 306
BASIC EARNINGS PER SHARE:			
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ (0.77)	$ (0.04)	$ 0.46
Loss from discontinued operations attributable to The AES Corporation common stockholders, net of tax	(0.99)	(1.68)	(0.01)
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ (1.76)	$ (1.72)	$ 0.45
DILUTED EARNINGS PER SHARE:			
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ (0.77)	$ (0.04)	$ 0.46
Loss from discontinued operations attributable to The AES Corporation common stockholders, net of tax	(0.99)	(1.68)	(0.02)
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ (1.76)	$ (1.72)	$ 0.44
DIVIDENDS DECLARED PER COMMON SHARE	$ 0.49	$ 0.45	$ 0.41

See Accompanying Notes to Consolidated Financial Statements.

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015

	2017	2016	2015
		(in millions)	
NET INCOME (LOSS)	$ (777)	$ (777)	$ 762
Foreign currency translation activity:			
Foreign currency translation adjustments, net of income tax benefit (expense) of $17, $1, and $1, respectively	(9)	189	(1,019)
Reclassification to earnings, net of $0 income tax for all periods	643	992	—
Total foreign currency translation adjustments	634	1,181	(1,019)
Derivative activity:			
Change in derivative fair value, net of income tax benefit (expense) of $10, $(7) and $16, respectively	(12)	5	(57)
Reclassification to earnings, net of income tax expense of $1, $8 and $11, respectively	50	37	66
Total change in fair value of derivatives	38	42	9
Pension activity:			
Change in pension adjustments due to prior service cost, net of income tax expense of $1, $6, and $0 respectively	2	11	1
Change in pension adjustments due to net actuarial gain (loss) for the period, net of income tax benefit (expense) of $6, $106, and $(29), respectively	(21)	(208)	60
Reclassification to earnings, net of income tax expense of $135, $3, and $9, respectively	266	10	16
Total pension adjustments	247	(187)	77
OTHER COMPREHENSIVE INCOME (LOSS)	919	1,036	(933)
COMPREHENSIVE INCOME (LOSS)	142	259	(171)
Less: Comprehensive income attributable to noncontrolling interests	(390)	(262)	(133)
COMPREHENSIVE LOSS ATTRIBUTABLE TO THE AES CORPORATION	$ (248)	$ (3)	$ (304)

See Accompanying Notes to Consolidated Financial Statements.

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015

	THE AES CORPORATION STOCKHOLDERS							
	Common Stock		Treasury Stock					
(in millions)	Shares	Amount	Shares	Amount	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Loss	Noncontrolling Interests
Balance at December 31, 2014	814.5	$ 8	110.7	$ (1,371)	$ 8,409	$ 512	$ (3,286)	$ 3,053
Net income	—	—	—	—	—	306	—	456
Total foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	(674)	(345)
Total change in derivative fair value, net of income tax	—	—	—	—	—	—	43	(34)
Total pension adjustments, net of income tax	—	—	—	—	—	—	21	56
Total other comprehensive loss							(610)	(323)
Cumulative effect of a change in accounting principle	—	—	—	—	—	(18)	13	—
Acquisition of a business [(1)]	—	—	—	—	—	—	—	15
Disposition of businesses	—	—	—	—	—	—	—	(41)
Distributions to noncontrolling interests	—	—	—	—	(27)	—	—	(383)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	126
Dividends declared on common stock	—	—	—	—	—	(280)	—	—
Purchase of treasury stock	—	—	39.7	(482)	—	—	—	—
Issuance and exercise of stock-based compensation benefit plans, net of income tax	1.3	—	(1.4)	16	13	—	—	—
Sale of subsidiary shares to noncontrolling interests	—	—	—	—	323	(377)	—	119
Balance at December 31, 2015	815.8	$ 8	149.0	$ (1,837)	$ 8,718	$ 143	$ (3,883)	$ 3,022
Net income (loss)	—	—	—	—	—	(1,130)	—	353
Total foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	1,109	72
Total change in derivative fair value, net of income tax	—	—	—	—	—	—	30	12
Total pension adjustments, net of income tax	—	—	—	—	—	—	(12)	(175)
Total other comprehensive income (loss)							1,127	(91)
Fair value adjustment [(2)]	—	—	—	—	17	(4)	—	(17)
Disposition of businesses	—	—	—	—	—	—	—	(2)
Distributions to noncontrolling interests	—	—	—	—	(10)	—	—	(430)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	60
Dividends declared on common stock	—	—	—	—	(226)	(71)	—	—
Purchase of treasury stock	—	—	8.7	(79)	—	—	—	—
Issuance and exercise of stock-based compensation benefit plans, net of income tax	0.3	—	(0.8)	12	11	—	—	—
Sale of subsidiary shares to noncontrolling interests	—	—	—	—	84	(84)	—	17
Acquisition and reclassification of subsidiary shares from noncontrolling interests	—	—	—	—	(2)	—	—	(17)
Less: Net loss attributable to redeemable stock of subsidiaries [(3)]	—	—	—	—	—	—	—	11
Balance at December 31, 2016	816.1	$ 8	156.9	$ (1,904)	$ 8,592	$ (1,146)	$ (2,756)	$ 2,906
Net income (loss)	—	—	—	—	—	(1,161)	—	384
Total foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	661	(27)
Total change in derivative fair value, net of income tax	—	—	—	—	—	—	23	15
Total pension adjustments, net of income tax	—	—	—	—	—	—	229	18
Total other comprehensive income							913	6
Cumulative effect of a change in accounting principle	—	—	—	—	—	31	—	—
Fair value adjustment [(2)]	—	—	—	—	(25)	—	—	—
Disposition of businesses	—	—	—	—	—	—	—	(666)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(426)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	11
Dividends declared on common stock	—	—	—	—	(324)	—	—	—
Issuance and exercise of stock-based compensation benefit plans, net of income tax	0.2	—	(1.0)	12	5	—	—	—
Sale of subsidiary shares to noncontrolling interests	—	—	—	—	13	—	7	83
Acquisition of subsidiary shares from noncontrolling interests	—	—	—	—	240	—	(40)	68
Less: Net loss attributable to redeemable stock of subsidiaries [(3)]	—	—	—	—	—	—	—	14
Balance at December 31, 2017	816.3	$ 8	155.9	$ (1,892)	$ 8,501	$ (2,276)	$ (1,876)	$ 2,380

[(1)] Fair value of a tax equity partner's right to preferential returns recognized as a result of the acquisition of Solar Power PR, LLC, which was previously accounted for as an equity method investment.

[(2)] Adjustment to the carrying amount of noncontrolling interest and redeemable stock of subsidiaries to fair value.

[(3)] Net income attributable to noncontrolling interest of $398 million and net loss attributable to redeemable stock of subsidiaries of $14 million for the year ended December 31, 2017. Net income attributable to noncontrolling interest of $364 million and net loss attributable to redeemable stock of subsidiaries of $11 million for the year ended December 31, 2016.

See Accompanying Notes to Consolidated Financial Statements

THE AES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015

	2017	2016	2015
		(in millions)	
OPERATING ACTIVITIES:			
Net income (loss)	$ (777)	$ (777)	$ 762
Adjustments to net income (loss):			
Depreciation and amortization	1,169	1,176	1,144
Loss (gain) on sales and disposals of businesses	52	(29)	(29)
Impairment expenses	537	1,098	602
Deferred income taxes	672	(793)	(50)
Provisions for (reversals of) contingencies	34	48	(72)
Loss on extinguishment of debt	68	20	186
Loss on sale and disposal of assets	43	38	20
Net loss from disposal and impairments of discontinued businesses	611	1,383	—
Other	146	168	8
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(177)	237	(378)
(Increase) decrease in inventory	(28)	42	(26)
(Increase) decrease in prepaid expenses and other current assets	107	870	655
(Increase) decrease in other assets	(295)	(251)	(1,305)
Increase (decrease) in accounts payable and other current liabilities	163	(620)	31
Increase (decrease) in income tax payables, net and other tax payables	53	(199)	53
Increase (decrease) in other liabilities	111	473	533
Net cash provided by operating activities	2,489	2,884	2,134
INVESTING ACTIVITIES:			
Capital expenditures	(2,177)	(2,345)	(2,308)
Acquisitions of businesses, net of cash acquired, and equity method investments	(625)	(55)	(17)
Proceeds from the sale of businesses, net of cash sold, and equity method investments	108	631	138
Sale of short-term investments	3,540	4,904	4,851
Purchase of short-term investments	(3,310)	(5,151)	(4,801)
Increase in restricted cash, debt service reserves, and other assets	(135)	(61)	(159)
Contributions to equity investments	(89)	(6)	(3)
Other investing	(61)	(25)	(67)
Net cash used in investing activities	(2,749)	(2,108)	(2,366)
FINANCING ACTIVITIES:			
Borrowings under the revolving credit facilities	2,156	1,465	959
Repayments under the revolving credit facilities	(1,742)	(1,433)	(937)
Issuance of recourse debt	1,025	500	575
Repayments of recourse debt	(1,353)	(808)	(915)
Issuance of non-recourse debt	3,222	2,978	4,248
Repayments of non-recourse debt	(2,360)	(2,666)	(3,312)
Payments for financing fees	(100)	(105)	(90)
Distributions to noncontrolling interests	(424)	(476)	(326)
Contributions from noncontrolling interests and redeemable security holders	73	190	126
Proceeds from the sale of redeemable stock of subsidiaries	—	134	461
Dividends paid on AES common stock	(317)	(290)	(276)
Payments for financed capital expenditures	(179)	(113)	(150)
Purchase of treasury stock	—	(79)	(482)
Proceeds from sales to noncontrolling interests, net of transaction costs	94	—	154
Other financing	(52)	(44)	(7)
Net cash provided by (used in) financing activities	43	(747)	28
Effect of exchange rate changes on cash	3	9	(52)
Decrease (increase) in cash of discontinued operations and held-for-sale businesses	(81)	(12)	25
Total increase (decrease) in cash and cash equivalents	(295)	26	(231)
Cash and cash equivalents, beginning	1,244	1,218	1,449
Cash and cash equivalents, ending	$ 949	$ 1,244	$ 1,218
SUPPLEMENTAL DISCLOSURES:			
Cash payments for interest, net of amounts capitalized	$ 1,196	$ 1,273	$ 1,265
Cash payments for income taxes, net of refunds	$ 377	$ 487	$ 388
SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES:			
Assets acquired through capital lease and other liabilities	$ —	$ 5	$ 18
Dividends declared but not yet paid	$ 86	$ 174	$ 135
Conversion of Alto Maipo loans and accounts payable into equity (see Note 14—*Equity*)	$ 279	$ —	$ —
Return Share Transfer Payment due (see Note 22—*Held-for-Sale Businesses and Dispositions*)	$ 75	$ —	$ —

See Accompanying Notes to Consolidated Financial Statements.

1. GENERAL AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The AES Corporation is a holding company (the "Parent Company") that, through its subsidiaries and affiliates, (collectively, "AES" or "the Company") operates a geographically diversified portfolio of electricity generation and distribution businesses. Generally, the liabilities of individual operating entities are non-recourse to the Parent Company and are isolated to the operating entities. Most of our operating entities are structured as limited liability entities, which limit the liability of shareholders. The structure is generally the same regardless of whether a subsidiary is consolidated under a voting or variable interest model. The preparation of these consolidated financial statements is in conformity with accounting principles generally accepted in the United States of America ("US GAAP").

PRINCIPLES OF CONSOLIDATION — The consolidated financial statements of the Company include the accounts of The AES Corporation and its controlled subsidiaries. Furthermore, VIEs in which the Company has an ownership interest and is the primary beneficiary, thus controlling the VIE, have been consolidated. Intercompany transactions and balances are eliminated in consolidation. Investments in entities where the Company has the ability to exercise significant influence, but not control, are accounted for using the equity method of accounting.

NONCONTROLLING INTERESTS — Noncontrolling interests are classified as a separate component of equity in the Consolidated Balance Sheets and Consolidated Statements of Changes in Equity. Additionally, net income and comprehensive income attributable to noncontrolling interests are reflected separately from consolidated net income and comprehensive income on the Consolidated Statements of Operations and Consolidated Statements of Changes in Equity. Any change in ownership of a subsidiary while the controlling financial interest is retained is accounted for as an equity transaction between the controlling and noncontrolling interests (unless the transaction qualifies as a sale of in-substance real estate). Losses continue to be attributed to the noncontrolling interests, even when the noncontrolling interests' basis has been reduced to zero.

Equity securities with redemption features that are not solely within the control of the issuer are classified outside of permanent equity. Generally, initial measurement will be at fair value. Subsequent measurement and classification vary depending on whether the instrument is probable of becoming redeemable. Where the equity instrument is not probable of becoming redeemable subsequent allocation of income and dividends is classified in permanent equity. For those securities where it is probable that the instrument will become redeemable or that are currently redeemable, AES recognizes changes in the fair value at each accounting period against retained earnings subject to the floor of the initial fair value. Further, the allocation of income and dividends, as well as the adjustment to fair value, is classified outside permanent equity. Amounts that are mandatory 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 our results of operations.

The Company utilizes the cumulative earning 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 each fair value and the carrying amount of the corresponding asset or liability in the financial statements of the investee. The AES share of the amortization of the basis difference is recognized in our net equity in earnings of affiliates over the life of the asset or liability.

The Company periodically assesses if impairment indicators exist at our equity method investments. When an impairment is observed, any excess of the carrying amount over its estimated fair value is recognized as impairment expense when the loss in value is deemed other-than-temporary and included in *Other non-operating expense* in the Consolidated Statements of Operations.

ALLOCATION OF EARNINGS — Certain of the Company's businesses are subject to profit-sharing arrangements where the allocation of cash distributions and the sharing of tax benefits are not based on fixed ownership percentages. These arrangements exist for certain 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 hypothetical liquidation at book value ("HLBV") method when it is a reasonable approximation of the profit-sharing arrangement. The HLBV method calculates the proceeds that would be attributable to each partner based on the liquidation provisions of the respective operating partnership agreement if the partnership was to be liquidated at book value at the balance sheet date. Each partner's share of income in the period is equal to the change in the amount of net equity they are legally able to claim based on a hypothetical liquidation of the entity at the end of a reporting period compared to the beginning of that period, adjusted for any capital transactions.

The HLBV method is used both to allocate the equity earnings attributable to AES when the Company accounts for the renewable business as an equity method investment and to calculate the earnings attributable to noncontrolling interest when the business is consolidated by AES. Where, prior to the commencement of operating activities for a respective renewable energy facility, HLBV results in an immediate decrease in the hypothetical liquidation proceeds attributable to the tax equity investor due to the recognition of ITCs or other adjustments as required by the U.S. Internal Revenue Code, the Company records the impact (sometimes referred to as the 'Day one gain') to income in the same period.

USE OF ESTIMATES — US 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: the carrying amount and 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 in a business combination; the measurement of equity method investments or noncontrolling interest using the HLBV method for certain renewable generation partnerships; the determination of whether a sale of noncontrolling interests is considered to be a sale of in-substance real estate (as opposed to an equity transaction); pension liabilities; environmental liabilities; the impact of U.S. tax reform; and potential litigation claims and settlements.

HELD-FOR-SALE BUSINESSES — A business classified as held-for-sale is reflected on the balance sheet at the lower of its carrying amount or estimated fair value less cost to sell. A loss is recognized if the carrying amount of the business exceeds its estimated fair value less cost to sell. This loss is limited to the carrying value of long lived assets until the completion of the sale, at which point, any additional loss is recognized. If the fair value of the business subsequently exceeds the carrying amount while the business is still held-for-sale, any impairment expense previously recognized will be reversed up to the lower of the previously recognized expense or the subsequent excess.

Assets and liabilities related to a business classified as held-for-sale are segregated in the current balance sheet in the period in which the business is classified as held-for-sale. Assets and liabilities of held-for-sale businesses are classified as current when they are expected to be disposed of within twelve months. Transactions between the business held-for-sale and businesses that are expected to continue to exist after the disposal are not eliminated to appropriately reflect the continuing operations and balances held-for-sale. See Note 22—*Held-for-Sale Businesses 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 statement of operations and balance sheet 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 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 cost to sell, including gains or losses associated with noncontrolling interests upon completion of the disposal transaction. See Note 21—*Discontinued Operations* for further information.

RECLASSIFICATIONS — To comply with newly adopted accounting standards, certain prior period amounts in the consolidated financial statements have been reclassified to conform to the current presentation. The recognition of excess tax benefits related to share-based payments resulted in a reclassification from *Deferred income taxes* to *Retained earnings* in the Consolidated Balance Sheet for the year ended December 31, 2016. See further detail in the new accounting pronouncements discussion.

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 assets (noncurrent)*; derivative assets, included in *Other current assets* and *Other assets (noncurrent)*; and, derivative liabilities, included in *Accrued and other liabilities (current)* and *Other long-term liabilities*. The Company applies the fair value measurement guidance to nonfinancial assets and liabilities upon the acquisition of a business or in conjunction with the measurement of an asset retirement obligation or a potential impairment loss on an asset group 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.

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

Short-term investments consist of marketable equity securities and debt securities with original maturities in excess of three months with remaining maturities of less than one year. Marketable debt securities where the Company has both the positive intent and ability to hold to maturity are classified as held-to-maturity and are carried at amortized cost. Remaining marketable securities are classified as available-for-sale or trading and are carried at fair value.

Available-for-sale and trading investment's unrealized gains or losses are reflected in AOCL, a separate component of equity, and the Consolidated Statements of Operations, respectively .. 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 DOUBTFUL ACCOUNTS — 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 doubtful accounts for the estimated uncollectible amount as appropriate. 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 market 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 capital leases and intangible assets subject to amortization (i.e., finite-lived intangible assets).

Property, plant and equipment — Property, plant and equipment are stated at cost, net of accumulated depreciation. The cost of renewals and improvements that extend the useful life of property, plant and equipment are capitalized.

Construction progress payments, engineering costs, insurance costs, salaries, interest and other costs directly relating to construction in progress are capitalized during the construction period, provided the completion of the construction project is deemed probable, or expensed at the time construction completion is determined to no longer be probable. The continued capitalization of such costs is subject to risks related to successful completion, including those related to government approvals, site identification, financing, construction permitting and contract compliance. Construction-in-progress balances are transferred to electric generation and distribution assets when an asset group is ready for its intended use. Government subsidies, liquidated damages recovered for construction delays, and income tax credits 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.

The Company's Brazilian subsidiaries operate under concession contracts. Certain estimates are utilized to determine depreciation expense for the Brazilian subsidiaries, including the useful lives of the property, plant and equipment and the amounts to be recovered at the end of the concession contract. The amounts to be recovered under these concession contracts are based on estimates that are inherently uncertain and actual amounts recovered may differ from those estimates. These concession contracts are not within the scope of ASC 853—*Service Concession Arrangements*.

Intangible Assets Subject to Amortization — Finite-lived intangible assets are amortized over their useful lives which range from 3 – 50 years. 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.

SERVICE CONCESSION ASSETS — Service concession assets are stated at cost, net of accumulated amortization, in accordance with ASC 853. Service concession assets represent the cost of all infrastructure to be transferred to the public-sector entity grantors at the end of the concession. These costs primarily represent construction progress payments, engineering costs, insurance costs, salaries, interest and other costs directly relating to construction of the service concession infrastructure. Government subsidies, liquidated damages recovered for construction delays and income tax credits are recorded as a reduction to Service Concession Assets. Service concession assets are amortized and recognized in earnings as a cost of goods sold as infrastructure construction revenue is recognized. Services provided under concession arrangements are recognized on a straight line basis.

DEBT ISSUANCE COSTS — Costs incurred in connection with the issuance of long-term debt are deferred and presented as a direct reduction from the face amount of that debt and amortized over the related financing period using the effective interest method. Debt issuance costs related to a line-of-credit or revolving credit facility are deferred and presented as an asset and amortized over the related financing period. Make-whole payments in connection with early debt retirements are classified as cash flows used in financing activities.

GOODWILL AND INDEFINITE-LIVED INTANGIBLE ASSETS — The Company evaluates goodwill and indefinite-lived intangible assets for impairment on an annual basis and whenever events or changes in circumstances necessitate an evaluation for impairment. The Company's annual impairment testing date is October first.

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 two-step quantitative test. If goodwill is determined to be impaired, the fair value of individual assets and liabilities is determined to compute the implied fair value of goodwill. If the carrying amount of goodwill exceeds its implied fair value, the excess is recognized as an impairment loss up to the carrying amount of the goodwill.

Indefinite-Lived Intangible Assets — The Company's indefinite-lived intangible assets primarily include land-use rights and water rights. Indefinite-lived Intangible Assets are evaluated for impairment either under the qualitative assessment option or the two-step quantitative 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. Other accrued liabilities include items such as income taxes, regulatory liabilities, legal contingencies and employee-related costs, including payroll, benefits and related taxes.

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 Statement of Operations within *Interest Income*. Regulatory liabilities generally represent obligations to refund customers. Management continually assesses whether regulatory assets are probable of future recovery and regulatory liabilities are probable of future payment by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities, and the status of any pending or potential deregulation legislation. If future recovery of costs previously deferred ceases to be probable, the related regulatory assets are written off and recognized in income from continuing operations.

PENSION AND OTHER POSTRETIREMENT PLANS — The Company recognizes in its Consolidated Balance Sheets an asset or liability reflecting the funded status of pension and other postretirement plans with current-year changes in actuarial gains or losses recognized in AOCL, except for those plans at certain of the Company's regulated utilities that can recover portions of their pension and postretirement obligations through future rates. All plan assets are recorded at fair value. AES follows the measurement date provisions of the accounting guidance, which require a year-end measurement date of plan assets and obligations for all defined benefit plans.

INCOME TAXES — Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax 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'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 not yet determined its accounting policy election, as outlined by SAB 118, with respect to the new GILTI provisions of U.S. tax reform, applicable from January 1, 2018. See Note 20—*Income Taxes* for additional discussion regarding the U.S. tax reform.

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 from utilities is classified as regulated in the Consolidated Statements of Operations. Revenue from the sale of energy is recognized in the period during which the sale occurs. 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. Differences between actual and estimated unbilled revenue are usually immaterial. The Company has businesses where it sells and purchases power to and from ISOs and RTOs. In those instances, the Company accounts for these transactions on a net hourly basis because the transactions are settled on a net hourly basis.

Revenue from generation businesses is classified as non-regulated in the Consolidated Statements of Operations. Revenue is recognized based upon output delivered and capacity provided, at rates as specified under contract terms or prevailing market rates. Certain of the Company's PPAs meet the definition of an operating lease or contain similar arrangements. Typically, minimum lease payments from such PPAs are recognized as revenue on a straight-line basis over the lease term whereas contingent rentals are recognized when earned. Revenue is recorded net of any taxes assessed on and collected from customers, which are remitted to the governmental authorities.

SHARE-BASED COMPENSATION — The Company grants share-based compensation in the form of stock options, restricted stock units, performance stock units, and performance cash units. 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 the Company's fair value policy and Note 4—*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 contain either a derivative or an embedded derivative requiring separate valuation and accounting. Generally, these agreements do not meet the definition of a derivative, often due to the inability to be net settled. On a quarterly basis, we evaluate the markets for commodities to be delivered under these agreements to determine if facts and circumstances have changed such that the agreements could be net settled and meet the definition of a derivative.

The Company typically designates its derivative instruments as cash flow hedges if they meet the criteria specified in ASC 815, *Derivatives and Hedging*. The Company enters into interest rate swap agreements in order to hedge the variability of expected future cash interest payments. Foreign currency contracts are used to reduce risks arising from the change in fair value of certain foreign currency denominated assets and liabilities. The objective of these practices is to minimize the impact of foreign currency fluctuations on operating results. The Company also enters into commodity contracts to economically hedge price variability inherent in electricity sales arrangements. The objectives of the commodity contracts are to minimize the impact of variability in spot electricity prices and stabilize estimated revenue streams. The Company does not use derivative instruments for speculative purposes.

For our hedges, changes in fair value that are considered highly effective are deferred in AOCL and are recognized into earnings as the hedged transactions affect earnings. Any ineffectiveness is recognized in earnings immediately. If a derivative is no longer highly effective, hedge accounting will be discontinued prospectively. For cash flow hedges of forecasted transactions, AES estimates the future cash flows of the forecasted transactions and evaluates the probability of the occurrence and timing of such transactions.

Changes in the fair value of derivatives not designated and qualifying as cash flow 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. The Company has elected not to offset net derivative positions in the financial statements.

NEW ACCOUNTING PRONOUNCEMENTS — The following table provides a brief description of recent accounting pronouncements that had and/or could have a material impact on the Company’s consolidated financial statements. 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 Adopted

ASU Number and Name	Description	Date of Adoption	Effect on the financial statements upon adoption
2016-09, Compensation — Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting	The standard simplifies the following aspects of accounting for share-based payments awards: accounting for income taxes, classification of excess tax benefits on the statement of cash flows, forfeitures, statutory tax withholding requirements, classification of awards as either equity or liabilities and classification of employee taxes paid on statement of cash flows when an employer withholds shares for tax-withholding purposes. Transition method: The recognition of excess tax benefits and tax deficiencies arising from vesting or settlement were applied retrospectively. The elimination of the requirement that excess tax benefits be realized before they are recognized was adopted on a modified retrospective basis.	January 1, 2017	The recognition of excess tax benefits in the provision for income taxes in the period when the awards vest or are settled, rather than in paid-in-capital in the period when the excess tax benefits are realized, resulted in a decrease of $31 million to deferred tax liabilities, offset by an increase to retained earnings.

New Accounting Standards Issued But Not Yet Effective

ASU Number and Name	Description	Date of Adoption	Effect on the financial statements upon adoption
2018-02, Income Statement — Reporting Comprehensive Income (Topic 220), Reclassification of Certain Tax Effects from AOCI	This amendment allows a reclassification of the stranded tax effects resulting from the implementation of the Tax Cuts and Jobs Act from AOCI to retained earnings. Because this amendment only relates to the reclassification of the income tax effects of the Tax Cuts and Jobs Act, the underlying guidance that requires that the effect of a change in tax laws or rates be included in income from continuing operations is not affected.	January 1, 2019. Early adoption is permitted.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.
2017-12, Derivatives and Hedging (Topic 815): Targeted improvements to Accounting for Hedging Activities	The standard updates the hedge accounting model to expand the ability to hedge nonfinancial and financial risk components, reduce complexity, and ease certain documentation and assessment requirements. When facts and circumstances are the same as at the previous quantitative test, a subsequent quantitative effectiveness test is not required. The standard also eliminates the requirement to separately measure and report hedge ineffectiveness. For cash flow hedges, this means that the entire change in the fair value of a hedging instrument will be recorded in other comprehensive income and amounts deferred will be reclassified to earnings in the same income statement line as the hedged item. Transition method: modified retrospective with the cumulative effect adjustment recorded to the opening balance of retained earnings as of the initial application date. Prospective for presentation and disclosures.	January 1, 2019. Early adoption is permitted.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.
2017-11, Earnings Per Share (Topic 260); Distinguishing Liabilities from Equity (Topic 480); Derivatives and Hedging (Topic 815): Accounting for Certain Financial Instruments and Certain Mandatorily Redeemable Noncontrolling Interests	Part 1 of this standard changes the classification of certain equity-linked financial instruments when assessing whether the instrument is indexed to an entity's own stock. Transition method: retrospective.	January 1, 2019. Early adoption is permitted.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.
2017-08, Receivables — Nonrefundable Fees and Other Costs (Subtopic 310-20): Premium Amortization on Purchased Callable Debt Securities	This standard shortens the period of amortization for the premium on certain callable debt securities to the earliest call date. Transition method: modified retrospective.	January 1, 2019. Early adoption is permitted.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.
2017-05, Other Income — Gains and Losses from the Derecognition of Nonfinancial Assets (Topic 610-20)	This standard clarifies the scope and application of ASC 610-20 on the sale, transfer, and derecognition of nonfinancial assets and in substance nonfinancial assets to non-customers, including partial sales. It also clarifies that the derecognition of businesses is under scope of ASC 810. The standard must be adopted concurrently with ASC 606, however an entity will not have to apply the same transition method as ASC 606. Transition method: full or modified retrospective. Under a modified retrospective approach, the guidance shall be applied to all contracts that are not completed as of the initial application date (January 1, 2018). The Company has identified contracts executed during Q4 2017 that would not be completed as of this date and is in the process of assessing those under the new standard. However, no adjustment is expected as of the initial application date.	January 1, 2018. Early adoption is permitted only as of January 1, 2017.	The Company does not expect any impact on its consolidated financial statements upon adoption of the standard, will adopt the standard on January 1, 2018, and plans to use the modified retrospective approach.

2017-04, Intangibles — Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment	This standard simplifies the accounting for goodwill impairment by removing the requirement to calculate the implied fair value. Instead, it requires that an entity records an impairment charge based on the excess of a reporting unit's carrying amount over its fair value. Transition method: prospective.	January 1, 2020. Early adoption is permitted as of January 1, 2017.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.
2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business	The standard requires an entity to first evaluate whether substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets, and if that threshold is met, the set is not a business. As a second step, to be considered a business at least one substantive process should exist. The revised definition of a business will reduce the number of transactions that are accounted for as business combinations. Transition Method: prospective.	January 1, 2018. Early adoption is permitted.	This revised definition will reduce the number of transactions that are accounted for as a business, therefore, acquisitions and disposition would fall under a different accounting model.
2016-18, Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)	This standard requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. Transition method: retrospective.	January 1, 2018. Early adoption is permitted.	The Company has performed a preliminary evaluation and expects an increase in cash provided by operating activities of approximately $5 million for 2017 and 2016 and a decrease of $5 million in 2015. Net cash used in investing activities are expected to decrease by approximately $150 million and $230 million for 2017 and 2015, respectively, with an increase of $10 million expected for 2016.
2016-13, Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments	The standard updates the impairment model for financial assets measured at amortized cost. For trade and other receivables, held-to-maturity debt securities, loans and other instruments, entities will be required to use a new forward-looking "expected loss" model that generally will result in the earlier recognition of allowance for losses. For available-for-sale debt securities with unrealized losses, entities will measure credit losses as it is done today, except that the losses will be recognized as an allowance rather than a reduction in the amortized cost of the securities. Transition method: various.	January 1, 2020. Early adoption is permitted only as of January 1, 2019.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.
2016-02, 2018-01, Leases (Topic 842)	See discussion of the ASU below.	January 1, 2019. Early adoption is permitted.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements and intends to adopt the standard as of January 1, 2019.
2014-09, 2015-14, 2016-08, 2016-10, 2016-12, 2016-20, 2017-10, 2017-13, Revenue from Contracts with Customers (Topic 606)	See discussion of the ASU below.	January 1, 2018. Early adoption is permitted only as of January 1, 2017.	The Company will adopt the standard on January 1, 2018; see below for the evaluation of the impact of its adoption on the consolidated financial statements.

ASU 2014-09 and its subsequent corresponding updates provides the principles an entity must apply to measure and recognize revenue. The core principle is that an entity shall recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. Amendments to the standard were issued that provide further clarification of the principle and to provide certain transition expedients. The standard will replace most existing revenue recognition guidance in GAAP.

The standard requires retrospective application and allows either a full retrospective adoption in which all of the periods are presented under the new standard or a modified retrospective approach in which the cumulative effect of initially applying the guidance is recognized at the date of initial application.

In 2016, the Company established a cross-functional implementation team and is in the process of evaluating changes to our business processes, systems and controls to support recognition and disclosure under the new standard. At this time, we do not expect any significant impact on our financial systems or a material change to controls as a result of the implementation of the new revenue recognition standard.

Given the complexity and diversity of our non-regulated arrangements, the Company is assessing the standard on a contract by contract basis applying the interpretations reached during 2017 on key issues. These include the application of the practical expedient for measuring progress toward satisfaction of a performance obligation, when variable quantities would be considered variable consideration versus an option to acquire additional goods and services, how to allocate variable consideration to one or more, but not all, distinct goods or services promised in a series of distinct goods or services that forms part of a single performance obligation. Additionally, the Company has been working on the application of the standard to contracts that are under the scope of Service Concession Arrangements (Topic 853) and assessing the gross versus net presentation for spot energy sales and purchases. Through this assessment, the Company to date has identified limited situations where revenue recognized under ASC 606 could differ from that recognized under ASC 605 and where the presentation of sales to and purchases from the energy spot markets will change.

The cumulative effect of applying the new standard that the Company expects to recognize at the date of initial application is mainly related to a contract under the scope of Topic 853. For this contract, the Company has concluded that revenue recognized since the inception of the agreement would be higher through January 1, 2018 under ASC 606. This will result in a decrease to the opening balance of *Accumulated deficit* of approximately $60 million and *Accumulated other comprehensive loss* of approximately $20 million, and an increase to the opening balance of *Noncontrolling interest* of approximately $80 million. Additionally, the application of ASC 606 will result in a reclassification from *Service concession assets* to *Other noncurrent assets* of $1,360 million. Given the limited impact, the Company expects to use the modified retrospective approach.

We are continuing to work with various non-authoritative industry groups, and monitoring the FASB and Transition Resource Group activity.

ASU 2016-02 and its subsequent corresponding updates require lessees to recognize assets and liabilities for most leases but recognize expenses in a manner similar to today’s accounting. For Lessors, the guidance modifies the lease classification criteria and the accounting for sales-type and direct financing leases. The guidance also eliminates today’s real estate-specific provisions.

The standard must be adopted using a modified retrospective approach at the beginning of the earliest comparative period presented in the financial statements (January 1, 2017). The FASB proposed amending the standard to give another option for transition. The proposed transition method would allow entities to not apply the new lease standard in the comparative periods presented in their financial statements in the year of adoption. Under the proposed transition method, the entity would apply the transition provisions on January 1, 2019 (i.e., the effective date). At transition, lesses and lessors are permitted to make an election to apply a package of practical expedients that allow them not to reassess: (1) whether any expired or existing contracts are or contain leases, (2) lease classification for any expired or existing leases, and (3) whether initial direct costs for any expired or existing leases qualify for capitalization under ASC 842. These three practical expedients must be elected as a package and must be consistently applied to all leases. Furthermore, entities are also permitted to make an election to use hindsight when determining lease term and lessees can elect to use hindsight when assessing the impairment of right-of-use assets.

The Company has established a task force focused on the identification of contracts that would be under the scope of the new standard and on the assessment and measurement of the right-of-use asset and related liability. Additionally, the implementation team has been working on the identification and selection of a lease accounting system that would support the implementation and the subsequent accounting. The implementation team is in the process of evaluating changes to our business processes, systems and controls to support recognition and disclosure under the new standard.

As the Company has preliminarily concluded that at transition it would be using the package of practical expedients, the main impact expected as of the effective date is the recognition of the right to use asset and the related liability in the financial statements for all those contracts that contain a lease and for which the Company is the lessee. However, income statement presentation and the expense recognition pattern will not change.

Under ASC 842, it is expected that fewer contracts will contain a lease. However, due to the elimination of today's real estate-specific guidance and changes to certain lessor classification criteria, more leases will qualify as sales-type leases and direct financing leases. Under these two models, a lessor will derecognize the asset and will recognize a lease receivable. According to ASC 842, the lease receivable does not include variable payments that depend on the use of the asset (e.g. Mwh produced by a facility). Therefore, the lease receivable could be lower than the carrying amount of the underlying asset at lease commencement, In such circumstances, the difference between the initially recognized lease receivable and the carrying amount of the underlying asset is recognized as a selling loss at lease commencement. The Company is assessing how this guidance will apply to new renewable contracts executed or modified after the effective date where all the payments are contingent on the level of production and is also evaluating the related impact to HLBV accounting.

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,	2017	2016
Fuel and other raw materials	$ 284	$ 302
Spare parts and supplies	278	320
Total	$ 562	$ 622

3. PROPERTY, PLANT AND EQUIPMENT

The following table summarizes the components of the electric generation and distribution assets and other property, plant and equipment (in millions) with their estimated useful lives (in years). The amounts are stated net of all prior asset impairment losses recognized.

		December 31,	
	Estimated Useful Life	2017	2016
Electric generation and distribution facilities	8 - 40	$ 21,529	$ 22,337
Other buildings	5 - 71	1,971	1,906
Furniture, fixtures and equipment	2 - 32	284	303
Other	5 - 44	335	365
Total electric generation and distribution assets and other		24,119	24,911
Accumulated depreciation		(7,942)	(7,919)
Net electric generation and distribution assets and other		$ 16,177	$ 16,992

The following table summarizes depreciation expense (including the amortization of assets recorded under capital 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,	2017	2016	2015
Depreciation expense	$ 1,005	$ 1,002	$ 958
Interest capitalized during development and construction	139	118	84

Property, plant and equipment, net of accumulated depreciation, of $10 billion was mortgaged, pledged or subject to liens as of December 31, 2017 and 2016, including assets classified as held-for-sale.

The following table summarizes regulated and non-regulated generation and distribution property, plant and equipment and accumulated depreciation as of the dates indicated (in millions):

December 31,	2017	2016
Regulated generation, distribution assets and other, gross	$ 8,093	$ 7,815
Regulated accumulated depreciation	(3,357)	(3,299)
Regulated generation, distribution assets and other, net	4,736	4,516
Non-regulated generation, distribution assets and other, gross	16,026	17,096
Non-regulated accumulated depreciation	(4,585)	(4,620)
Non-regulated generation, distribution assets and other, net	11,441	12,476
Net electric generation, distribution assets and other	$ 16,177	$ 16,992

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

	2017	2016
Balance at January 1	$ 357	$ 247
Additional liabilities incurred	1	12
Liabilities settled	(21)	(4)
Accretion expense	16	15
Change in estimated cash flows	25	86
Other	(10)	1
Balance at December 31	$ 368	$ 357

The Company's asset retirement obligations primarily include active ash landfills, water treatment basins and the removal or dismantlement of certain plants and equipment. The $25 million increase in estimated cash flows for 2017 is primarily related to the legal obligations for the demolition of the Huntington Beach Units in connection with the Southland re-powering project.

4. 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. By virtue of these amounts being estimates and based on hypothetical transactions to sell assets or transfer liabilities, the use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts.

Valuation Techniques — The fair value measurement accounting guidance describes three main approaches to measuring the fair value of assets and liabilities: (1) market approach, (2) income approach and (3) cost approach. The market approach uses prices and other relevant information generated from market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to convert future amounts to a single present value amount. The measurement is based on current market expectations of the return on those future amounts. The cost approach is based on the amount that would currently be required to replace an asset. The Company measures its investments and derivatives at fair value on a recurring basis. Additionally, in connection with annual or event-driven impairment evaluations, certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis. These include long-lived tangible assets (i.e., property, plant and equipment), goodwill and intangible assets (e.g., sales concessions, land use rights and water rights, etc.). In general, the Company determines the fair value of investments and derivatives using the market approach and the income approach, respectively. In the nonrecurring measurements of nonfinancial assets and liabilities, all three approaches are considered; however, the value estimated under the income approach is often the most representative of fair value.

Investments — The Company's investments measured at fair value generally consist of marketable debt and equity securities. Equity securities are either measured at fair value using quoted market prices or based on comparisons to market data obtained for similar assets. Debt securities primarily consist of unsecured debentures and certificates of deposit held by our Brazilian subsidiaries. Returns and pricing on these instruments are generally indexed to the market interest rates in Brazil. Debt securities are measured at fair value based on comparisons to market data obtained for similar assets.

Derivatives — Derivatives are measured at fair value using quoted market prices or the income approach utilizing volatilities, spot and forward benchmark interest rates (such as LIBOR and EURIBOR), foreign exchange rates, credit data, and commodity prices, 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. 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. Similarly, 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 (based on applying a standard industry model to historical financial information and then considering other relevant information) and spreads of comparably rated entities or the respective country's debt spreads are used as a proxy. All derivative instruments are analyzed individually and are subject to unique risk exposures.

The fair value hierarchy of an asset or a liability is based on the level of significance of the input assumptions. An input assumption is considered significant if it affects the fair value by at least 10%. Assets and liabilities are classified as Level 3 when the use of unobservable inputs is significant. When the use of unobservable inputs is insignificant, assets and liabilities are classified as Level 2. Transfers between Level 3 and Level 2 are determined as of the end of the reporting period and result from changes in significance of unobservable inputs used to calculate the CVA.

Debt — Recourse and non-recourse debt are carried at amortized cost. The fair value of recourse debt is estimated based on quoted market prices. The fair value of non-recourse debt is estimated based upon interest rates and other features of the loan. In general, the carrying amount of variable rate debt is a close approximation of its fair value. For fixed rate loans, the fair value is estimated using quoted market prices or discounted cash flow ("DCF") analyses. The fair value of recourse and non-recourse debt excludes accrued interest at the valuation date. The fair value was determined using available market information as of December 31, 2017. The Company is not aware of any factors that would significantly affect the fair value amounts subsequent to December 31, 2017.

Nonrecurring measurements — For nonrecurring measurements derived using the income approach, fair value is generally determined using valuation models based on the principles of DCF. The income approach is most often used in the impairment evaluation of long-lived tangible assets, equity method investments, goodwill, and intangible assets. Where the use of market observable data is limited or not available for certain input assumptions, the Company develops its own estimates using a variety of techniques such as regression analysis and extrapolations. Depending on the complexity of a valuation, an independent valuation firm may be engaged to assist management in the valuation process.

For nonrecurring measurements derived using the market approach, recent market transactions involving the sale of identical or similar assets are considered. The use of this approach is limited because it is often difficult to identify sale transactions of identical or similar assets. This approach is used in impairment evaluations of certain intangible assets. Otherwise, it is used to corroborate the fair value determined under the income approach.

For nonrecurring measurements derived using the cost approach, fair value is typically based upon a replacement cost approach. This approach involves a considerable amount of judgment, which is why its use is limited to the measurement of long-lived tangible assets. Like the market approach, this approach is also used to corroborate the fair value determined under the income approach.

Fair Value Considerations — In determining fair value, the Company considers the source of observable market data inputs, liquidity of the instrument, the credit risk of the counterparty and the risk of the Company's or its counterparty's nonperformance. The conditions and criteria used to assess these factors are:

Sources of market assumptions — The Company derives most of its market assumptions from market efficient data sources (e.g., Bloomberg and Reuters). To determine fair value, where market data is not readily available, management uses comparable market sources and empirical evidence to develop its own estimates of market assumptions.

Market liquidity — The Company evaluates market liquidity based on whether the financial or physical instrument, or the underlying asset, is traded in an active or inactive market. An active market exists if the prices are fully transparent to market participants, can be measured by market bid and ask quotes, the market has a relatively large proportion of trading volume as compared to the Company's current trading volume and the market has a significant number of market participants that will allow the market to rapidly absorb the quantity of assets traded without significantly affecting the market price. Another factor the Company considers when determining whether a market is active or inactive is the presence of government or regulatory controls over pricing that could make it difficult to establish a market-based price when entering into a transaction.

Nonperformance risk — Nonperformance risk refers to the risk that an obligation will not be fulfilled and affects the value at which a liability is transferred or an asset is sold. Nonperformance risk includes, but may not be limited to, the Company 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 and equity securities, the security classes presented are 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, 2017				December 31, 2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
AVAILABLE FOR SALE:								
Debt securities:								
Unsecured debentures	$ —	$ 207	$ —	$ 207	$ —	$ 205	$ —	$ 205
Certificates of deposit	—	153	—	153	—	260	—	260
Government debt securities	—	—	—	—	—	9	—	9
Subtotal	—	360	—	360	—	474	—	474
Equity securities:								
Mutual funds	—	52	—	52	—	48	—	48
Subtotal	—	52	—	52	—	48	—	48
Total available for sale	—	412	—	412	—	522	—	522
TRADING:								
Equity securities:								
Mutual funds	20	—	—	20	16	—	—	16
Total trading	20	—	—	20	16	—	—	16
DERIVATIVES:								
Interest rate derivatives	—	15	—	15	—	18	—	18
Cross-currency derivatives	—	29	—	29	—	4	—	4
Foreign currency derivatives	—	29	240	269	—	54	255	309
Commodity derivatives	—	30	5	35	—	38	7	45
Total derivatives — assets	—	103	245	348	—	114	262	376
TOTAL ASSETS	$ 20	$ 515	$ 245	$ 780	$ 16	$ 636	$ 262	$ 914
Liabilities								
DERIVATIVES:								
Interest rate derivatives	$ —	$ 111	$ 151	$ 262	$ —	$ 121	$ 179	$ 300
Cross-currency derivatives	—	3	—	3	—	18	—	18
Foreign currency derivatives	—	30	—	30	—	64	—	64
Commodity derivatives	—	19	1	20	—	40	2	42
Total derivatives — liabilities	—	163	152	315	—	243	181	424
TOTAL LIABILITIES	$ —	$ 163	$ 152	$ 315	$ —	$ 243	$ 181	$ 424

As of December 31, 2017, all AFS debt securities had stated maturities within one year. For the years ended December 31, 2017, 2016, and 2015, no other-than-temporary impairment of marketable securities were recognized in earnings or Other Comprehensive Income (Loss). Gains and losses on the sale of investments are determined using the specific-identification method. The following table presents gross proceeds from sale of AFS securities for the periods indicated (in millions):

Year Ended December 31,	2017	2016	2015
Gross proceeds from sales of AFS securities	$ 1,398	$ 1,726	$ 1,226

Any Level 1 derivative instruments are exchange-traded commodity futures for which the pricing is observable in active markets, and as such, these are not expected to transfer to other levels. There have been no transfers between Level 1 and Level 2.

The following tables present a reconciliation of net derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the years ended December 31, 2017 and 2016 (presented net by type of derivative in millions). Transfers between Level 3 and Level 2 are determined as of the end of the reporting period and principally result from changes in the significance of unobservable inputs used to calculate the credit valuation adjustment.

Year Ended December 31, 2017	Interest Rate	Foreign Currency	Commodity	Total
Balance at January 1	$ (179)	$ 255	$ 5	$ 81
Total realized and unrealized gains (losses):				
Included in earnings	(1)	21	1	21
Included in other comprehensive income — derivative activity	(23)	—	—	(23)
Included in regulatory liabilities	—	—	10	10
Settlements	36	(36)	(12)	(12)
Transfers of liabilities into Level 3	(4)	—	—	(4)
Transfers of liabilities out of Level 3	20	—	—	20
Balance at December 31	$ (151)	$ 240	$ 4	$ 93
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	$ 7	$ (15)	$ 1	$ (7)

Year Ended December 31, 2016	Interest Rate	Foreign Currency	Commodity	Total
Balance at January 1	$ (304)	$ 277	$ 3	$ (24)
Total realized and unrealized gains (losses):				
Included in earnings	—	31	2	33
Included in other comprehensive income — derivative activity	(36)	6	—	(30)
Included in other comprehensive income — foreign currency translation activity	3	(52)	—	(49)
Included in regulatory liabilities	—	—	11	11
Settlements	72	(22)	(11)	39
Transfers of liabilities into Level 3	(32)	—	—	(32)
Transfers of assets out of Level 3	118	15	—	133
Balance at December 31	$ (179)	$ 255	$ 5	$ 81
Total gains 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	$ 16	$ 2	$ 24

The following table summarizes the significant unobservable inputs used for the Level 3 derivative assets (liabilities) as of December 31, 2017 (in millions, except range amounts):

Type of Derivative	Fair Value	Unobservable Input	Amount or Range (Weighted Average)
Interest rate	$ (151)	Subsidiaries' credit spreads	1.9% - 5.1% (4.9%)
Foreign currency:			
Argentine peso	240	Argentine peso to U.S. dollar currency exchange rate after one year [1]	22.8 - 52.3 (36.6)
Commodity:			
Other	4		
Total	$ 93		

(1) During the year ended December 31, 2017, the Company began utilizing the interest rate differential approach to construct the remaining portion of the forward curve after one year (beyond the traded points). In previous periods, the Company used the purchasing price parity approach to construct the forward curve.

For interest rate derivatives, and foreign currency derivatives, increases (decreases) in the estimates of the Company's own credit spreads would decrease (increase) the value of the derivatives in a liability position. For foreign currency derivatives, increases (decreases) in the estimate of the above exchange rate would increase (decrease) the value of the derivative.

Nonrecurring Measurements

When evaluating impairment of long-lived assets and equity method investments, the Company measures fair value using the applicable fair value measurement guidance. Impairment expense is measured by comparing the fair value at the evaluation date to their then-latest available carrying amount. The following table summarizes major categories of assets and liabilities measured at fair value on a nonrecurring basis during the period and their level within the fair value hierarchy (in millions):

Year Ended December 31, 2017	Measurement Date	Carrying Amount [1]	Fair Value			Pre-tax Loss
Assets			Level 1	Level 2	Level 3	
Long-lived assets held and used: [2]						
Laurel Mountain	12/31/2017	$ 154	$ —	$ —	$ 33	$ 121
Kilroot	12/31/2017	69	—	—	20	37
DPL	02/28/2017	77	—	—	11	66
Other	Various	18	—	—	—	18
Dispositions and held-for-sale businesses: [3]						
DPL Peaker Assets	12/31/2017	346	—	237	—	109
Kazakhstan Hydroelectric [4]	06/30/2017	190	—	92	—	92
Kazakhstan CHPs	03/31/2017	171	—	29	—	94

Year Ended December 31, 2016 Assets	Measurement Date	Carrying Amount (1)	Fair Value Level 1	Fair Value Level 2	Fair Value Level 3	Pre-tax Loss
Long-lived assets held and used: (2)						
DPL	12/31/2016	$ 787	$ —	$ 60	$ 103	$ 624
Buffalo Gap I	08/31/2016	113	—	—	36	77
DPL	06/30/2016	324	—	—	89	235
Buffalo Gap II	03/31/2016	251	—	—	92	159
Discontinued operations: (3)						
Sul	06/30/2016	1,581	—	470	—	783

(1) Represents the carrying values at the dates of measurement, before fair value adjustment.
(2) See Note 19—*Asset Impairment Expense* for further information.
(3) Per the Company's policy, pre-tax loss is limited to the impairment of long-lived assets. Any additional loss will be recognized on completion of the sale. Upon disposal of Sul, we incurred an additional pre-tax loss on sale of $602 million. See Note 21—*Discontinued Operations* and Note 22—*Held-for-Sale Businesses and Dispositions* for further information.
(4) Per the Company's policy, pre-tax loss is limited to the impairment of long-lived assets. Any additional loss will be recognized on completion of the sale. Upon disposal of Kazakhstan HPPs, we incurred an additional pre-tax loss on disposal of $33 million. See Note 19—*Asset Impairment Expense* and Note 22—*Held-for-Sale Businesses and Dispositions* for further information.

The following table summarizes the significant unobservable inputs used in the Level 3 measurement of long-lived assets held and used measured on a nonrecurring basis during the year ended December 31, 2017 (in millions, except range amounts):

December 31, 2017	Fair Value	Valuation Technique	Unobservable Input	Range (Weighted Average)
Long-lived assets held and used:				
Laurel Mountain	$ 33	Discounted cash flow	Annual revenue growth	-30% to 2% (0%)
			Pre-tax operating margin (through remaining life)	61% to 73% (64%)
			Weighted-average cost of capital	9%
Kilroot	20	Discounted cash flow	Annual revenue growth	-85% to 17% (-16%)
			Annual pre-tax operating margin	-32% to 28% (6%)
			Weighted-average cost of capital	8%
DPL	11	Discounted cash flow	Pre-tax operating margin (through	10% to 22% (15%)
			Weighted-average cost of capital	7%
Total	$ 64			

Financial Instruments not Measured at Fair Value in the Consolidated Balance Sheets

The following table presents (in millions) the carrying amount, fair value and fair value hierarchy of the Company's financial assets and liabilities that are not measured at fair value in the Consolidated Balance Sheets as of the periods indicated, but for which fair value is disclosed.

		December 31, 2017 Carrying Amount	Fair Value Total	Level 1	Level 2	Level 3
Assets:	Accounts receivable — noncurrent (1)	$ 163	$ 217	$ —	$ 6	$ 211
Liabilities:	Non-recourse debt	15,340	15,890	—	13,350	2,540
	Recourse debt	4,630	4,920	—	4,920	—

		December 31, 2016 Carrying Amount	Fair Value Total	Level 1	Level 2	Level 3
Assets:	Accounts receivable — noncurrent (1)	$ 232	$ 342	$ —	$ 20	$ 322
Liabilities:	Non-recourse debt	14,783	15,185	—	14,140	1,045
	Recourse debt	4,671	4,899	—	4,899	—

(1) These amounts primarily relate to amounts due from CAMMESA, the administrator of the wholesale electricity market in Argentina, and are included in *Other noncurrent assets* in the accompanying Consolidated Balance Sheets. The fair value and carrying amount of these receivables exclude VAT of $31 million and $24 million as of December 31, 2017 and 2016, respectively.

5. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Volume of Activity — The following table presents the Company's maximum notional (in millions) over the remaining contractual period by type of derivative as of December 31, 2017, regardless of whether they are in qualifying cash flow hedging relationships, and the dates through which the maturities for each type of derivative range:

Derivatives	Maximum Notional Translated to USD	Latest Maturity
Interest Rate (LIBOR and EURIBOR)	$ 4,481	2036
Cross-Currency Swaps (Chilean Unidad de Fomento and Chilean Peso)	410	2029
Foreign Currency:		
Argentine Peso	187	2026
Chilean Peso	410	2020
Colombian Peso	305	2019
Others, primarily with weighted average remaining maturities of a year or less	303	2020

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

Fair Value	December 31, 2017			December 31, 2016		
Assets	Designated	Not Designated	Total	Designated	Not Designated	Total
Interest rate derivatives	$ 15	$ —	$ 15	$ 18	$ —	$ 18
Cross-currency derivatives	29	—	29	4	—	4
Foreign currency derivatives	8	261	269	9	300	309
Commodity derivatives	5	30	35	20	25	45
Total assets	$ 57	$ 291	$ 348	$ 51	$ 325	$ 376
Liabilities						
Interest rate derivatives	$ 125	$ 137	$ 262	$ 295	$ 5	$ 300
Cross-currency derivatives	3	—	3	18	—	18
Foreign currency derivatives	1	29	30	19	45	64
Commodity derivatives	9	11	20	26	16	42
Total liabilities	$ 138	$ 177	$ 315	$ 358	$ 66	$ 424

	December 31, 2017		December 31, 2016	
Fair Value	Assets	Liabilities	Assets	Liabilities
Current	$ 84	$ 211	$ 99	$ 155
Noncurrent	264	104	277	269
Total	$ 348	$ 315	$ 376	$ 424

Credit Risk-Related Contingent Features [1]	December 31, 2017	December 31, 2016
Present value of liabilities subject to collateralization	$ 15	$ 41
Cash collateral held by third parties or in escrow	9	18

(1) Based on the credit rating of certain subsidiaries

Earnings and Other Comprehensive Income (Loss) — The following table presents (in millions) the pre-tax gains (losses) recognized in AOCL and earnings related to all derivative instruments for the periods indicated:

	Years Ended December 31,		
	2017	2016	2015
Effective portion of cash flow hedges			
Gains (losses) recognized in AOCL			
Interest rate derivatives	$ (66)	$ (35)	$ (103)
Cross-currency derivatives	31	21	(20)
Foreign currency derivatives	(5)	(4)	10
Commodity derivatives	18	30	40
Total	$ (22)	$ 12	$ (73)
Gains (losses) reclassified from AOCL to earnings			
Interest rate derivatives	$ (82)	$ (101)	$ (116)
Cross-currency derivatives	34	8	(24)
Foreign currency derivatives	(20)	(8)	32
Commodity derivatives	17	56	31
Total	$ (51)	$ (45)	$ (77)
Loss reclassified from AOCL to earnings due to discontinuance of hedge accounting [1]	$ (13)	$ —	$ —
Gain (losses) recognized in earnings related to			
Ineffective portion of cash flow hedges	$ 3	$ (1)	$ (6)
Not designated as hedging instruments:			
Foreign currency derivatives	$ 1	$ 19	$ 211
Commodity derivatives and other	14	(16)	(29)
Total	$ 15	$ 3	$ 182

(1) Cash flow hedge was discontinued because it was probable the forecasted transaction will not occur.

The AOCL expected to decrease pre-tax income from continuing operations, primarily due to interest rate derivatives, for the twelve months ended December 31, 2017 is $58 million.

6. FINANCING RECEIVABLES

Receivables with contractual maturities of greater than one year are considered financing receivables, primarily related to amended agreements or government resolutions due from CAMMESA. The following table presents financing receivables by country as of the dates indicated (in millions):

December 31,	2017	2016
Argentina	$ 177	$ 236
Other	17	20
Total	$ 194	$ 256

Argentina

Collection of the principal and interest on these receivables is subject to various business risks and uncertainties, including, but not limited to, the continued operation of power plants which generate cash for payments of these receivables, regulatory changes that could impact the timing and amount of collections, and economic conditions in Argentina. The Company monitors these risks, including the credit ratings of the Argentine government, on a quarterly basis to assess the collectability of these receivables. The Company accrues interest on these receivables if collectability is reasonably assured. The Company's collection estimates are based on assumptions it believes to be reasonable, but are inherently uncertain. Actual future cash flows could differ from these estimates. The decrease in Argentina financing receivables was primarily due to planned collections and unfavorable FX impacts.

FONINVEMEM Agreements — As a result of energy market reforms in 2004 and 2010, AES Argentina entered into three agreements with the Argentine government, referred to as the FONINVEMEM Agreements, to contribute a portion of their accounts receivable into a fund for financing the construction of combined cycle and gas-fired plants. These receivables accrue interest and are collected in monthly installments over 10 years once the related plant begins operations. In addition, AES Argentina receives an ownership interest in these newly built plants once the receivables have been fully repaid.

The FONINVEMEM receivables are denominated in Argentine pesos, but indexed to U.S. dollars, which represents a foreign currency derivative. As of December 31, 2017 and 2016, the amount of the foreign currency-related derivative assets associated with the FONINVEMEM financing receivables that were excluded from the table above had a fair value of $240 million and $255 million, respectively.

The receivables under the FONINVEMEM Agreements have been actively collected since the related plants commenced operations in 2010 and 2016. In assessing the collectability of the receivables under these agreements, the Company also considers historic collection evidence in accordance with the agreements.

Other Agreements — Other agreements primarily consist of resolutions passed by the Argentine government in which AES Argentina will receive compensation for investments in new generation plants and technologies. The timing of collections depend on corresponding agreements and collectability of these receivables are assessed on an ongoing basis.

7. 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,		2017	2016	2017	2016
Affiliate	Country	Carrying Value (in millions)		Ownership Interest %	
sPower	United States	$ 508	$ —	50%	—%
Guacolda [1]	Chile	357	362	33%	33%
OPGC [2]	India	269	195	49%	49%
Elsta [3]	Netherlands	38	41	50%	50%
Equity method investments of Distributed Energy [3]	United States	15	22	95%	95%
Barry [3]	United Kingdom	—	—	100%	100%
Other affiliates	Various	10	1		
Total		$ 1,197	$ 621		

(1) The Company's ownership in Guacolda is held through AES Gener, a 67%-owned consolidated subsidiary. AES Gener owns 50% of Guacolda, resulting in an AES effective ownership in Guacolda of 33%.
(2) OPGC has one coal-fired project under development which is an expansion of our existing OPGC business. The project started construction in April 2014 and is expected to begin operations in 2019.
(3) Represent VIEs in which the Company holds a variable interest, but is not the primary beneficiary.

sPower — In February 2017, the Company and Alberta Investment Management Corporation ("AIMCo") entered into an agreement to acquire FTP Power LLC ("sPower"). In July 2017, AES closed on the acquisition of its 48% ownership interest in sPower for $461 million. In November 2017, AES acquired an additional 2% ownership interest in sPower for $19 million. As the Company does not control sPower, it is accounted for as an equity method investment. The sPower portfolio includes solar and wind projects in operation, under construction, and in development located in the United States. The sPower equity method investment is reported in the US SBU reportable segment.

Guacolda — In September 2015, AES Gener and Global Infrastructure Partners ("GIP") executed a restructuring of Guacolda that increased Guacolda's tax basis in certain long-term assets and AES Gener's equity investment. As a result, AES Gener recorded $66 million in net equity in earnings of affiliates for the year ended December 31, 2015, of which $46 million is attributable to The AES Corporation.

AES Barry Ltd. — The Company holds a 100% ownership interest in AES Barry Ltd. ("Barry"), a dormant entity in the U.K. that disposed of its generation and other operating assets. Due to a debt agreement, no material financial or operating decisions can be made without the banks' consent, and the Company does not control Barry. As of December 31, 2017 and 2016, other long-term liabilities included $45 million and $41 million related to this debt agreement.

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		
Years ended December 31,	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Revenue	$ 762	$ 586	$ 641	$ 16	$ 23	$ 24
Operating margin	165	145	152	5	9	11
Net income (loss)	72	64	210	(15)	(2)	6
December 31,	**2017**	**2016**		**2017**	**2016**	
Current assets	$ 418	$ 308		$ 70	$ 16	
Noncurrent assets	5,372	2,577		102	181	
Current liabilities	633	626		10	10	
Noncurrent liabilities	2,629	1,209		147	122	
Stockholders' equity	2,527	1,048		15	65	

At December 31, 2017, retained earnings included $254 million related to the undistributed earnings of the Company's 50%-or-less owned affiliates. Distributions received from these affiliates were $69 million, $24 million, and $18 million for the years ended December 31, 2017, 2016, and 2015, respectively. As of December 31, 2017, the aggregate carrying amount of our investments in equity affiliates exceeded the underlying equity in their net assets by $46 million.

8. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill — The following table summarizes the carrying amount of goodwill by reportable segment for the years ended December 31, 2017 and 2016 (in millions):

	US	Andes	MCAC	Eurasia	Total
Balance as of December 31, 2016					
Goodwill	$ 2,674	$ 899	$ 149	$ 190	$ 3,912
Accumulated impairment losses	(2,633)	—	—	(122)	(2,755)
Net balance	41	899	149	68	1,157
Transfer to assets held-for-sale [1]	—	(30)	—	(68)	(98)
Balance as of December 31, 2017					
Goodwill	2,674	869	149	122	3,814
Accumulated impairment losses	(2,633)	—	—	(122)	(2,755)
Net balance	$ 41	$ 869	$ 149	$ —	$ 1,059

(1) See Note 22---*Held-For-Sale Businesses and Dispositions* for further information.

DP&L — During the fourth quarter of 2015, the Company performed the annual goodwill impairment test at its DP&L reporting unit and recognized a goodwill impairment expense of $317 million. The reporting unit failed Step 1 as its fair value was less than its carrying amount, which was primarily due to a decrease in forecasted dark spreads that were driven by decreases in projected forward power prices, and lower than expected revenues from a new CP product. The fair value of the reporting unit was determined under the income approach using a discounted cash flow valuation model. The significant assumptions included within the discounted cash flow valuation model were forward commodity price curves, the amount of non-bypassable charges from the pending ESP, expected revenues from the new CP product, and planned environmental expenditures. In Step 2, goodwill was determined to have an implied negative fair value after the hypothetical purchase price allocation under the accounting guidance for business combinations; therefore, a full impairment of the remaining goodwill balance of $317 million was recognized. DP&L is reported in the US SBU reportable segment.

Other Intangible Assets — The following table summarizes the balances comprising *Other intangible assets* in the accompanying Consolidated Balance Sheets (in millions) as of the periods indicated:

	December 31, 2017			December 31, 2016		
	Gross Balance	Accumulated Amortization	Net Balance	Gross Balance	Accumulated Amortization	Net Balance
Subject to Amortization						
Internal-use software	$ 416	$ (330)	$ 86	$ 396	$ (304)	$ 92
Contracts	92	(21)	71	53	(15)	38
Contractual payment rights [(1)]	65	(47)	18	56	(42)	14
Project development rights	57	(1)	56	4	(1)	3
Other [(2)]	98	(42)	56	103	(37)	66
Subtotal	728	(441)	287	612	(399)	213
Indefinite-Lived Intangible Assets						
Land use rights	45	—	45	47	—	47
Water rights	20	—	20	17	—	17
Other	14	—	14	10	—	10
Subtotal	79	—	79	74	—	74
Total	$ 807	$ (441)	$ 366	$ 686	$ (399)	$ 287

(1) Represent legal rights to receive system reliability payments from the regulator.
(2) Includes management rights, sales concessions, gas extraction rights, and other individually insignificant intangible assets.

The following tables summarize other intangible assets acquired during the periods indicated (in millions):

December 31, 2017	Amount	Subject to Amortization/ Indefinite-Lived	Weighted Average Amortization Period (in years)	Amortization Method
Project Development Rights	$ 53	Subject to Amortization	30	Straight-line
Contracts	34	Subject to Amortization	25	Straight-line
Internal-use software	17	Subject to Amortization	7	Straight-line
Other	8	Various	N/A	N/A
Total	$ 112			

December 31, 2016	Amount	Subject to Amortization/ Indefinite-Lived	Weighted Average Amortization Period (in years)	Amortization Method
Internal-use software	$ 41	Subject to Amortization	4	Straight-line
Contracts	24	Subject to Amortization	26	Straight-line
Other	5	Subject to Amortization	13	Straight-line
Total	$ 70			

The following table summarizes the estimated amortization expense by intangible asset category for 2018 through 2022:

(in millions)	2018	2019	2020	2021	2022
Internal-use software	$ 17	$ 14	$ 12	$ 10	$ 9
Contracts	5	5	5	5	5
Other	11	12	10	8	9
Total	$ 33	$ 31	$ 27	$ 23	$ 23

Intangible asset amortization expense was $34 million, $37 million and $47 million for the years ended December 31, 2017, 2016 and 2015, respectively.

9. 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,	2017	2016	Recovery/Refund Period
REGULATORY ASSETS			
Current regulatory assets:			
El Salvador tariff recoveries	$ 59	$ 54	Quarterly as part of the tariff adjustment
Other	60	34	Various
Total current regulatory assets	119	88	
Noncurrent regulatory assets:			
IPL and DPL defined benefit pension obligations [1]	298	316	Various
IPL and DPL income taxes recoverable from customers [1]	—	87	Various
IPL deferred Midwest ISO costs	102	114	9 years
IPL environmental costs	48	41	Various
Other	94	97	Various
Total noncurrent regulatory assets	542	655	
TOTAL REGULATORY ASSETS	$ 661	$ 743	
REGULATORY LIABILITIES			
Current regulatory liabilities:			
DPL efficiency program costs	$ 10	$ 14	Annually as part of the tariff adjustment
Other	7	27	Various
Total current regulatory liabilities	17	41	
Noncurrent regulatory liabilities:			
IPL and DPL asset retirement obligations	830	795	Over life of assets
IPL and DPL deferred income taxes	243	2	Various
Other	6	5	Various
Total noncurrent regulatory liabilities	1,079	802	
TOTAL REGULATORY LIABILITIES	$ 1,096	$ 843	

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

Our regulatory assets primarily consist of costs that are generally non-controllable, such as purchased electricity, energy transmission, the difference between actual fuel costs and the fuel costs recovered in the tariffs, and other sector costs. These costs are recoverable or refundable as defined by the laws and regulations in our various markets. Our regulatory assets also include defined pension and postretirement benefit obligations equal to the previously unrecognized actuarial gains and losses and prior services costs that are expected to be recovered through future rates. Other current and noncurrent regulatory assets primarily consist of:

- Demand charges at DPL;
- Unamortized premiums reacquired or redeemed on long term debt at IPL and DPL, which are amortized over the lives of the original issuances; and
- Unrecovered fuel and purchased power costs at IPL and DPL.

Our regulatory liabilities primarily consist of obligations for removal costs which do not have an associated legal retirement obligation. Our regulatory liabilities also include deferred income taxes associated with the reduction of the U.S. federal income tax rate which will be passed through to our regulated customers via a decrease in future retail rates, see Note 20—*Income Taxes* for further information.

In the accompanying Consolidated Balance Sheets the current regulatory assets and liabilities are reflected in *Other current assets* and *Accrued and other liabilities*, respectively, and the noncurrent regulatory assets and liabilities are reflected in *Other noncurrent assets* and *Other noncurrent liabilities*, respectively. The following table summarizes regulatory assets and liabilities by reportable segment in millions as of the periods indicated:

	December 31, 2017		December 31, 2016	
	Regulatory Assets	Regulatory Liabilities	Regulatory Assets	Regulatory Liabilities
US SBU	$ 602	$ 1,095	$ 689	$ 842
MCAC SBU	59	—	54	—
Brazil SBU	—	1	—	1
Total	$ 661	$ 1,096	$ 743	$ 843

10. DEBT

NON-RECOURSE DEBT — The following table summarizes the carrying amount and terms of non-recourse debt at our subsidiaries as of the periods indicated (in millions):

NON-RECOURSE DEBT	Weighted Average Interest Rate	Maturity	December 31, 2017	2016
Variable Rate: [1]				
Bank loans	4.52%	2018 – 2050	$ 2,488	$ 2,601
Notes and bonds	8.06%	2020 – 2026	900	471
Debt to (or guaranteed by) multilateral, export credit agencies or development banks [2]	3.28%	2023 – 2034	3,668	3,189
Fixed Rate:				
Bank loans	4.54%	2018 – 2040	993	767
Notes and bonds	5.68%	2019 – 2073	7,388	7,822
Debt to (or guaranteed by) multilateral, export credit agencies or development banks [2]	5.35%	2023 – 2034	271	328
Other	5.81%	2018 – 2061	26	30
Unamortized (discount) premium & debt issuance (costs), net			(394)	(425)
Subtotal			$ 15,340	$ 14,783
Less: Current maturities			(2,164)	(1,052)
Noncurrent maturities			$ 13,176	$ 13,731

(1) 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 of a fixed component. The Company has interest rate swaps and option agreements in an aggregate notional principal amount of approximately $3.6 billion on non-recourse debt outstanding at December 31, 2017. These agreements economically fix the variable component of the interest rates on the portion of the variable-rate debt being hedged so that the total interest rate on that debt has been fixed at rates ranging from approximately 2.49% to 8.00%. The debt agreements expire at various dates from 2018 through 2073.

(2) Multilateral loans include loans funded and guaranteed by bilaterals, multilaterals, development banks and other similar institutions.

Non-recourse debt as of December 31, 2017 is scheduled to reach maturity as shown below (in millions):

December 31,	Annual Maturities
2018	$ 2,245
2019	796
2020	1,396
2021	1,833
2022	1,768
Thereafter	7,696
Unamortized (discount) premium & debt issuance (costs), net	(394)
Total	$ 15,340

As of December 31, 2017, AES subsidiaries with facilities under construction had a total of approximately $1.8 billion of committed but unused credit facilities available to fund construction and other related costs. Excluding these facilities under construction, AES subsidiaries had approximately $1.7 billion in a number of available but 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, 2017, the Company's subsidiaries had the following significant debt transactions:

Subsidiary	Issuances	Repayments	Gain (Loss) on Extinguishment of Debt
IPALCO	$ 608	$ (528)	$ (9)
Tietê	585	(293)	(5)
Southland	557	—	—
Gener	335	(426)	(20)
AES Argentina	310	(181)	65
Los Mina	303	(275)	(4)
Colon	262	—	—
Masinloc	160	(51)	—
DPL	103	(249)	(3)
Other	285	(547)	(1)
Total	$ 3,508	$ (2,550)	$ 23

Southland — In June 2017, AES Southland Energy LLC closed on $2 billion of aggregate principal long-term non-recourse debt financing to fund the Southland re-powering construction projects (“the Southland financing”). The Southland financing consists of $1.5 billion senior secured notes, amortizing through 2040, and $492 million senior secured term loan, amortizing through 2027. The long-term debt financing has a combined weighted average cost of approximately 4.5%. As of December 31, 2017, $557 million of the senior secured notes were outstanding under the Southland financing.

AES Argentina — In February 2017, AES Argentina issued $300 million aggregate principal of unsecured and unsubordinated notes due in 2024. The net proceeds from this issuance were used for the prepayment of $75 million of non-recourse debt related to the construction of the San Nicolas Plant resulting in a gain on extinguishment of debt of approximately $65 million.

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, 2017 and 2016, approximately $642 million and $535 million, respectively, of restricted cash was maintained in accordance with certain covenants of the non-recourse debt agreements, and these amounts were included within *Restricted cash* and *Debt service reserves and other deposits* in the accompanying Consolidated Balance Sheets.

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 $2.8 billion at December 31, 2017.

The following table summarizes the Company's subsidiary non-recourse debt in default (in millions) as of December 31, 2017. Due to the defaults, these amounts are included in the current portion of non-recourse debt:

Subsidiary	Primary Nature of Default	December 31, 2017	
		Default	Net Assets
Alto Maipo (Chile)	Covenant	$ 618	$ 352
AES Puerto Rico	Covenant/Payment	365	692
AES Ilumina	Covenant	36	54
Total		$ 1,019	

The amounts in default related to Puerto Rico are covenant and payment defaults. In November 2017, AES Puerto Rico signed Forbearance and Standstill Agreements with their lenders to prevent the lenders from taking action against the Company due to these default events. These agreements will expire on March 22, 2018.

All other defaults listed are not payment defaults. All of the subsidiary non-recourse defaults were triggered by failure to comply with covenants and/or conditions such as (but not limited to) failure to meet information covenants, complete construction or other milestones in an allocated time, meet certain minimum or maximum financial ratios, or other requirements contained in the non-recourse debt documents of the applicable subsidiary.

The AES Corporation's recourse debt agreements include cross-default clauses that will trigger if a subsidiary or group of subsidiaries for which the non-recourse debt is in default provides 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, 2017, the Company has no defaults which result in or are at risk of triggering 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 senior secured revolving credit facility, restricted payments will be limited to regular quarterly shareholder dividends at the then-prevailing rate. Payment defaults and bankruptcy defaults would preclude the making of any restricted payments.

RECOURSE DEBT — The following table summarizes the carrying amount and terms of recourse debt of the Company as of the periods indicated (in millions):

	Interest Rate	Final Maturity	December 31, 2017	December 31, 2016
Senior Unsecured Note	LIBOR + 3.00%	2019	$ —	$ 240
Senior Unsecured Note	8.00%	2020	228	469
Senior Unsecured Note	7.38%	2021	690	966
Drawings on secured credit facility	LIBOR + 2.00%	2021	207	—
Senior Secured Term Loan	LIBOR + 2.00%	2022	521	—
Senior Unsecured Note	4.88%	2023	713	713
Senior Unsecured Note	5.50%	2024	738	738
Senior Unsecured Note	5.50%	2025	573	573
Senior Unsecured Note	6.00%	2026	500	500
Senior Unsecured Note	5.13%	2027	500	—
Term Convertible Trust Securities	6.75%	2029	—	517
Unamortized (discount) premium & debt issuance (costs), net			(40)	(45)
Subtotal			$ 4,630	$ 4,671
Less: Current maturities			(5)	—
Noncurrent maturities			$ 4,625	$ 4,671

The following table summarizes the principal amounts due under our recourse debt for the next five years and thereafter (in millions):

December 31,	Net Principal Amounts Due
2018	$ 5
2019	5
2020	234
2021	902
2022	500
Thereafter	3,024
Unamortized (discount) premium & debt issuance (costs), net	(40)
Total recourse debt	$ 4,630

In August 2017, the Company issued $500 million aggregate principal amount of 5.125% senior notes due in 2027. The Company used these proceeds to redeem at par $240 million aggregate principal of its existing LIBOR + 3.00% senior unsecured notes due in 2019 and repurchased $217 million of its existing 8.00% senior unsecured notes due in 2020. As a result of the latter transactions, the Company recognized a loss on extinguishment of debt of $36 million.

In May 2017, the Company closed on $525 million aggregate principal LIBOR + 2.00% secured term loan due in 2022. In June 2017, the Company used these proceeds to redeem at par all $517 million aggregate principal of its existing Term Convertible Securities. As a result of the latter transaction, the Company recognized a loss on extinguishment of debt of $6 million.

In March 2017, the Company redeemed via tender offers $276 million aggregate principal of its existing 7.375% senior unsecured notes due in 2021 and $24 million of its existing 8.00% senior unsecured notes due in 2020. As a result of these transactions, the Company recognized a loss on extinguishment of debt of $47 million.

In July 2016, the Company redeemed in full the $181 million balance of its 8.00% outstanding senior unsecured notes due 2017 using proceeds from its senior secured credit facility. As a result, the Company recognized a loss on extinguishment of debt of $16 million.

In May 2016, the Company issued $500 million aggregate principal amount of 6.00% senior notes due 2026. The Company used these proceeds to redeem, at par, $495 million aggregate principal of its existing LIBOR + 3.00% senior unsecured notes due 2019. As a result of the latter transaction, the Company recognized a loss on extinguishment of debt of $4 million.

In January 2016, the Company redeemed $125 million of its senior unsecured notes outstanding. The repayment included a portion of the 7.375% senior notes due in 2021, the 4.875% senior notes due in 2023, the 5.5% senior notes due in 2024, the 5.5% senior notes due in 2025 and the floating rate senior notes due in 2019. As a result of these transactions, the Company recognized a net gain on extinguishment of debt of $7 million.

Recourse Debt Covenants and Guarantees — The Company's obligations under the senior secured credit facility and senior secured term loan are, subject to certain exceptions, secured by (i) all of the capital stock of domestic subsidiaries owned directly by the Company and 65% of the capital stock of certain foreign subsidiaries owned directly or indirectly by the Company; and (ii) certain intercompany receivables, certain intercompany notes and certain intercompany tax sharing agreements.

The senior secured credit facility and senior secured term loan is subject to mandatory prepayment under certain circumstances, including the sale of certain assets. In such a situation, the net cash proceeds from the sale must be applied pro rata to repay the term loan, if any, using 60% of net cash proceeds, reduced to 50% when and if the parent's recourse debt to cash flow ratio is less than 5:1. The lenders have the option to waive their pro rata redemption.

The senior secured credit facility contains customary covenants and restrictions on the Company's ability to engage in certain activities, including, but not limited to, limitations on other indebtedness, liens, investments and guarantees; limitations on restricted payments such as shareholder dividends and equity repurchases; restrictions on mergers and acquisitions, sales of assets, leases, transactions with affiliates and off-balance sheet or derivative arrangements; and other financial reporting requirements.

The senior secured credit facility also contains financial covenants, evaluated quarterly, requiring the Company to maintain a minimum ratio of adjusted operating cash flow to interest charges on recourse debt of 1.3 times and a maximum ratio of recourse debt to adjusted operating cash flow of 7.5 times.

The terms of the Company's senior unsecured notes and senior secured term loan contain certain covenants including, without limitation, limitation on the Company's ability to incur liens or enter into sale and leaseback transactions.

TERM CONVERTIBLE TRUST SECURITIES — In 1999, AES Trust III, a wholly-owned special purpose business trust and a VIE, issued approximately 10.35 million of $50 par value TECONS with a quarterly coupon payment of $0.844 for total proceeds of $517 million and concurrently purchased $517 million of 6.75% Junior Subordinated Convertible Debentures due 2029 (the "6.75% Debentures") issued by AES. AES, at its option, may redeem the 6.75% Debentures which would result in the required redemption of the TECONS issued by AES Trust III for $50 per TECON. As of December 31, 2016, the sole assets of AES Trust III were the 6.75% Debentures. In June 2017, the Company redeemed the 6.75% Debentures and redeemed at par all remaining aggregate principal of its existing TECONs.

11. COMMITMENTS

LEASES — The Company enters into long-term non-cancelable lease arrangements which, for accounting purposes, are classified as either operating or capital leases. Operating leases primarily include certain transmission lines, office rental and site leases. Operating lease rental expense for the years ended December 31, 2017, 2016, and 2015 was $61 million, $61 million and $45 million, respectively. Capital leases primarily include transmission lines, vehicles, offices, and other operating equipment. Capital leases are recognized in Property, Plant and Equipment within *Electric generation, distribution assets and other*. The gross value of the capital lease assets as of December 31, 2017 and 2016 was $27 million and $22 million, respectively. The following table shows the future minimum lease payments under operating and capital leases for continuing operations together with the present value of the net minimum lease payments under capital leases as of December 31, 2017 for 2018 through 2022 and thereafter (in millions):

	Future Commitments for	
December 31,	**Capital Leases**	**Operating Leases**
2018	$ 2	$ 58
2019	1	58
2020	1	58
2021	1	59
2022	1	58
Thereafter	12	644
Total	$ 18	$ 935
Less: Imputed interest	(10)	
Present value of total minimum lease payments	$ 8	

CONTRACTS — The Company enters into long-term contracts for construction projects, maintenance and service, transmission of electricity, operations services and purchase 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, 2017 for 2018 through 2022 and thereafter as well as actual purchases under these contracts for the years ended December 31, 2017, 2016, and 2015 (in millions):

Actual purchases during the year ended December 31,	Electricity Purchase Contracts	Fuel Purchase Contracts	Other Purchase Contracts
2015	$ 545	$ 1,262	$ 1,833
2016	420	1,790	817
2017	747	1,619	1,945
Future commitments for the year ending December 31,			
2018	$ 581	$ 1,759	$ 1,488
2019	508	1,051	931
2020	440	591	470
2021	469	538	234
2022	438	454	547
Thereafter	2,065	1,466	1,314
Total	$ 4,501	$ 5,859	$ 4,984

12. CONTINGENCIES

Guarantees and Letters of Credit — In connection with certain project financings, acquisitions and dispositions, power purchases and other agreements, the Parent Company has expressly undertaken limited obligations and commitments, most of which will only be effective or will be terminated upon the occurrence of future events. In the normal course of business, the Parent Company has entered into various agreements, mainly guarantees and letters of credit, to provide financial or performance assurance to third parties on behalf of AES businesses. These agreements are entered into primarily to support or enhance the creditworthiness otherwise achieved by a business on a stand-alone basis, thereby facilitating the availability of sufficient credit to accomplish their intended business purposes. Most of the contingent obligations relate to future performance commitments which the Company expects to fulfill within the normal course of business. The expiration dates of these guarantees vary from less than one year to more than 17 years.

The following table summarizes the Parent Company's contingent contractual obligations as of December 31, 2017. Amounts presented in the following table represent the Parent Company's current undiscounted exposure to guarantees and the range of maximum undiscounted potential exposure. The maximum exposure is not reduced by the amounts, if any, that could be recovered under the recourse or collateralization provisions in the guarantees. There were no obligations made by the Parent Company for the direct benefit of the lenders associated with the non-recourse debt of its businesses.

Contingent Contractual Obligations	Amount (in millions)	Number of Agreements	Maximum Exposure Range for Each Agreement (in millions)
Guarantees and commitments	$ 815	21	$1 — 272
Letters of credit under the unsecured credit facility	52	4	$2 — 26
Asset sale related indemnities (1)	27	1	27
Letters of credit under the senior secured credit facility	36	21	<$1 — 13
Total	$ 930	47	

(1) Excludes 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.

During the year ended December 31, 2017, the Company paid letter of credit fees ranging from 0.25% to 2.25% per annum on the outstanding amounts of letters of credit.

Environmental — The Company periodically reviews its obligations as they relate to compliance with environmental laws, including site restoration and remediation. As of December 31, 2017 and 2016 the Company had recognized liabilities of $5 million and $9 million, respectively, for projected environmental remediation costs. Due to the uncertainties associated with environmental assessment and remediation activities, future costs of compliance or remediation could be higher or lower than the amount currently accrued. Moreover, where no liability has been recognized, it is reasonably possible that the Company may be required to incur remediation costs or make expenditures in amounts that could be material but could not be estimated as of December 31, 2017. In aggregate, the Company estimates that the range of potential losses related to environmental matters, where estimable, to be up to $18 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 $50 million and $59 million as of December 31, 2017 and 2016, 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, 2017. The material contingencies where a loss is reasonably possible primarily include claims under financing agreements; disputes with offtakers, suppliers and EPC contractors; alleged violation of monopoly laws and regulations; income tax and non-income tax matters with tax authorities; and regulatory matters. In aggregate, the Company estimates that the range of potential losses, where estimable, related to these reasonably possible material contingencies to be between $140 million and $173 million. The amounts considered reasonably possible do not include amounts accrued, as discussed above. These material contingencies do not include income tax-related contingencies which are considered part of our uncertain tax positions.

13. BENEFIT PLANS

Defined Contribution Plan — The Company sponsors four defined contribution plans ("the DC Plans"). Two plans cover U.S. non-union employees; one for Parent Company and certain US SBU business employees, and one for DPL employees. The remaining two plans include union and non-union employees at IPL and union employees at DPL. 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, 2017, 2016 and 2015, costs for defined contribution plans were approximately $23 million, $15 million and $18 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 31 active DB Plans as of December 31, 2017, 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):

	2017		2016	
	U.S.	Foreign	U.S.	Foreign
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Benefit obligation as of January 1	$ 1,188	$ 411	$ 1,172	$ 374
Service cost	13	10	13	9
Interest cost	41	22	42	21
Employee contributions	—	1	—	1
Plan amendments	1	(1)	—	(4)
Plan curtailments	3	—	2	—
Plan settlements	—	(2)	—	—
Benefits paid	(71)	(22)	(60)	(19)
Actuarial loss	82	29	19	58
Effect of foreign currency exchange rate changes	—	22	—	(29)
Benefit obligation as of December 31	$ 1,257	$ 470	$ 1,188	$ 411
CHANGE IN PLAN ASSETS:				
Fair value of plan assets as of January 1	$ 1,044	$ 402	$ 1,021	$ 379
Actual return on plan assets	141	31	61	59
Employer contributions	13	18	22	18
Employee contributions	—	1	—	1
Plan settlements	—	(2)	—	—
Benefits paid	(71)	(22)	(60)	(19)
Effect of foreign currency exchange rate changes	—	27	—	(36)
Fair value of plan assets as of December 31	$ 1,127	$ 455	$ 1,044	$ 402
RECONCILIATION OF FUNDED STATUS				
Funded status as of December 31	$ (130)	$ (15)	$ (144)	$ (9)

The following table summarizes the amounts recognized on the Consolidated Balance Sheets related to the funded status of the DB Plans, both domestic and foreign, as of the periods indicated (in millions):

December 31,	2017		2016	
Amounts Recognized on the Consolidated Balance Sheets	U.S.	Foreign	U.S.	Foreign
Noncurrent assets	$ —	$ 69	$ —	$ 60
Accrued benefit liability—current	—	(6)	—	(5)
Accrued benefit liability—noncurrent	(130)	(78)	(144)	(64)
Net amount recognized at end of year	$ (130)	$ (15)	$ (144)	$ (9)

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

December 31,	2017		2016	
	U.S.	Foreign	U.S.	Foreign
Accumulated Benefit Obligation	$ 1,236	$ 433	$ 1,167	$ 384
Information for pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	$ 1,257	$ 109	$ 1,188	$ 90
Accumulated benefit obligation	1,236	97	1,167	80
Fair value of plan assets	1,127	33	1,044	25
Information for pension plans with a projected benefit obligation in excess of plan assets:				
Projected benefit obligation	$ 1,257	$ 238	$ 1,188	$ 212
Fair value of plan assets	1,127	154	1,044	142

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,		2017		2016	
		U.S.	Foreign	U.S.	Foreign
Benefit Obligation:	Discount rate	3.67%	5.23%	4.28%	5.83%
	Rate of compensation increase	3.34%	4.65%	3.34%	4.86%
Periodic Benefit Cost:	Discount rate	4.28%	5.83% [(1)]	4.44%	6.10% [(1)]
	Expected long-term rate of return on plan assets	6.67%	5.30%	6.67%	5.09%
	Rate of compensation increase	3.34%	4.86%	3.34%	4.45%

(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 2017. 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, 2017 is affected by the assumptions as of that date. Pension expense for 2017 is affected by the December 31, 2016 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	$ (13)
Decrease of 1% in the discount rate	12
Increase of 1% in the long-term rate of return on plan assets	(15)
Decrease of 1% in the long-term rate of return on plan assets	15

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

December 31,	2017		2016		2015	
Components of Net Periodic Benefit Cost:	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign
Service cost	$ 13	$ 10	$ 13	$ 9	$ 16	$ 10
Interest cost	41	23	42	21	48	23
Expected return on plan assets	(69)	(21)	(68)	(19)	(70)	(20)
Amortization of prior service cost	6	—	7	(1)	7	—
Amortization of net loss	18	2	18	2	20	2
Curtailment loss recognized	4	—	4	—	—	—
Total pension cost	$ 13	$ 14	$ 16	$ 12	$ 21	$ 15

The following table summarizes in millions the amounts reflected in AOCL, including AOCL attributable to noncontrolling interests, on the Consolidated Balance Sheet as of December 31, 2017, that have not yet been recognized as components of net periodic benefit cost and amounts expected to be reclassified to earnings in the next fiscal year (in millions):

December 31, 2017	Accumulated Other Comprehensive Income (Loss)		Amounts expected to be reclassified to earnings in next fiscal year	
	U.S.	Foreign	U.S.	Foreign
Prior service cost	$ (1)	$ 1	$ —	$ —
Unrecognized net actuarial loss	(22)	(81)	(2)	(3)
Total	$ (23)	$ (80)	$ (2)	$ (3)

The following table summarizes the Company's target allocation for 2017 and pension plan asset allocation, both domestic and foreign, as of the periods indicated:

			Percentage of Plan Assets as of December 31,			
	Target Allocations		2017		2016	
Asset Category	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign
Equity securities	33%	4%	31.90%	4.61%	50.96%	18.66%
Debt securities	65%	93%	64.53%	93.10%	45.88%	78.35%
Real estate	2%	—%	3.20%	0.44%	3.16%	0.75%
Other	—%	3%	0.37%	1.85%	—%	2.24%
Total pension assets			100.00%	100.00%	100.00%	100.00%

The U.S. DB Plans seek to achieve the following long-term investment objectives:

- maintenance of sufficient income and liquidity to pay retirement benefits and other lump sum payments;
- long-term rate of return in excess of the annualized inflation rate;
- long-term rate of return, net of relevant fees, that meets or exceeds the assumed actuarial rate; and
- long-term competitive rate of return on investments, net of expenses, that equals or exceeds various benchmark rates.

The asset allocation is reviewed periodically to determine a suitable asset allocation which seeks to manage risk through portfolio diversification and takes into account the above-stated objectives, in conjunction with current funding levels, cash flow conditions and economic and industry trends. The following table summarizes the Company's U.S. DB Plan assets by category of investment and level within the fair value hierarchy as of the periods indicated (in millions):

		December 31, 2017				December 31, 2016			
U.S. Plans		Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Equity securities:	Mutual funds	$ 359	$ —	$ —	$ 359	$ 532	$ —	$ —	$ 532
Debt securities:	Government debt securities	135	—	—	135	86	—	—	86
	Mutual funds [1]	593	—	—	593	393	—	—	393
Real estate:	Real estate	—	36	—	36	—	33	—	33
Other:	Cash and cash equivalents	4	—	—	4	—	—	—	—
	Total plan assets	$ 1,091	$ 36	$ —	$ 1,127	$ 1,011	$ 33	$ —	$ 1,044

[1] Mutual funds categorized as debt securities consist of mutual funds for which debt securities are the primary underlying investment.

The investment strategy of the foreign DB Plans seeks to maximize return on investment while minimizing risk. The assumed asset allocation has less exposure to equities in order to closely match market conditions and near term forecasts. The following table summarizes the Company's foreign DB plan assets by category of investment and level within the fair value hierarchy as of the periods indicated (in millions):

		December 31, 2017				December 31, 2016			
Foreign Plans		Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Equity securities:	Mutual funds	$ 20	$ —	$ —	$ 20	$ 71	$ —	$ —	$ 71
	Private equity	—	—	1	1	—	—	4	4
Debt securities:	Government debt securities	11	—	—	11	10	—	—	10
	Mutual funds [1]	323	90	—	413	215	90	—	305
Real estate:	Real estate	—	—	2	2	—	—	3	3
Other:	Participant loans [2]	—	—	—	—	—	—	2	2
	Other assets	1	—	7	8	4	—	3	7
	Total plan assets	$ 355	$ 90	$ 10	$ 455	$ 300	$ 90	$ 12	$ 402

[1] Mutual funds categorized as debt securities consist of mutual funds for which debt securities are the primary underlying investment.
[2] Loans to participants are stated at cost, which approximates fair value.

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 2018	$ 39	$ 15
Expected benefit payments for fiscal year ending:		
2018	71	23
2019	73	23
2020	74	25
2021	75	26
2022	76	27
2023 - 2027	380	170

14. EQUITY

Equity Transactions with Noncontrolling Interests

Alto Maipo — In March 2017, AES Gener completed the legal and financial restructuring of Alto Maipo. As part of this restructuring, AES indirectly acquired the 40% ownership interest of the noncontrolling shareholder, for a de minimis payment, and sold a 6.7% interest in the project to the construction contractor. This transaction resulted in a $196 million increase to the Parent Company's Stockholders' Equity due to an increase in additional paid-in-capital of $229 million, offset by the reclassification of accumulated other comprehensive losses from NCI to the Parent Company Stockholders' Equity of $33 million. No gain or loss was recognized in net income as the sale was not considered to be a sale of in-substance real estate. After completion of the sale, the Company has an effective 62% economic interest in Alto Maipo. As the Company maintained control of the partnership after the sale, Alto Maipo continues to be consolidated by the Company within the Andes SBU reportable segment.

Dominican Republic — As part of a purchase agreement executed in 2014, Estrella and Linda Groups, an investor-based group in the Dominican Republic, had options to acquire additional interests in our businesses in the Dominican Republic. In December 2015, Estrella and Linda Groups exercised their first call option to acquire an additional 2% of our businesses in the Dominican Republic for $18 million, resulting in a net increase of $7 million to additional paid-in-capital. No gain or loss was recognized in net income as the sale was not considered to be a sale of in-substance real estate. After exercising this option, Estrella and Linda Groups held a 10% interest in our businesses in the Dominican Republic. Estrella and Linda Groups had a final option to acquire an additional 10% of our businesses in the Dominican Republic for $125 million which expired in December 2017.

In September 2017, Linda Group acquired 5% of our Dominican Republic business for $60 million, pre-tax. This transaction resulted in a net increase of $25 million to the Company's additional paid-in-capital and noncontrolling interest, respectively. No gain or loss was recognized in net income as the sale was not considered a sale of in-substance real estate. As the Company maintained control after the sale, our businesses in the Dominican Republic continue to be consolidated by the Company within the MCAC SBU reportable segment.

Jordan — In February 2016, the Company completed the sale of 40% of its interest in a wholly-owned subsidiary in Jordan that owns a controlling interest in the Jordan IPP4 gas-fired plant for $21 million. The transaction was accounted for as a sale of in-substance real estate and a pre-tax gain of $4 million, net of transaction costs, was recognized in net income. The cash proceeds from the sale are reflected in *Proceeds from the sale of businesses, net of cash sold* on the Consolidated Statement of Cash Flows for the period ended December 31, 2016. After completion of the sale, the Company has a 36% economic interest in Jordan IPP4 and continues to manage and operate the plant, with 40% owned by Mitsui Ltd. and 24% owned by Nebras Power Q.S.C. As the Company maintained control after the sale, Jordan IPP4 continues to be consolidated by the Company within the Eurasia SBU reportable segment.

Brazil Reorganization — In 2015, the Company completed a restructuring of Tietê. This transaction resulted in no change of ownership or control. The $27 million impact of this equity transaction was recognized in additional paid-in-capital.

Gener — In November 2015, the Company sold a 4% stake in AES Gener S.A. ("Gener") through its 99.9% owned subsidiary Inversiones Cachagua S.p.A ("Cachagua") for $145 million, net of transaction costs. The sale was of previously issued common shares of Gener to certain institutional investors and is not a sale of in-substance real estate. While the sale decreased Parent ownership interest from 70.7% to 66.7%, the Parent continues to retain its controlling financial interest in the subsidiary. The difference of $24 million between the fair value of the consideration received, net of taxes and transaction costs, and the amount by which the NCI is adjusted was recognized in additional paid-in-capital. No pre-tax gain or loss was recognized in net income as a result of this transaction.

The following table summarizes the net income attributable to The AES Corporation and all transfers (to) from noncontrolling interests for the periods indicated (in millions):

	December 31,		
	2017	2016	2015
Net income (loss) attributable to The AES Corporation	$ (1,161)	$ (1,130)	$ 306
Transfers from noncontrolling interest:			
Net increase in The AES Corporation's paid-in capital for sale of subsidiary shares	13	84	323
Additional paid-in-capital, IPALCO shares, transferred to redeemable stock of subsidiaries [1]	—	(84)	(377)
Increase (decrease) in The AES Corporation's paid-in-capital for purchase of subsidiary shares	240	(2)	—
Net transfers (to) from noncontrolling interest	253	(2)	(54)
Change from net income (loss) attributable to The AES Corporation and transfers (to) from noncontrolling interests	$ (908)	$ (1,132)	$ 252

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

Deconsolidations

UK Wind — During 2016, the Company determined it no longer had control of its wind development projects in the United Kingdom ("UK Wind") as the Company no longer held seats on the board of directors. In accordance with accounting guidance, UK Wind was deconsolidated and a loss on deconsolidation of $20 million was recorded to *Gain (loss) on disposal and sale of businesses* in the Consolidated Statement of Operations to write off the Company's noncontrolling interest in the project. The UK Wind projects were reported in the Eurasia SBU reportable segment.

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

	Foreign currency translation adjustment, net	Unrealized derivative losses, net	Unfunded pension obligations, net	Total
Balance at December 31,2015	$ (3,256)	$ (353)	$ (274)	$ (3,883)
Other comprehensive income (loss) before reclassifications	117	2	(13)	106
Amount reclassified to earnings	992	28	1	1,021
Other comprehensive income (loss)	$ 1,109	$ 30	$ (12)	$ 1,127
Balance at December 31, 2016	$ (2,147)	$ (323)	$ (286)	$ (2,756)
Other comprehensive loss before reclassifications	$ 18	$ (14)	$ (19)	$ (15)
Amount reclassified to earnings	643	37	248	928
Other comprehensive income	$ 661	$ 23	$ 229	$ 913
Reclassification from NCI due to Alto Maipo Restructuring	—	(33)	—	(33)
Balance at December 31, 2017	$ (1,486)	$ (333)	$ (57)	$ (1,876)

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 Condensed Consolidated Statements of Operations:

Details About AOCL Components	Affected Line Item in the Consolidated Statements of Operations	December 31, 2017	2016	2015
Foreign currency translation adjustments, net				
	Gain (loss) on disposal and sale of businesses	$ (188)	$ —	$ —
	Net loss from disposal and impairments of discontinued operations	(455)	(992)	—
	Net income (loss) attributable to The AES Corporation	$ (643)	$ (992)	$ —
Unrealized derivative gains (losses), net				
	Non-regulated revenue	$ 25	$ 111	$ 43
	Non-regulated cost of sales	(12)	(57)	(14)
	Interest expense	(79)	(107)	(112)
	Gain (loss) on disposal and sale of businesses	—	—	(4)
	Foreign currency transaction gains	15	8	12
	Income from continuing operations before taxes and equity in earnings of affiliates	(51)	(45)	(75)
	Income tax expense	1	8	11
	Net equity in earnings of affiliates	—	—	(2)
	Income (loss) from continuing operations	(50)	(37)	(66)
	Less: (Income) from continuing operations attributable to noncontrolling interests	13	9	18
	Net income (loss) attributable to The AES Corporation	$ (37)	$ (28)	$ (48)
Amortization of defined benefit pension actuarial losses, net				
	Non-regulated cost of sales	1	—	2
	General and administrative expenses	(1)	(1)	(2)
	Other expense	—	(1)	—
	Income from continuing operations before taxes and equity in earnings of affiliates	—	(2)	—
	Income tax expense	—	3	9
	Income from continuing operations	—	1	9
	Net loss from disposal and impairments of discontinued operations	(266)	(11)	(25)
	Net income (loss)	(266)	(10)	(16)
	Less: (Income) from continuing operations attributable to noncontrolling interests	—	9	14
	Add: Loss from discontinued operations attributable to noncontrolling interests	18	—	—
	Net income (loss) attributable to The AES Corporation	$ (248)	$ (1)	$ (2)
Total reclassifications for the period, net of income tax and noncontrolling interests		$ (928)	$ (1,021)	$ (50)

Common Stock Dividends — The Parent Company paid dividends of $0.12 per outstanding share to its common stockholders during the first, second, third and fourth quarters of 2017 for dividends declared in December 2016, February, July, and October 2017, respectively.

On December 8, 2017, the Board of Directors declared a quarterly common stock dividend of $0.13 per share payable on February 15, 2018 to shareholders of record at the close of business on February 1, 2018.

Stock Repurchase Program — No shares were repurchased in 2017. The cumulative repurchases from the commencement of the Program in July 2010 through December 31, 2017 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, 2017, $246 million remained available for repurchase under the Program.

The common stock repurchased has been classified as treasury stock and accounted for using the cost method. A total of 155,924,785 and 156,878,891 shares were held as treasury stock at December 31, 2017 and 2016, 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 Program in July 2010.

15. SEGMENTS AND GEOGRAPHIC INFORMATION

The segment reporting structure uses the Company's organizational structure as its foundation to reflect how the Company manages the businesses internally and is organized by geographic regions which provides a socio-political-economic understanding of our business. During the third quarter of 2017, the Europe and Asia SBUs were merged in order to leverage scale and are now reported as part of the Eurasia SBU. The management reporting structure is organized by five SBUs led by our President and Chief Executive Officer: US, Andes, Brazil, MCAC and Eurasia SBUs. The Company determined that it has five operating and five reportable segments corresponding to its SBUs. All prior period results have been retrospectively revised to reflect the new segment reporting structure. In February 2018, we announced a reorganization as a part of our ongoing strategy to simplify our portfolio, optimize our cost structure, and reduce our carbon intensity. The Company is currently evaluating the impact this reorganization will have on our segment reporting structure.

Corporate and Other — Corporate overhead costs which are not directly associated with the operations of our five reportable segments are included in "Corporate and Other." Also included are certain intercompany charges such as self-insurance premiums which are fully eliminated in consolidation.

The Company uses Adjusted PTC as its primary segment performance measure. Adjusted PTC, a non-GAAP measure, is defined by the Company as pre-tax income from continuing operations attributable to The AES Corporation excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses related to derivative transactions; (b) unrealized foreign currency gains or losses; (c) gains, losses and associated benefits and costs due to dispositions and acquisitions of business interests, including early plant closures; (d) losses due to impairments; (e) gains, losses and costs due to the early retirement of debt; and (f) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts, relocations, and office consolidation. 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. The Company has concluded Adjusted PTC better reflects the underlying business performance of the Company and is the most relevant measure considered in the Company's internal evaluation of the financial performance of its segments. Additionally, 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.

Revenue and Adjusted PTC are presented before inter-segment eliminations, which includes the effect of intercompany transactions with other segments except for interest, charges for certain management fees, and the write-off of intercompany balances, as applicable. All intra-segment activity has been eliminated within the segment. Inter-segment activity has been eliminated within the total consolidated results.

The following tables present financial information by segment for the periods indicated (in millions):

	Total Revenue		
Year Ended December 31,	**2017**	**2016**	**2015**
US SBU	$ 3,229	$ 3,429	$ 3,593
Andes SBU	2,710	2,506	2,489
Brazil SBU	542	450	962
MCAC SBU	2,448	2,172	2,353
Eurasia SBU	1,590	1,670	1,875
Corporate and Other	35	77	31
Eliminations	(24)	(23)	(43)
Total Revenue	$ 10,530	$ 10,281	$ 11,260

Reconciliation from Income from Continuing Operations before Taxes and Equity in Earnings of Affiliates:	Total Adjusted PTC		
Year Ended December 31,	2017	2016	2015
Income from continuing operations before taxes and equity in earnings of affiliates	$ 771	$ 187	$ 989
Add: Net equity earnings in affiliates	71	36	105
Less: Income from continuing operations before taxes, attributable to noncontrolling interests	(521)	(354)	(513)
Pre-tax contribution	321	(131)	581
Unrealized derivative gains	(3)	(9)	(166)
Unrealized foreign currency (gains) losses	(59)	22	95
Disposition/acquisition (gains) losses	123	6	(42)
Impairment losses	542	933	504
Loss on extinguishment of debt	62	29	179
Restructuring costs [(1)]	31	—	—
Total Adjusted PTC	$ 1,017	$ 850	$ 1,151

(1) One-time restructuring charges consisting of severance costs related to workforce reductions.

	Total Adjusted PTC		
Year Ended December 31,	2017	2016	2015
US SBU	$ 361	$ 347	$ 360
Andes SBU	386	390	482
Brazil SBU	60	38	92
MCAC SBU	340	267	327
Eurasia SBU	290	283	331
Corporate and Other	(420)	(475)	(441)
Total Adjusted PTC	$ 1,017	$ 850	$ 1,151

	Total Assets			Depreciation and Amortization			Capital Expenditures		
Year Ended December 31,	2017	2016	2015	2017	2016	2015	2017	2016	2015
US SBU	$ 9,852	$ 9,333	$ 9,800	$ 437	$ 471	$ 443	$ 858	$ 809	$ 861
Andes SBU	8,840	8,971	8,594	250	218	175	443	538	949
Brazil SBU	2,034	1,516	1,179	51	33	39	34	31	47
MCAC SBU	5,532	5,162	4,820	172	165	155	482	480	201
Eurasia SBU	4,557	5,777	6,200	127	149	166	211	279	131
Assets of discontinued operations and held-for-sale businesses	2,034	4,936	5,411	123	128	146	315	303	252
Corporate and Other	263	429	541	9	12	20	13	18	17
Total	$ 33,112	$ 36,124	$ 36,545	$ 1,169	$ 1,176	$ 1,144	$ 2,356	$ 2,458	$ 2,458

	Interest Income			Interest Expense		
Year Ended December 31,	2017	2016	2015	2017	2016	2015
US SBU	$ —	$ —	$ —	$ 258	$ 236	$ 262
Andes SBU	50	57	77	205	178	154
Brazil SBU	45	38	31	92	69	58
MCAC SBU	18	11	30	168	163	179
Eurasia SBU	130	139	116	167	179	158
Corporate and Other	1	—	2	280	309	334
Total	$ 244	$ 245	$ 256	$ 1,170	$ 1,134	$ 1,145

	Investments in and Advances to Affiliates			Net Equity in Earnings of Affiliates		
Year Ended December 31,	2017	2016	2015	2017	2016	2015
US SBU	$ 527	$ 23	$ 1	$ 41	$ 9	$ —
Andes SBU	358	363	345	28	15	83
MCAC SBU	3	(1)	—	(4)	(2)	—
Eurasia SBU	307	236	248	9	13	18
Corporate and Other	2	—	16	(3)	1	4
Total	$ 1,197	$ 621	$ 610	$ 71	$ 36	$ 105

The following table presents information, by country, about the Company's consolidated operations for each of the three years ended December 31, 2017, 2016, and 2015, and as of December 31, 2017 and 2016 (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			Property, Plant & Equipment, net	
Year Ended December 31,	**2017**	**2016**	**2015**	**2017**	**2016**
United States	$ 3,240	$ 3,489	$ 3,597	$ 7,403	$ 7,397
Non-U.S.:					
Chile	1,944	1,707	1,523	5,066	4,995
Dominican Republic	826	614	632	935	914
El Salvador	686	601	736	340	327
Brazil	541	450	962	1,286	789
Philippines	449	401	406	—	866
Argentina	435	359	399	223	195
Bulgaria	367	334	382	1,290	1,174
Mexico	352	342	383	687	699
Panama	338	312	297	1,615	1,233
Colombia	332	437	557	332	451
United Kingdom	328	337	396	108	151
Vietnam [1]	278	340	233	2	1
Puerto Rico	247	301	302	565	583
Jordan	95	136	248	431	452
Kazakhstan	67	103	155	—	178
Other Non-U.S.	5	18	52	13	10
Total Non-U.S.	7,290	6,792	7,663	12,893	13,018
Total	$ 10,530	$ 10,281	$ 11,260	$ 20,296	$ 20,415

(1) The Mong Duong II power project is accounted for as a service concession arrangement. Costs of construction of the plant have been deferred in *Service concession assets* on the Consolidated Balance Sheets.

16. SHARE-BASED COMPENSATION

RESTRICTED STOCK

Restricted Stock Units — The Company issues restricted stock units ("RSUs") under its long-term compensation plan. The RSUs are generally granted based upon a percentage of the participant's base salary. The units have a three-year vesting schedule and vest in one-third increments over the three-year 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, 2017, 2016, and 2015, 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, 2017, 2016, and 2015 had grant date fair values per RSU of $11.93, $9.42 and $12.03, respectively.

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,	**2017**	**2016**	**2015**
RSU expense before income tax	$ 17	$ 14	$ 13
Tax benefit	(4)	(4)	(3)
RSU expense, net of tax	$ 13	$ 10	$ 10
Total value of RSUs converted [1]	$ 10	$ 7	$ 16
Total fair value of RSUs vested	$ 15	$ 13	$ 12

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

Cash was not used to settle RSUs or compensation cost capitalized as part of the cost of an asset for the years ended December 31, 2017, 2016, and 2015. As of December 31, 2017, total unrecognized compensation cost related to RSUs of $17 million is expected to be recognized over a weighted average period of approximately 1.8 years. There were no modifications to RSU awards during the year ended December 31, 2017.

A summary of the activity of RSUs for the year ended December 31, 2017 follows (RSUs in thousands):

	RSUs	Weighted Average Grant Date Fair Values	Weighted Average Remaining Vesting Term
Non-vested at December 31, 2016	3,037	$ 10.70	
Vested	(1,337)	11.37	
Forfeited and expired	(280)	10.94	
Granted	1,546	11.93	
Non-vested at December 31, 2017	2,966	$ 11.02	1.4
Vested and expected to vest at December 31, 2017	2,711	$ 11.01	

The Company initially recognizes compensation cost on the estimated number of instruments for which the requisite service is expected to be rendered. In 2017, AES has estimated a weighted average forfeiture rate of 10.35% for RSUs granted in 2017. 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 three-year period.

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

Year Ended December 31,	2017	2016	2015
RSUs vested during the year	1,337	1,063	954
RSUs converted during the year, net of shares withheld for taxes	865	705	1,238
Shares withheld for taxes	472	358	549

OTHER SHARE BASED COMPENSATION

The Company has three other share-based award programs. The Company has recorded expenses of $8 million, $10 million and $8 million for 2017, 2016 and 2015, respectively, related to these programs.

Stock options — AES grants options to purchase shares of common stock under stock option plans to employees and non-employee directors. Under the terms of the plans, the Company may issue options to purchase shares of the Company's common stock at a price equal to 100% of the market price at the date the option is granted. Stock options issued in 2015 have a three-year vesting schedule and vest in one-third increments over the three-year period. The stock options have a contractual term of ten years. In all circumstances, stock options granted by AES do not entitle the holder the right, or obligate AES, to settle the stock option in cash or other assets of AES.

Performance Stock Units — In 2015, 2016 and 2017, the Company issued performance stock units ("PSUs") to officers under its long-term compensation plan. PSUs are restricted stock units; certain units awarded include a market condition and the remaining awards include performance conditions. Performance conditions are based on Company's Adjusted EBITDA targets for 2015 and Free Cash Flow targets for 2016 and 2017. For the units subject to market conditions, the total stockholder return on AES common stock must exceed the total stockholder return of the Standard and Poor's 500 Utilities Sector Index over a three-year measurement period. The market and 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 that 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 RSU in cash or other assets of AES.

Performance Cash Units — In 2016 and 2017, the Company issued Performance Cash Units ("PCUs") to its officers under its long-term compensation plan. The value of these units depends on the 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 Market Index over a three-year measurement period. Since PCUs are settled in cash, they qualify for liability accounting and periodic measurement is required.

17. REDEEMABLE STOCK OF SUBSIDIARIES

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

December 31,	2017	2016
Balance at the beginning of the period	$ 782	$ 538
Sale of redeemable stock of subsidiaries	—	134
Contributions from holders of redeemable stock of subsidiaries	50	130
Net loss attributable to redeemable stock of subsidiaries	(14)	(11)
Fair value adjustment [1]	25	4
Other comprehensive income (loss) attributable to redeemable stock of subsidiaries	(2)	6
Acquisition and reclassification of stock of subsidiaries	(4)	(19)
Balance at the end of the period	$ 837	$ 782

(1) $5 million increase in fair value of DP&L preferred shares offset by $1 million decrease in fair value of Colon common stock in 2016.

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

December 31,	2017	2016
IPALCO common stock	$ 618	$ 618
Colon quotas [1]	159	100
IPL preferred stock	60	60
Other common stock	—	4
Total redeemable stock of subsidiaries	$ 837	$ 782

(1) Characteristics of quotas are similar to common stock.

Colon — Our partner in Colon made capital contributions of $50 million and $106 million during the year ended December 31, 2017 and 2016, respectively. Any subsequent adjustments to allocate earnings and dividends to our partner, or measure the investment at fair value, will be classified as temporary equity each reporting period as it is probable that the shares will become redeemable.

IPL — IPL had $60 million of cumulative preferred stock outstanding at December 31, 2017 and 2016, which represent five series of preferred stock. The total annual dividend requirements were approximately $3 million at December 31, 2017 and 2016. Certain series of the preferred stock were redeemable solely at the option of the issuer at prices between $100 and $118 per share. Holders of the preferred stock are entitled to elect a majority of IPL's board of directors if IPL has not paid dividends to its preferred stockholders for four consecutive quarters. Based on the preferred stockholders' ability to elect a majority of IPL's board of directors in this circumstance, the redemption of the preferred shares is considered to be not solely within the control of the issuer and the preferred stock is considered temporary equity.

DPL — DPL had $18 million of cumulative preferred stock outstanding as of December 31, 2015, for which redemption became probable in September 2016. As such, the Company recorded an adjustment of $5 million to retained earnings to adjust the preferred shares to their redemption value of $23 million. In October 2016, DPL redeemed all of its preferred shares. Upon redemption, the preferred shares were no longer outstanding and all rights of the shareholders of DPL ceased to exist.

IPALCO — In February 2015, CDPQ purchased 15% of AES US Investment, Inc., a wholly-owned subsidiary of IPALCO, for $247 million, with an option to invest an additional $349 million in IPALCO through 2016 in exchange for a 17.65% equity stake. In April 2015, CDPQ invested an additional $214 million in IPALCO, which resulted in CDPQ's combined direct and indirect interest in IPALCO of 24.90%. As a result of these transactions, $84 million in taxes and transaction costs were recognized as a net decrease to equity. The Company also recognized an increase to additional paid-in-capital and a reduction to retained earnings of $377 million for the excess of the fair value of the shares over their book value. No gain or loss was recognized in net income as the transaction was not considered to be a sale of in-substance real estate.

In March 2016, CDPQ exercised its remaining option by investing $134 million in IPALCO, which resulted in CDPQ's combined direct and indirect interest in IPALCO of 30%. The Company also recognized an increase to additional paid-in-capital and a reduction to retained earnings of $84 million for the excess of the fair value of the shares over their book value. In June 2016, CDPQ contributed an additional $24 million to IPALCO, with no impact to the ownership structure of the investment. Any subsequent adjustments to allocate earnings and dividends to

CDPQ will be classified as NCI within permanent equity as it is not probable that the shares will become redeemable.

18. OTHER INCOME AND EXPENSE

Other Income — Other income generally includes gains on asset sales and liability extinguishments, favorable judgments on contingencies, gains on contract terminations, allowance for funds used during construction and other income from miscellaneous transactions. The components are summarized as follows (in millions):

Year Ended December 31,	2017	2016	2015
Legal settlements [1]	$ 60	$ —	$ —
Allowance for funds used during construction (US Utilities)	26	29	17
Gain on sale of assets	1	4	17
Contract termination	—	—	20
Other	33	31	30
Total other income	$ 120	$ 64	$ 84

(1) In December 2016, the Company and YPF entered into a settlement in which all parties agreed to give up any and all legal action related to gas supply contracts that were terminated in 2008 and have been in dispute since 2009. In January 2017, the YPF board approved the agreement and paid the Company $60 million, thereby resolving all uncertainties around the dispute.

Other Expense — Other expense generally includes losses on asset sales and dispositions, losses on legal contingencies, and losses from other miscellaneous transactions. The components are summarized as follows (in millions):

Year Ended December 31,	2017	2016	2015
Allowance for other receivables [1]	$ —	$ 52	$ —
Loss on sale and disposal of assets	28	12	—
Water rights write-off	19	6	10
Other	10	9	14
Total other expense	$ 57	$ 79	$ 24

(1) During the fourth quarter of 2016, we recognized a full allowance on a non-trade receivable in the MCAC SBU as a result of payment delays and discussions with the counterparty. The allowance relates to certain reimbursements the Company was expecting in connection with a legal matter. Management believes the counterparty is obligated to pay and plans to continue to attempt to fully collect the non-trade receivable.

19. ASSET IMPAIRMENT EXPENSE

Year ended December 31, (in millions)	2017	2016	2015
DPL	$ 175	$ 859	$ —
Laurel Mountain	121	—	—
Kazakhstan Hydroelectric	92	—	—
Kazakhstan CHPs	94	—	—
Kilroot	37	—	121
Buffalo Gap II	—	159	—
Buffalo Gap I	—	77	—
Buffalo Gap III	—	—	116
U.K. Wind	—	—	37
Other	18	1	11
Total	$ 537	$ 1,096	$ 285

Laurel Mountain — During the fourth quarter of 2017, the Company tested the recoverability of its long-lived assets at Laurel Mountain, a wind farm in the U.S. Impairment indicators were identified based on a decline in forward pricing. The Company determined that the carrying amount was not recoverable. The Laurel Mountain asset group was determined to have a fair value of $33 million using the income approach. As a result, the Company recognized an asset impairment expense of $121 million. Laurel Mountain is reported in the US SBU reportable segment.

Kilroot — During the fourth quarter of 2017, the Company tested the recoverability of its long-lived assets at Kilroot, a coal and oil-fired plant in Northern Ireland, as Kilroot was not successful in bidding its coal units into the December 2017 capacity auction for the newly implemented I-SEM market. The Company determined that the carrying amount of the asset group was not recoverable. The Kilroot asset group was determined to have a fair value of $20 million using the income approach. As a result, the Company recognized an asset impairment expense of $37 million, which was limited to the carrying value of the coal units. Kilroot is reported in the Eurasia SBU reportable segment.

During 2015, the Company tested the recoverability of long-lived assets at Kilroot when the regulator established lower capacity prices for the I-SEM. The Company determined that the carrying amount of the asset group was not recoverable. The Kilroot asset group was determined to have a fair value of $70 million using the income approach. As a result, the Company recognized asset impairment expense of $121 million. Kilroot is reported in the Eurasia SBU reportable segment.

Kazakhstan Hydroelectric — In April 2017, the Republic of Kazakhstan stated the concession agreements would not be extended for Shulbinsk HPP and Ust-Kamenogorsk HPP, two hydroelectric plants in Kazakhstan, and initiated the process to transfer these plants back to the government. Upon meeting the held-for-sale criteria in the second quarter of 2017, the Company performed an impairment analysis and determined the carrying value of the asset group of $190 million, which included cumulative translation losses of $100 million, was greater than its fair value less costs to sell of $92 million. As a result, the Company recognized asset impairment expense of $92 million limited to the carrying value of the long-lived assets. The Company completed the transfer of the plants in October 2017. Prior to their transfer, the Kazakhstan hydroelectric plants were reported in the Eurasia SBU reportable segment. See Note 22—*Held-for-Sale Businesses and Dispositions* for further information.

Kazakhstan CHPs — In January 2017, the Company entered into an agreement for the sale of Ust-Kamenogorsk CHP and Sogrinsk CHP, its combined heating and power coal plants in Kazakhstan. Upon meeting the held-for-sale criteria in the first quarter of 2017, the Company performed an impairment analysis and determined that the carrying value of the asset group of $171 million, which included cumulative translation losses of $92 million, was greater than its fair value less costs to sell of $29 million. As a result, the Company recognized asset impairment expense of $94 million limited to the carrying value of the long-lived assets. The Company completed the sale of its interest in the Kazakhstan CHP plants in April 2017. Prior to their sale, the plants were reported in the Eurasia SBU reportable segment. See Note 22—*Held-for-Sale Businesses and Dispositions* for further information.

DPL — In March 2017, the Board of Directors of DPL approved the retirement of the DPL operated and co-owned Stuart coal-fired and diesel-fired generating units, and the Killen coal-fired generating unit and combustion turbine on or before June 1, 2018. The Company performed an impairment analysis and determined that the carrying amounts of the facilities were not recoverable. The Stuart and Killen asset groups were determined to have fair values of $3 million and $8 million, respectively, using the income approach. As a result, the Company recognized total asset impairment expense of $66 million. DPL is reported in the US SBU reportable segment.

In December 2017, DPL entered into an agreement for the sale of six of its combustion turbine and diesel-fired generation facilities and related assets ("DPL peaker assets"). Upon meeting the held-for-sale criteria, the Company performed an impairment analysis and determined that the carrying value of the asset group of $346 million was greater than its fair value less costs to sell of $237 million. As a result, the Company recognized asset impairment expense of $109 million. The DPL peaker assets are reported in the US SBU reportable segment. See Note 22—*Held-for-Sale Businesses and Dispositions* for further information.

During the second quarter of 2016, the Company tested the recoverability of its long-lived generation assets at DPL. Uncertainty created by the Supreme Court of Ohio's June 20, 2016 opinion regarding ESP 2, lower expectations of future revenue resulting from the most recent PJM capacity auction and higher anticipated environmental compliance costs resulting from third party studies were collectively determined to be an impairment indicator for these assets. The Company performed an impairment analysis and determined that the carrying amount of Killen, a coal-fired generation facility, and certain DPL peaking generation facilities were not recoverable. The Killen and DPL peaking generation asset groups were determined to have a fair value of $84 million and $5 million, respectively, using the income approach. As a result, the Company recognized total asset impairment expense of $235 million. DPL is reported in the US SBU reportable segment.

During the fourth quarter of 2016, the Company tested the recoverability of its long-lived coal-fired generation assets and one gas-fired peaking plant at DPL. Uncertainty around the useful life of Stuart and Killen related to the Company's ESP proceedings and lower forward dark spreads and capacity prices were collectively determined to be an impairment indicator for these assets. Market information indicating a significant decrease in the fair value of Zimmer and Miami Fort was determined to be an indicator of impairment for these assets. The lower forward dark spreads and capacity prices, along with the indicators at the other coal-fired facilities, collectively, resulted in an indicator of impairment for the Conesville asset group. For the gas-fired peaking plant, significant incremental capital expenditures relative to its fair value, and an impairment charge taken at this facility in the second quarter of 2016, were collectively determined to be impairment indicators for this asset. The Company performed an impairment analysis for each of these asset groups and determined that their carrying amounts were not recoverable. The Stuart, Killen, Miami Fort, Zimmer, Conesville and the gas-fired peaking plant asset groups were determined to have fair values of $57 million, $43 million, $36 million, $24 million, $1 million and $2 million, respectively, using the market approach for Miami Fort and Zimmer and the income approach for the remaining asset groups. As a result, the Company recognized total asset impairment expense of $624 million. DPL is reported in the US SBU reportable segment.

Buffalo Gap I — During 2016, the Company tested the recoverability of its long-lived assets at Buffalo Gap I. Low wind production during 2016 resulted in management lowering future expectations of production and therefore future forecasted revenues. As such this was determined to be an impairment indicator. The Company determined that the carrying amount of the asset group was not recoverable. The Buffalo Gap I asset group was determined to have a fair value of $36 million using the income approach. As a result, the Company recognized asset impairment expense of $77 million ($23 million attributable to AES). Buffalo Gap I is reported in the US SBU reportable segment.

Buffalo Gap II — During 2016, the Company tested the recoverability of its long-lived assets at Buffalo Gap II. Impairment indicators were identified based on a decline in forward power curves. The Company determined that the carrying amount was not recoverable. The Buffalo Gap II asset group was determined to have a fair value of $92 million using the income approach. As a result, the Company recognized asset impairment expense of $159 million ($49 million attributable to AES). Buffalo Gap II is reported in the US SBU reportable segment.

Buffalo Gap III — During 2015, the Company tested the recoverability of its long-lived assets at Buffalo Gap III, a wind farm in Texas. Impairment indicators were identified based on a decline in forward power curves coupled with the near term expiration of favorable contracted cash flows. The Company determined that the carrying amount was not recoverable. The Buffalo Gap III asset group was determined to have a fair value of $118 million using the income approach. As a result, the Company recognized asset impairment expense of $116 million. Buffalo Gap III is reported in the US SBU reportable segment.

U.K. Wind — During 2015, the Company decided to no longer pursue two wind projects in the U.K. based on regulatory clarifications specific to these projects, resulting in a full impairment. Impairment indicators were also identified at four other wind projects based on their current development status and a reassessment of the likelihood that each project would be pursued given aviation concerns, regulatory changes, economic considerations and other factors. The Company determined that the carrying amounts of each of these asset groups, which totaled $38 million, were not recoverable. In aggregate, the asset groups were determined to have a fair value of $1 million using the market approach and, as a result, the Company recognized asset impairment expense of $37 million. The U.K. Wind Projects are reported in the Eurasia SBU reportable segment. See Note 22—*Held-for-Sale Businesses and Dispositions* for further information.

20. INCOME TAXES

U.S. Tax Reform — On December 22, 2017, the U.S. enacted the Tax Cuts and Jobs Act (the “2017 Act”). The 2017 Act significantly changes U.S. corporate income tax law. Among other changes effective in 2017, the 2017 Act requires companies to pay a one-time tax on certain unrepatriated earnings of foreign subsidiaries.

The Company recognized the income tax effects of the 2017 Act in accordance with Staff Accounting Bulletin No. 118 (“SAB 118”) which provides SEC guidance on the application of ASC 740, *Income Taxes*, in the reporting period in which the 2017 Act was signed into law. Accordingly, the Company’s financial statements reflect provisional amounts for those impacts for which the accounting under ASC 740 is incomplete, but a reasonable estimate could be determined.

The Company has calculated its best estimate of the impact of the 2017 Act in its income tax provision for the year ended December 31, 2017 in accordance with its understanding of the 2017 Act and guidance available as of the date of this filing, and as a result recognized $714 million of tax expense in the fourth quarter of 2017.

This total includes a provisional tax expense of $39 million related to the remeasurement of certain deferred tax assets and liabilities from 35% to 21%. The most material deferred taxes to be remeasured related to net operating losses (after reduction for the one-time transition tax) and property, plant and equipment. Additional time is required to finalize remeasurement effects. In accordance with U.S. GAAP, the remeasurement of deferred tax assets and liabilities related to regulated utilities was recorded as a regulatory liability.

The fourth quarter impact also includes provisional tax expense of $675 million related to the one-time transition tax on the deemed repatriation of foreign earnings. The calculation of the one-time tax is quite complex, requiring determinations of liquid asset balances over three years, determination of foreign earnings and profits ("E&P," a U.S. tax measure) at multiple dates, and multiple other computations. Our estimated tax expense was impacted by cash and restricted cash balances at foreign subsidiaries, unbilled receivables, and other liquid assets taxable at a 15.5% rate and the balance of non-cash E&P taxable at 8%. We anticipate further guidance on the determination of fair value for federal tax purposes of the shares we hold in our publicly traded subsidiaries, which are considered components of our foreign subsidiaries' "cash position" and taxed at the 15.5% rate, and may materially impact our provisional estimate. The one-time transition tax had a significant impact on our 2017 effective tax rate and utilized approximately $1.9 billion or 51% of our U.S. net operating losses. The ultimate impact may differ from these provisional amounts, possibly materially, due to, among other things, additional analysis, changes in interpretations and assumptions the Company has made, additional regulatory guidance that may be issued, and actions the Company may take as a result of the 2017 Act. The accounting is expected to be complete when the 2017 U.S. corporate income tax return is filed in 2018.

Argentine Tax Reform — In December 2017, the Argentine government enacted reforms to its income tax laws that resulted in a decrease to statutory income tax rates for our Argentine businesses from 35% to 30% in 2018-2019 and to 25% for 2020 and future years. The impact of remeasuring deferred taxes to account for the enacted change in future applicable income tax rates was recognized as income tax benefit in the fourth quarter of 2017, resulting in a decrease of $21 million to consolidated income tax expense.

Chilean Tax Reform — In February 2016, the Chilean government enacted further reforms to its income tax laws that resulted in an increase to statutory income tax rates for most of our Chilean businesses from 25% to 25.5% in 2017 and to 27% for 2018 and future years. The impact of remeasuring deferred taxes to account for the enacted change in future applicable income tax rates was recognized as a discrete income tax expense in the first quarter of 2016, resulting in an increase of $26 million to consolidated income tax expense.

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

December 31,		2017	2016	2015
Federal:	Current	$ —	$ 2	$ 9
	Deferred	545	(361)	(63)
State:	Current	—	1	1
	Deferred	1	(4)	(5)
Foreign:	Current	335	318	470
	Deferred	109	76	—
Total		$ 990	$ 32	$ 412

Effective and Statutory Rate Reconciliation — The following table summarizes a reconciliation of the U.S. statutory federal income tax rate to the Company's effective tax rate as a percentage of income from continuing operations before taxes for the periods indicated:

December 31,	2017	2016	2015
Statutory Federal tax rate	35 %	35 %	35 %
State taxes, net of Federal tax benefit	(7)%	(18)%	(6)%
Taxes on foreign earnings	— %	(46)%	5 %
Valuation allowance	10 %	10 %	(5)%
Uncertain tax positions	— %	4 %	(1)%
Noncontrolling Interest on Buffalo Gap impairments	— %	31 %	3 %
Change in tax law	90 %	12 %	— %
Goodwill impairment	— %	— %	11 %
Other—net	— %	(11)%	— %
Effective tax rate	128 %	17 %	42 %

For 2017, the 90% change in tax law item relates primarily to the impact of U.S. and Argentina tax reform enacted in the current period. The impact of the U.S one-time transition tax and remeasurement of deferred taxes represents 88% and 5%, respectively, which is partially offset by the tax benefit resulting from Argentina tax reform representing 3%.

For 2016, the 31% Buffalo Gap impairments item relates to the amounts of impairment allocated to noncontrolling interest which is nondeductible.

Income Tax Receivables and Payables — The current income taxes receivable and payable are included in *Other Current Assets* and *Accrued and Other Liabilities*, respectively, on the accompanying Consolidated Balance Sheets. The noncurrent income taxes receivable and payable are included in Other Noncurrent Assets and Other Noncurrent Liabilities, respectively, on the accompanying Consolidated Balance Sheets. The following table summarizes the income taxes receivable and payable as of the periods indicated (in millions):

December 31,	2017	2016
Income taxes receivable—current	$ 147	$ 136
Total income taxes receivable	$ 147	$ 136
Income taxes payable—current	$ 129	$ 149
Income taxes payable—noncurrent	17	22
Total income taxes payable	$ 146	$ 171

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, 2017, the Company had federal net operating loss carryforwards for tax purposes of approximately $1.9 billion expiring in years 2027 to 2036. The Company also had federal general business tax credit carryforwards of approximately $21 million expiring primarily from 2021 to 2037, and federal alternative minimum tax credits of approximately $5 million that may be fully recovered by 2021 under the 2017 Act. The Company had state net operating loss carryforwards as of December 31, 2017 of approximately $9.3 billion expiring in years 2018 to 2037. As of December 31, 2017, the Company had foreign net operating loss carryforwards of approximately $2.8 billion that expire at various times beginning in 2018 and some of which carry forward without expiration, and tax credits available in foreign jurisdictions of approximately $28 million, $18 million of which expire in 2021, $1 million of which expire in years 2023 to 2028, and $9 million of which carry forward without expiration.

Valuation allowances increased $112 million during 2017 to $988 million at December 31, 2017. This net increase was primarily the result of valuation allowance activity at certain of our Brazil subsidiaries.

Valuation allowances decreased $18 million during 2016 to $876 million at December 31, 2016. This net decrease was primarily the result of valuation allowance releases and foreign exchange gains at certain of our Brazil subsidiaries.

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,	2017	2016
Differences between book and tax basis of property	$ (1,424)	$ (1,926)
Other taxable temporary differences	(143)	(335)
Total deferred tax liability	(1,567)	(2,261)
Operating loss carryforwards	1,439	2,088
Capital loss carryforwards	63	59
Bad debt and other book provisions	66	96
Tax credit carryforwards	51	54
Other deductible temporary differences	60	263
Total gross deferred tax asset	1,679	2,560
Less: valuation allowance	(988)	(876)
Total net deferred tax asset	691	1,684
Net deferred tax (liability)	$ (876)	$ (577)

The Company considers undistributed earnings of certain foreign subsidiaries to be indefinitely reinvested outside of the U.S. Except for the one-time transition tax in the U.S., no taxes have been recorded with respect to our indefinitely reinvested earnings in accordance with the relevant accounting guidance for income taxes. Should the earnings be remitted as dividends, the Company may be subject to additional foreign withholding and state income taxes. Under the 2017 Act, generally future distributions from foreign subsidiaries will be subject to a dividends received deduction in the U.S. As of December 31, 2017, the cumulative amount of U.S. GAAP foreign un-remitted earnings upon which additional income taxes have not been provided is approximately $4 billion. It is not practicable to estimate the amount of any additional taxes which may be payable on the undistributed earnings.

Income from operations in certain countries is subject to reduced tax rates as a result of satisfying specific commitments regarding employment and capital investment. The Company's income tax benefits related to the tax status of these operations are estimated to be $26 million, $20 million and $21 million for the years ended December 31, 2017, 2016 and 2015, respectively. The per share effect of these benefits after noncontrolling interests was $0.03, $0.02 and $0.02 for the years ended December 31, 2017, 2016 and 2015, respectively. Included in the Company's income tax benefits is the benefit related to our operations in Vietnam, which is estimated to be $13 million, $15 million and $8 million for the years ended December 31, 2017, 2016 and 2015, respectively. The per share effect of these benefits related to our operations in Vietnam after noncontrolling interest was $0.01, $0.01 and $0.01 for the years ended December 31, 2017, 2016 and 2015, respectively.

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,	2017	2016	2015
U.S.	$ (511)	$ (1,305)	$ (612)
Non-U.S.	1,282	1,492	1,601
Total	$ 771	$ 187	$ 989

Uncertain Tax Positions — Uncertain tax positions have been classified as noncurrent income tax liabilities unless they are expected to be paid in 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,	2017	2016
Interest related	$ 7	$ 6
Penalties related	—	—

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

December 31,	2017	2016	2015
Total expense (benefit) for interest related to unrecognized tax benefits	$ 1	$ 2	$ (2)
Total expense for penalties related to unrecognized tax benefits	—	—	—

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	2011-2017
Brazil	2012-2017
Chile	2014-2017
Colombia	2015-2017
Dominican Republic	2015-2017
El Salvador	2014-2017
Netherlands	2014-2017
Philippines	2013-2017
United Kingdom	2012-2017
United States (Federal)	2014-2017

As of December 31, 2017, 2016 and 2015, the total amount of unrecognized tax benefits was $348 million, $352 million and $364 million, respectively. The total amount of unrecognized tax benefits that would benefit the effective tax rate as of December 31, 2017, 2016 and 2015 is $332 million, $332 million and $343 million, respectively, of which $29 million, $24 million and $24 million, respectively, would be in the form of tax attributes that would warrant a full valuation allowance.

The total amount of unrecognized tax benefits anticipated to result in a net decrease to unrecognized tax benefits within 12 months of December 31, 2017 is estimated to be between $5 million and $15 million, primarily relating to statute of limitation lapses and tax exam settlements.

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

December 31,	2017	2016	2015
Balance at January 1	$ 352	$ 364	$ 384
Additions for current year tax positions	—	2	2
Additions for tax positions of prior years	2	1	12
Reductions for tax positions of prior years	(5)	(1)	(7)
Effects of foreign currency translation	—	—	(3)
Settlements	—	(13)	(17)
Lapse of statute of limitations	(1)	(1)	(7)
Balance at December 31	$ 348	$ 352	$ 364

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, 2017. Our effective tax rate and net income in any given future period could therefore be materially impacted.

21. DISCONTINUED OPERATIONS

Due to a portfolio evaluation in the first half of 2016, management decided to pursue a strategic shift of its distribution companies in Brazil, Sul and Eletropaulo, to reduce the Company's exposure to the Brazilian distribution market.

Eletropaulo — In November 2017, Eletropaulo converted its preferred shares into ordinary shares and transitioned the listing of those shares into the Novo Mercado, which is a listing segment of the Brazilian stock exchange with the highest standards of corporate governance. Upon conversion of the preferred shares into ordinary shares, AES no longer controlled Eletropaulo, but maintained significant influence over the business. As a result, the Company deconsolidated Eletropaulo. After deconsolidation, the Company's 17% ownership interest is reflected as an equity method investment. The Company recorded an after-tax loss on deconsolidation of $611 million, which primarily consisted of $455 million related to cumulative translation losses and $243 million related to pension losses reclassified from AOCL.

In December 2017, all the remaining criteria were met for Eletropaulo to qualify as a discontinued operation. Therefore, its results of operations and financial position were reported as such in the consolidated financial statements for all periods presented. Eletropaulo's pre-tax loss attributable to AES, including the loss on deconsolidation, for the years ended December 31, 2017 and 2016 was $633 million and $192 million, respectively. Eletropaulo's pre-tax income attributable to AES for the year ended December 31, 2015 was $73 million. Prior to its classification as discontinued operations, Eletropaulo was reported in the Brazil SBU reportable segment.

Sul — The Company executed an agreement for the sale of Sul, a wholly-owned subsidiary, in June 2016. The results of operations and financial position of Sul are reported as discontinued operations in the consolidated financial statements for all periods presented. Upon meeting the held-for-sale criteria, the Company recognized an after-tax loss of $382 million comprised of a pre-tax impairment charge of $783 million, offset by a tax benefit of $266 million related to the impairment of the Sul long lived assets and a tax benefit of $135 million for deferred taxes related to the investment in Sul. Prior to the impairment charge, the carrying value of the Sul asset group of $1.6 billion was greater than its approximate fair value less costs to sell. However, the impairment charge was limited to the carrying value of the long lived assets of the Sul disposal group.

On October 31, 2016, the Company completed the sale of Sul and received final proceeds less costs to sell of $484 million, excluding contingent consideration. Upon disposal of Sul, the Company incurred an additional after-tax loss on sale of $737 million. The cumulative impact to earnings of the impairment and loss on sale was $1.1 billion. This includes the reclassification of approximately $1 billion of cumulative translation losses resulting in a net reduction to the Company's stockholders' equity of $92 million.

Sul's pre-tax loss attributable to AES for the years ended December 31, 2016 and 2015 was $1.4 billion and $32 million, respectively. Prior to its classification as discontinued operations, Sul was reported in the Brazil SBU reportable segment.

The following table summarizes the carrying amounts of the major classes of assets and liabilities of discontinued operations at December 31, 2017 and December 31, 2016:

(in millions)	December 31, 2017	December 31, 2016
Assets of discontinued operations and held-for-sale businesses:		
Cash and cash equivalents	$ —	$ 61
Short-term investments	—	268
Accounts receivable, net of allowance for doubtful accounts of $0 and $94, respectively	—	745
Other current assets	—	499
Property, plant and equipment and intangibles, net	—	2,504
Investments in and advances to affiliates [1]	86	—
Deferred income taxes	—	554
Other classes of assets that are not major	—	305
Total assets of discontinued operations	$ 86	$ 4,936
Other assets of businesses classified as held-for-sale [2]	1,948	—
Total assets of discontinued operations and held-for-sale businesses [3]	$ 2,034	$ 4,936
Liabilities of discontinued operations and held-for-sale businesses:		
Accounts payable	$ —	$ 418
Accrued and other liabilities	—	954
Non-recourse debt	—	1,009
Pension and other postretirement liabilities	—	1,159
Other noncurrent liabilities	—	678
Other classes of liabilities that are not major	—	31
Total liabilities of discontinued operations	$ —	$ 4,249
Other liabilities of businesses classified as held-for-sale [2]	1,033	—
Total liabilities of discontinued operations and held-for-sale businesses [3]	$ 1,033	$ 4,249

(1) Represents the Company's 17% ownership interest in Eletropaulo.
(2) Masinloc, Eletrica Santiago, and the DPL peaker assets were classified as held-for-sale as of December 31, 2017. See Note 22—*Held-for-Sale Businesses and Dispositions* for further information.
(3) Amounts at December 31, 2016 are classified as both current and long-term on the Consolidated Balance Sheet.

The following table summarizes the major line items constituting *losses from discontinued operations* for the periods indicated (in millions):

December 31,	2017	2016	2015
Income (loss) from discontinued operations, net of tax:			
Revenue — regulated	$ 3,320	$ 4,036	$ 4,430
Cost of sales	(3,151)	(3,954)	(4,227)
Other income and expense items that are not major [1]	(166)	(160)	(70)
Income (loss) from operations of discontinued businesses	3	(78)	133
Loss from disposal and impairments of discontinued businesses	(611)	(1,385)	—
Income (loss) from discontinued operations	(608)	(1,463)	133
Less: Net income attributable to noncontrolling interests	(25)	(142)	(92)
Income (loss) from discontinued operations attributable to The AES Corporation	(633)	(1,605)	41
Income tax benefit (expense)	(21)	495	(53)
Loss from discontinued operations, net of tax	$ (654)	$ (1,110)	$ (12)

(1) Includes a loss contingency recognized by our equity method investment in discontinued operations.

The following table summarizes the operating and investing cash flows from discontinued operations for the periods indicated (in millions):

December 31,	2017	2016	2015
Cash flows provided by (used in) operating activities of discontinued operations	$ 164	$ 529	$ (125)
Cash flows used in investing activities of discontinued operations	(288)	(368)	(65)

22. HELD-FOR-SALE BUSINESSES AND DISPOSITIONS

Held-for-Sale Businesses

Masinloc — In December 2017, the Company entered into an agreement to sell its entire 51% equity interest in Masinloc for approximately $1 billion, subject to customary purchase price adjustments. Masinloc consists of a coal-fired generation plant in operation, a coal-fired generation plant currently under construction, and an energy storage facility all located in the Philippines. Closing of the sale is expected during the first half of 2018, subject to certain regulatory approvals. As of December 31, 2017, Masinloc was classified as held-for-sale, but did not meet the criteria to be reported as discontinued operations. On a consolidated basis, the net carrying value of Masinloc at December 31, 2017 was $475 million. Masinloc is reported in the Eurasia SBU reportable segment.

In 2014, the Company completed the sale of 45% of its ownership interest in Masinloc for $436 million, including $23 million of consideration that was contingent upon the achievement of certain tax restructuring efficiencies. The transaction was accounted for as a sale of in-substance real estate. In December 2017, the related contingency expired and the $23 million of contingent consideration was recognized as a gain in *Gain (loss) on disposal and sale of businesses* in the Consolidated Statement of Operations.

Electrica Santiago — In December 2017, AES Gener entered into an agreement to sell Electrica Santiago, comprised of four gas and diesel-fired generation plants in Chile, for $300 million, subject to customary purchase price adjustments. The sale is expected to close during the first half of 2018, subject to conditions precedent in the agreement. As of December 31, 2017, Electrica Santiago was classified as held-for-sale, but did not meet the criteria to be reported as discontinued operations. Electrica Santiago's carrying value at December 31, 2017 was $186 million. Electrica Santiago is reported in the Andes SBU reportable segment.

DPL Peaker Assets — In December 2017, DPL entered into an agreement to sell six of its combustion turbine and diesel-fired generation facilities and related assets ("DPL peaker assets") for $241 million, subject to purchase price adjustments. The sale is subject to regulatory approvals, and is expected to close in the first half of 2018. As of December 31, 2017, the DPL peaker assets were classified as held-for-sale but did not meet the criteria to be reported as discontinued operations. After impairment, the net carrying value of the DPL peaker assets at December 31, 2017 was $237 million. The DPL peaker assets are reported in the US SBU reportable segment. See Note 19—*Asset Impairment Expense* for further information.

Excluding any impairment charges or gain/loss on sale, pre-tax income attributable to AES of businesses held-for-sale as of December 31, 2017 was as follows (in millions):

Year Ended December 31,	2017	2016	2015
Masinloc	$ 103	$ 103	$ 99
Electrica Santiago	9	11	10
DPL Peaker Assets	17	20	24
Total	$ 129	$ 134	$ 133

Dispositions

Zimmer and Miami Fort — In December 2017, DPL and AES Ohio Generation completed the sale of Zimmer and Miami Fort, two coal-fired generating plants, for net proceeds of $70 million, resulting in a gain on sale of $13 million. The sale did not meet the criteria to be reported as discontinued operations. Prior to their sale, Zimmer and Miami Fort were reported in the US SBU reportable segment.

Kazakhstan Hydroelectric — Affiliates of the Company (the "Affiliates") previously operated Shulbinsk HPP and Ust-Kamenogorsk HPP (the "HPPs"), two hydroelectric plants in Kazakhstan, under a concession agreement with the Republic of Kazakhstan ("RoK"). In April 2017, the RoK initiated the process to transfer these plants back to the RoK. The RoK indicated that arbitration would be necessary to determine the correct Return Share Transfer Payment ("RST") and, rather than paying the Affiliates, deposited the RST into an escrow account. In exchange, the Affiliates transferred 100% of the shares in the HPPs to the RoK, under protest and with a full reservation of rights. The Company recorded a loss on disposal of $33 million in the fourth quarter of 2017. In February 2018, the Affiliates initiated the arbitration process in international court to recover at least $75 million of the RST placed in escrow, based on the September 30, 2017 RST calculation. Additional losses may be incurred if some or all of the disputed consideration is not paid by the RoK via a mutually acceptable settlement, or upon any unfavorable decision rendered by the arbiter. The transfer did not meet the criteria to be reported as discontinued operations. Prior to their transfer, the Kazakhstan HPPs were reported in the Eurasia SBU reportable segment. See Note 19—*Asset Impairment Expense* for further information.

Kazakhstan CHPs — In April 2017, the Company completed the sale of Ust-Kamenogorsk CHP and Sogrinsk CHP, its combined heating and power coal plants in Kazakhstan, for net proceeds of $24 million. The Company recognized a pre-tax loss on sale of $49 million, primarily related to cumulative translation losses. The sale did not meet the criteria to be reported as discontinued operations. Prior to their sale, the Kazakhstan CHP plants were reported in the Eurasia SBU reportable segment. See Note 19—*Asset Impairment Expense* for further information.

U.K. Wind — During the second quarter of 2016, the Company deconsolidated UK Wind and recorded a loss on deconsolidation of $20 million to *Gain (loss) on disposal and sale of businesses* in the Consolidated Statement of Operations. Prior to deconsolidation, UK Wind was reported in the Eurasia SBU reportable segment. See Note 14—*Equity* and Note 19—*Asset Impairment Expense* for further information.

DPLER — In January 2016, the Company completed the sale of DPLER, a competitive retail marketer selling electricity to customers in Ohio, and recognized a gain on sale of $49 million. Proceeds of $76 million were received in December 2015. DPLER did not meet the criteria to be reported as a discontinued operation. DPLER's results were therefore reflected within continuing operations in the Consolidated Statements of Operations. Prior to its sale, DPLER was reported in the US SBU reportable segment.

Kelanitissa — In January 2016, the Company completed the sale of its interest in Kelanitissa, a diesel-fired generation plant in Sri Lanka, for $18 million, resulting in a loss on sale of $5 million. The sale did not meet the criteria to be reported as discontinued operations. Kelanitissa's results were therefore reflected within continuing operations in the Consolidated Statements of Operations. Prior to its sale, Kelanitissa was reported in the Eurasia SBU reportable segment.

Armenia Mountain — Under the terms of the sale agreement for certain U.S. Wind Projects, the buyer was provided an option to purchase the Company's 100% interest in Armenia Mountain, a wind project in Pennsylvania, for $75 million. The buyer exercised this option and AES completed the sale of Armenia Mountain in July 2015. The sale did not meet the criteria to be reported as discontinued operations. Upon completion, net proceeds of $64 million were received and a pre-tax gain on sale of $22 million was recognized. Prior to its sale, Armenia Mountain was reported in the US SBU reportable segment.

Excluding any impairment charge or gain/loss on sale, pre-tax income (loss) attributable to AES of disposed businesses was as follows (in millions):

Year Ended December 31,	**2017**	**2016**	**2015**
Zimmer and Miami Fort	$ 26	$ (14)	$ 6
Kazakhstan Hydroelectric	33	34	52
Kazakhstan CHPs	13	12	16
DPLER	—	—	11
Armenia Mountain	—	—	6
Total	$ 72	$ 32	$ 91

23. ACQUISITIONS

Alto Sertão II — On August 3, 2017, the Company completed the acquisition of 100% of the Alto Sertão II Wind Complex ("Alto Sertão II") from Renova Energia S.A. for $181 million, subject to customary purchase price adjustments, plus the assumption of $348 million of non-recourse debt, and up to $30 million of contingent consideration. At closing, the Company made an initial cash payment of $143 million, which excludes holdbacks related to indemnifications and purchase price adjustments. As of December 31, 2017, the purchase price allocation for Alto Sertão II is preliminary. The Company is in the process of assessing the fair value of the assets acquired and liabilities assumed in the acquisition, and expects to complete the purchase price allocation within the one year measurement period. Alto Sertão II is a wind farm reported in the Brazil SBU reportable segment.

Bauru Solar Complex — On September 25, 2017, AES Tietê executed an investment agreement with Cobra do Brasil to provide approximately $140 million of non-convertible debentures in project financing for the construction of photovoltaic solar plants in Brazil. As of December 31, 2017, approximately $45 million of non-convertible debentures have been executed and distributed to the project. Upon completion of the project, expected in the first half of 2018 and subject to the solar plants' compliance with certain technical specifications defined in the agreement, Tietê expects to acquire the solar complex in exchange for the non-convertible debentures and an additional investment of approximately $55 million.

Distributed Energy — On February 18, 2015, the Company completed the acquisition of 100% of the common stock of Main Street Power Company, Inc. for approximately $25 million. The purchase consideration was composed of $20 million cash. After the date of acquisition, Main Street Power Company, Inc. was renamed Distributed Energy, Inc.

In September 2016, Distributed Energy acquired the equity interest of various projects held by multiple partnerships for approximately $43 million. These partnerships were previously classified as equity method investments. In accordance with the accounting guidance for business combinations, the Company has recorded the opening balance sheets of the acquired businesses based on the purchase price allocation as of the acquisition date.

24. 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 restricted stock units, stock options and convertible securities. The effect of such potential common stock is computed using the treasury stock method or the if-converted method, as applicable.

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, 2017, 2016 and 2015, where income represents the numerator and weighted-average shares represent the denominator. Values are in millions except per share data:

Year Ended December 31,	2017			2016			2015		
	Loss	Shares	$ per Share	Loss	Shares	$ per Share	Income	Shares	$ per Share
BASIC EARNINGS PER SHARE									
Income (loss) from continuing operations attributable to The AES Corporation common stockholders [1]	$ (507)	660	$ (0.77)	$ (25)	660	$ (0.04)	$ 318	687	$ 0.46
EFFECT OF DILUTIVE SECURITIES									
Restricted stock units	—	—	—	—	—	—	—	2	—
DILUTED EARNINGS PER SHARE	$ (507)	660	$ (0.77)	$ (25)	660	$ (0.04)	$ 318	689	$ 0.46

(1) Loss from continuing operations, net of tax, of $20 million less the $5 million adjustment to retained earnings to record the DP&L redeemable preferred stock at its redemption value as of December 31, 2016.

The calculation of diluted earnings per share excluded 7 million, 8 million and 8 million stock awards outstanding for the years ended December 31, 2017, 2016 and 2015, respectively, that could potentially dilute basic earnings per share in the future. Additionally, for the years ended December 31, 2016 and 2015, all 15 million convertible debentures were omitted from the earnings per share calculation. The Company redeemed all of its existing TECONs in June 2017. The stock awards and convertible debentures were excluded from the calculation because they were anti-dilutive.

25. RISKS AND UNCERTAINTIES

AES is a diversified power generation and utility company organized into five market-oriented SBUs. See additional discussion of the Company's principal markets in Note 15—*Segment and Geographic Information*. Within our five SBUs, we have two primary lines of business: Generation and Utilities. The Generation line of business uses a wide range of fuels and technologies to generate electricity such as coal, gas, hydro, wind, solar and biomass. Our Utilities business comprises businesses that transmit, distribute, and in certain circumstances, generate power. In addition, the Company has operations in the renewables area. These efforts include projects primarily in wind and solar.

Operating and Economic Risks — The Company operates in several developing economies where macroeconomic conditions are usually more volatile than developed economies. Deteriorating market conditions often 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. 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 a below-investment grade rating from Standard & Poor's of BB-. This could affect the Company's ability to finance new and/or existing development projects at competitive interest rates. As of December 31, 2017, the Company had $949 million of unrestricted cash and cash equivalents.

During 2017, 69% 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 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;
- difficulties in enforcing our contractual rights, enforcing judgments, or obtaining a just result in local jurisdictions; and
- potentially adverse tax consequences of operating in multiple jurisdictions.

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.

Alto Maipo — The Company's subsidiary, AES Gener, is currently constructing Alto Maipo, a hydroelectric facility near Santiago Chile. Increased project costs, or delays in construction, at Alto Maipo could have an adverse impact on the Company. Alto Maipo has experienced construction difficulties, which have resulted in an increase in projected costs over the original $2 billion budget. These overages led to a series of negotiations with the intention of restructuring the project's existing financial structure and obtaining additional funding. On March 17, 2017, AES Gener completed the legal and financial restructuring of Alto Maipo, and through the Company's 67% ownership interest in AES Gener, AES now has an effective 62% indirect economic interest in Alto Maipo. See Note 14—*Equity* for additional information regarding the restructuring.

Following the restructuring described above, the project continued to face construction difficulties, including greater than expected costs and slower than anticipated productivity by construction contractors toward agreed-upon milestones. Furthermore, during the second quarter of 2017, as a result of the failure to perform by one of its construction contractors, Constructora Nuevo Maipo S.A. ("CNM"), Alto Maipo terminated CNM's contract. As a result of the termination of CNM, Alto Maipo's construction debt of $618 million and derivative liabilities of $132 million are in technical default and presented as current in the balance sheet as of December 31, 2017.

Construction at the project is continuing and the project is over 61% complete. In February 2018, Alto Maipo signed an amended EPC contract with Strabag, the permanent replacement contractor selected to complete CNM's work, subject to approval by the project's senior lenders as part of the second refinancing. Alto Maipo is working to resolve the challenges described above, however, there can be no assurance that Alto Maipo will succeed in these efforts and if there are further delays or cost overruns, or if Alto Maipo is unable to reach an agreement with the non-recourse lenders, there is a risk these lenders may seek to exercise remedies available as a result of the default noted above, or Alto Maipo may not be able to meet its contractual or other obligations and may be unable to continue with the project. If any of the above occur, there could be a material impairment for the Company.

The carrying value of the long-lived assets and deferred tax assets of Alto Maipo as of December 31, 2017 was approximately $1.4 billion and $60 million, respectively. Even though certain of the construction difficulties have not been formally resolved, construction costs continue to be capitalized as management believes the project is probable of completion. Management believes the carrying value of the long-lived asset group is recoverable and was not impaired as of December 31, 2017. In addition, management believes it is more likely than not that the deferred tax assets will be realized, they could be reduced if estimates of future taxable income are decreased.

Puerto Rico — In September 2017, Puerto Rico was severely impacted by Hurricanes Irma and Maria, disrupting the operations of AES Puerto Rico and AES Ilumina. Puerto Rico's infrastructure was severely damaged, including electric infrastructure and transmission lines. The extensive structural damage caused by hurricane winds and flooding is expected to take considerable time to repair. The Company sustained modest damage to its AES Ilumina solar plant, resulting in a $2 million loss, and minor damage to its AES Puerto Rico thermal plants.

Our subsidiaries in Puerto Rico have long-term PPAs with state-owned PREPA. As a result of the hurricanes, PREPA has declared an event of Force Majeure. However, both units of AES Puerto Rico and approximately 75% of AES Ilumina are available to generate electricity which, in accordance with the PPAs, will allow AES Puerto Rico to invoice capacity, even under Force Majeure.

Due to the extensive damage from the hurricanes, energy demand in Puerto Rico has decreased and is expected to remain low until economic activity has recovered. Despite the decrease in demand, AES Puerto Rico was dispatched starting in February 2018. AES Puerto Rico continues to be the lowest cost and EPA compliant energy provider in Puerto Rico. Therefore, we expect AES Puerto Rico to continue to be a critical supplier to PREPA.

Starting prior to the hurricanes, PREPA has been facing economic challenges that could impact the Company, and on July 2, 2017, filed for bankruptcy under Title III. As a result of the bankruptcy filing, AES Puerto Rico and AES Ilumina's non-recourse debt of $365 million and $36 million, respectively, is in default and has been classified as current as of December 31, 2017. In November 2017, AES Puerto Rico signed a Forbearance and Standstill Agreement with its lenders to prevent the lenders from taking any action against the company due to the default events. This agreement will expire on March 22, 2018.

The Company's receivable balances in Puerto Rico as of December 31, 2017 totaled $86 million, of which $53 million was overdue. After the filing of Title III protection, and up until the disruption caused by the hurricanes, AES in Puerto Rico was collecting the overdue amounts from PREPA in line with historic payment patterns.

Considering the information available as of the filing date, management believes the carrying amount of our assets in Puerto Rico of $627 million is recoverable as of December 31, 2017 and no reserve on the receivables is required.

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 U.S. dollar and the following currencies could create significant fluctuations in earnings and cash flows: the Argentine peso, the Brazilian real, the Dominican Republic peso, the Euro, the Chilean peso, the Colombian peso, and the Philippine 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 2017, 2016 or 2015.

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.

26. RELATED PARTY TRANSACTIONS

Certain of our businesses in Panama and the Dominican Republic are partially owned by governments either directly or through state-owned institutions. In the ordinary course of business, these businesses enter into energy purchase and sale transactions, and transmission agreements with other state-owned institutions which are controlled by such governments. At two of our generation businesses in Mexico, the offtakers exercise significant influence, but not control, through representation on these businesses' Boards of Directors. These offtakers are also required to hold a nominal ownership interest in such businesses. In Chile, we provide capacity and energy under contractual arrangements to our investment which is accounted for under the equity method of accounting. 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,	2017	2016	2015
Revenue—Non-Regulated	$ 1,297	$ 1,100	$ 1,099
Cost of Sales—Non-Regulated	220	210	330
Interest income	8	4	25
Interest expense	36	39	33

The following table summarizes the balances receivable from and payable to related parties included in the Company's Consolidated Balance Sheets as of the periods indicated (in millions):

December 31,	2017	2016
Receivables from related parties	$ 250	$ 218
Accounts and notes payable to related parties	727	892

The Company entered into an equity transaction with our related party, Linda Group, see Note 14—*Equity* for further information.

27. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarterly Financial Data — The following tables summarize the unaudited quarterly Condensed Consolidated Statements of Operations for the Company for 2017 and 2016 (amounts in millions, except per share data). Amounts have been restated to reflect discontinued operations in all periods presented and reflect all adjustments necessary in the opinion of management for a fair statement of the results for interim periods.

Quarter Ended 2017	Mar 31	June 30	Sept 30	Dec 31
Revenue	$ 2,581	$ 2,613	$ 2,693	$ 2,643
Operating margin	554	625	642	643
Income (loss) from continuing operations, net of tax (1)	97	141	236	(622)
Income (loss) from discontinued operations, net of tax	1	9	25	(664)
Net income (loss)	$ 98	$ 150	$ 261	$ (1,286)
Net income (loss) attributable to The AES Corporation	$ (24)	$ 53	$ 152	$ (1,342)
Basic income (loss) per share:				
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 0.04	$ 0.08	$ 0.22	$ (1.03)
Income (loss) from discontinued operations attributable to The AES Corporation common stockholders, net of tax	—	—	0.01	(1.00)
Basic income (loss) per share attributable to The AES Corporation	$ 0.04	$ 0.08	$ 0.23	$ (2.03)
Diluted income (loss) per share:				
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 0.04	$ 0.08	$ 0.22	$ (1.03)
Loss from discontinued operations attributable to The AES Corporation common stockholders, net of tax	—	—	0.01	(1.00)
Diluted income (loss) per share attributable to The AES Corporation	$ 0.04	$ 0.08	$ 0.23	$ (2.03)
Dividends declared per common share	$ 0.12	$ —	$ 0.12	$ 0.25

Quarter Ended 2016	Mar 31	June 30	Sept 30	Dec 31
Revenue	$ 2,530	$ 2,452	$ 2,639	$ 2,660
Operating margin	501	556	691	632
Income (loss) from continuing operations, net of tax (2)	87	2	238	(136)
Loss from discontinued operations, net of tax	(13)	(389)	(9)	(557)
Net income (loss)	$ 74	$ (387)	$ 229	$ (693)
Net income (loss) attributable to The AES Corporation	$ 126	$ (482)	$ 175	$ (949)
Basic income (loss) per share:				
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 0.21	$ (0.15)	$ 0.26	$ (0.35)
Loss from discontinued operations attributable to The AES Corporation common stockholders, net of tax	(0.02)	(0.58)	—	(1.09)
Basic income (loss) per share attributable to The AES Corporation	$ 0.19	$ (0.73)	$ 0.26	$ (1.44)
Diluted income (loss) per share:				
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 0.20	$ (0.15)	$ 0.26	$ (0.35)
Loss from discontinued operations attributable to The AES Corporation common stockholders, net of tax	(0.01)	(0.58)	—	(1.09)
Diluted income (loss) per share attributable to The AES Corporation	$ 0.19	$ (0.73)	$ 0.26	$ (1.44)
Dividends declared per common share	$ 0.11	$ —	$ 0.11	$ 0.23

(1) Includes pre-tax impairment expense of $168 million, $90 million, $2 million and $277 million, for the first, second, third and fourth quarters of 2017, respectively. See Note 19—*Asset Impairment Expense* for further discussion.

(2) Includes pre-tax impairment expense of $159 million, $235 million, $79 million and $623 million, for the first, second, third and fourth quarters of 2016, respectively. See Note 19—*Asset Impairment Expense* for further discussion.

28. SUBSEQUENT EVENTS

Fluence — In July 2017, the Company entered into a joint venture with Siemens AG to form a global energy storage technology and services company under the name Fluence. On January 1, 2018, Siemens and AES closed on the creation of the joint venture with each party holding a 50% ownership interest. Since AES does not have the ability to control Fluence, the joint venture will be accounted for as an equity affiliate.

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, 2017, our disclosure controls and procedures were effective.

On August 3, 2017, AES completed the acquisition of the Wind Farm Alto Sertão II and as a result, assets acquired and liabilities assumed in the acquisition have been included in AES’s consolidated balance sheet as of December 31, 2017. Alto Sertão II’s total assets and total liabilities represented 1.5% and 1.4% of AES’s consolidated total assets and total liabilities, respectively, as of December 31, 2017. Alto Sertão II’s net income of $2.9 million for the period August 3, 2017 through December 31, 2017 was included in AES’s consolidated statement of operations for the year ended December 31, 2017. As permitted by the SEC guidance, Alto Sertão II’s internal controls over financial reporting have been excluded from management’s formal evaluation of the effectiveness of AES’s disclosure controls and procedures due to the timing of acquisition.

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, 2017. 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, 2017.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2017, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which appears herein.

Changes in Internal Control Over Financial Reporting:

There were no changes that occurred during the quarter ended December 31, 2017 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, 2017, 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, 2017, based on the COSO criteria.

As indicated in the accompanying Item 9A, *Management's Report on Internal Control over Financial Reporting*, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Alto Sertão II, which is included in the 2017 consolidated financial statements of the Company and constituted 1.5% and 1.9% of total and net assets, respectively, as of December 31, 2017. Alto Sertão II's net income of $2.9 million for the period August 3, 2017 through December 31, 2017 was included in the Company's consolidated statement of operations for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of Alto Sertão II.

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, 2017 and 2016, and the related consolidated statements of operations, comprehensive loss, changes in equity, and cash flows for each of the three years in the period ended December 31, 2017, of the Company, and the related notes and financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "financial statements"), and our report dated February 26, 2018, expressed an unqualified opinion thereon.

Basis for Opinion

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

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Tysons, Virginia
February 26, 2018

ITEM 9B. OTHER INFORMATION

None.

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 2018 Annual Meeting of Stockholders which the Registrant expects will be filed on or around March 9, 2018 (the "2018 Proxy Statement"):

- information regarding the directors required by this item found under the heading *Board of Directors*;
- information regarding AES' Code of Ethics found under the heading *Additional Governance Matters - AES Code of Business Conduct and Corporate Governance Guidelines*;
- information regarding compliance with Section 16 of the Exchange Act required by this item found under the heading *Additional Governance Matters - Other Governance Information - Section 16(a) Beneficial Ownership Reporting Compliance*; and
- information regarding AES' Financial Audit Committee found under the heading *Board and Committee Governance Matters - Financial Audit Committee (the "Audit Committee").*

Certain information regarding executive officers required by this Item is presented as a supplementary item in Part I hereof (pursuant to Instruction 3 to Item 401(b) of Regulation S-K). The other information required by this Item, to the extent not included above, will be contained in our 2018 Proxy Statement and is herein incorporated by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 402 of Regulation S-K is contained in the 2018 Proxy Statement under "Director Compensation" and "Executive Compensation" (excluding the information under the caption "Report of the Compensation Committee") and is incorporated herein by reference.

The information required by Item 407(e)(5) of Regulation S-K is contained under the caption "Report of the 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 2018 Proxy Statement, which information is incorporated herein by reference.

(b) Securities Authorized for Issuance under Equity Compensation Plans.

The following table provides information about shares of AES common stock that may be issued under AES' equity compensation plans, as of December 31, 2017:

Securities Authorized for Issuance under Equity Compensation Plans (As of December 31, 2017)

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders [1]	11,490,439 [2]	$ 12.75	15,290,314
Equity compensation plans not approved by security holders	—	—	—
Total	11,490,439	$ 12.75	15,290,314

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(1) The following equity compensation plans have been approved by The AES Corporation's Stockholders:

(A) The AES Corporation 2003 Long Term Compensation Plan was adopted in 2003 and provided for 17,000,000 shares authorized for issuance thereunder. In 2008, an amendment to the Plan to provide an additional 12,000,000 shares was approved by AES' stockholders, bringing the total authorized shares to 29,000,000. In 2010, an additional amendment to the Plan to provide an additional 9,000,000 shares was approved by AES' stockholders, bringing the total authorized shares to 38,000,000. In 2015, an additional amendment to the Plan to provide an additional 7,750,000 shares was approved by AES' stockholders, bringing the total authorized shares to 45,750,000. The weighted average exercise price of Options outstanding under this plan included in Column (b) is $12.75 (excluding performance stock units, restricted stock units and director stock units), with 15,290,314 shares available for future issuance).

(B) The AES Corporation 2001 Plan for outside directors adopted in 2001 provided for 2,750,000 shares authorized for issuance. There are no Options outstanding under this plan. In conjunction with the 2010 amendment to the 2003 Long Term Compensation plan, ongoing award issuance from this plan was discontinued in 2010. Any remaining shares under this plan, which are not reserved for issuance under outstanding awards, are not available for future issuance and thus the amount of 2,088,633 shares is not included in Column (c) above.

(C) The AES Corporation Second Amended and Restated Deferred Compensation Plan for directors provided for 2,000,000 shares authorized for issuance. Column (b) excludes the Director stock units granted thereunder. In conjunction with the 2010 amendment to the 2003 Long Term Compensation Plan, ongoing award issuance from this plan was discontinued in 2010 as Director stock units will be issued from the 2003 Long Term Compensation Plan. Any remaining shares under this plan, which are not reserved for issuance under outstanding awards, are not available for future issuance and thus the amount of 105,341 shares is not included in Column (c) above.

(2) Includes 4,678,447 (of which 575,721 are vested and 4,102,726 are unvested) shares underlying PSU and RSU awards (assuming performance at a median level), 1,642,551 shares underlying Director stock unit awards, and 5,169,441 shares issuable upon the exercise of Stock Option grants, for an aggregate number of 11,490,439 shares.

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

The information regarding related party transactions required by this item is included in the 2018 Proxy Statement found under the headings *Transactions with Related Persons* and *Board and Committee Governance Matters* and are incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item 14 is included in the 2018 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.

Financial Statements and Schedules:	Page
Consolidated Balance Sheets as of December 31, 2017 and 2016	107
Consolidated Statements of Operations for the years ended December 31, 2017, 2016 and 2015	108
Consolidated Statements of Comprehensive Loss for the years ended December 31, 2017, 2016 and 2015	109
Consolidated Statements of Changes in Equity for the years ended December 31, 2017, 2016 and 2015	110
Consolidated Statements of Cash Flows for the years ended December 31, 2017, 2016 and 2015	111
Notes to Consolidated Financial Statements	112
Schedules	S-2-S-7

(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	By-Laws of The AES Corporation, as amended and incorporated herein by reference to Exhibit 3.1 of the Company's Form 8-K/A filed on December 2, 2015.
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.(n).
4.(a)	Junior Subordinated Indenture, dated as of March 1, 1997, 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.(a) of the Company's Form 10-K for the year ended December 31, 2008.
4.(b)	Third Supplemental Indenture, dated as of October 14, 1999, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association is incorporated herein by reference to Exhibit 4.(b) of the Company's Form 10-K for the year ended December 31, 2008.
4.(c)	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.(d)	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.(e)	Twelfth Supplemental Indenture, dated as of October 15, 2007, between The AES Corporation and Wells Fargo Bank, National Association is incorporated herein by reference to Exhibit 4.8 of the Company's Form S-4 filed on December 7, 2007.
4.(f)	Thirteenth Supplemental Indenture, dated as of May 19, 2008, between The AES Corporation and Wells Fargo Bank, National Association is incorporated herein by reference to Exhibit 4.(l) of the Company's Form 10-K for the year ended December 31, 2008.
4.(g)	Fifteenth Supplemental Indenture, dated as of June 15, 2011, between The AES Corporation and Wells Fargo Bank, National Association is incorporated herein by reference to Exhibit 4.3 of the Company's Form 8-K filed on June 15, 2011.
4.(h)	Indenture, dated October 3, 2011, between Dolphin Subsidiary II, Inc. and Wells Fargo Bank, National Association is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on October 5, 2011.
4.(i)	Sixteenth Supplemental Indenture, dated April 30, 2013, between The AES Corporation and Wells Fargo Bank, N.A., as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on April 30, 2013 (SEC File No. 001-12291).
4.(j)	Seventeenth Supplemental Indenture, dated March 7, 2014, between The AES Corporation and Wells Fargo Bank, N.A. as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on March 7, 2014.
4.(k)	Eighteenth Supplemental Indenture, dated May 20, 2014, between The AES Corporation and Wells Fargo Bank, N.A. as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on May 20, 2014.
4.(l)	Nineteenth Supplemental Indenture, dated April 6, 2015, between The AES Corporation and Wells Fargo Bank, N.A. as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on April 6, 2015.
4.(m)	Twentieth Supplemental Indenture, dated May 25, 2016, between The AES Corporation and Wells Fargo Bank, N.A. as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on May 25, 2016.
4.(n)	Twenty-First Supplemental Indenture, dated August 28, 2017, between The AES Corporation and Deutsche Bank Trust Company, as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on August 28, 2017.
10.1	The AES Corporation Profit Sharing and Stock Ownership Plan are incorporated herein by reference to Exhibit 4(c)(1) of the Registration Statement on Form S-8 (Registration No. 33-49262) filed on July 2, 1992. (P)
10.2	The AES Corporation Incentive Stock Option Plan of 1991, as amended, is incorporated herein by reference to Exhibit 10.30 of the Company's Form 10-K for the year ended December 31, 1995 (SEC File No. 00019281). (P)
10.3	Applied Energy Services, Inc. Incentive Stock Option Plan of 1982 is incorporated herein by reference to Exhibit 10.31 of the Registration Statement on Form S-1 (Registration No. 33-40483). (P)
10.4	Deferred Compensation Plan for Executive Officers, as amended, is incorporated herein by reference to Exhibit 10.32 of Amendment No. 1 to the Registration Statement on Form S-1 (Registration No. 33-40483). (P)
10.5	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.
10.6	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.
10.7	The AES Corporation Supplemental Retirement Plan is incorporated herein by reference to Exhibit 10.63 of the Company's Form 10-K for the year ended December 31, 1994 (SEC File No. 00019281). (P)
10.7A	Amendment to The AES Corporation Supplemental Retirement Plan, dated March 13, 2008 is incorporated herein by reference to Exhibit 10.9.A of the Company's Form 10-K for the year ended December 31, 2007.

10.8	The AES Corporation 2001 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, 2000 (SEC File No. 001-12291).
10.9	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).
10.10	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).
10.10A	Amendment to the 2001 Stock Option Plan and 2001 Non-Officer Stock Option Plan, dated March 13, 2008 is incorporated herein by reference to Exhibit 10.12A of the Company's Form 10-K for the year ended December 31, 2007.
10.11	The AES Corporation 2003 Long Term Compensation Plan, as Amended and Restated, dated April 23, 2015, is incorporated herein by reference to Exhibit 99.1 of the Company's Form 8-K filed on April 23, 2015.
10.12	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.
10.13	Form of AES Performance Stock Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.13 of the Company's Form 10-K for the year ended December 31, 2015.
10.14	Form of AES Restricted Stock Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.14 of the Company's Form 10-K for the year ended December 31, 2015.
10.15	Form of AES Performance Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.15 of the Company's Form 10-K for the year ended December 31, 2015.
10.16	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.
10.17	Form of AES Performance Cash Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.17 of the Company's Form 10-K for the year ended December 31, 2015.
10.18	The AES Corporation Restoration Supplemental Retirement Plan, as amended and restated, dated December 29, 2008 is incorporated herein by reference to Exhibit 10.15 of the Company's Form 10-K for the year ended December 31, 2008.
10.18A	Amendment to The AES Corporation Restoration Supplemental Retirement Plan, dated December 9, 2011 is incorporated herein by reference to Exhibit 10.17A of the Company's Form 10-K for the year ended December 31, 2012.
10.19	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.
10.19A	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.
10.20	The AES Corporation Severance Plan, as amended and restated on August 4, 2017 is incorporated herein by reference to Exhibit 10.1 of the Company's Form 10-Q for the quarter ended June 30, 2017.
10.21	The AES Corporation Amended and Restated Executive Severance Plan dated August 4, 2017 is incorporated herein by reference to Exhibit 10.2 of the Company's Form 10-Q for the period ended June 30, 2017.
10.22	The AES Corporation Performance Incentive Plan, as Amended and Restated on April 23, 2015 is incorporated herein by reference to Exhibit 99.2 of the Company's Form 8-K filed on April 23, 2015.
10.23	The AES Corporation Deferred Compensation Program For Directors dated February 17, 2012 is incorporated herein by reference to Exhibit 10.22 of the Company's Form 10-K filed on December 31, 2011.
10.24	The AES Corporation Employment Agreement with Andrés Gluski is incorporated herein by reference to Exhibit 99.3 of the Company's Form 8-K filed on December 31, 2008.
10.25	Mutual Agreement, between Andrés Gluski and The AES Corporation dated October 7, 2011 is incorporated herein by reference to Exhibit 10.2 of the Company's Form 10-Q for the period ended September 30, 2011.
10.26	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.
10.27	Amendment No. 3, dated as of July 26, 2013 to the Fifth Amended and Restated Credit and Reimbursement Agreement, dated as of July 29, 2010 is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on July 29, 2013.
10.27A	Sixth Amended and Restated Credit and Reimbursement Agreement dated as of July 26, 2013 among The AES Corporation, a Delaware corporation, the Banks listed on the signature pages thereof, Citibank, N.A., as Administrative Agent and Collateral Agent, Citigroup Global Markets Inc., as Lead Arranger and Book Runner, Banc of America Securities LLC, as Lead Arranger and Book Runner and Co-Syndication Agent, Barclays Capital, as Lead Arranger and Book Runner and Co-Syndication Agent, RBS Securities Inc., as Lead Arranger and Book Runner and Co-Syndication Agent and Union Bank, N.A., as Lead Arranger and Book Runner and Co-Syndication Agent is incorporated herein by reference to Exhibit 10.1.A of the Company's Form 8-K filed on July 29, 2013.
10.27B	Appendices and Exhibits to the Sixth Amended and Restated Credit and Reimbursement Agreement, dated as of July 29, 2013 is incorporated herein by reference to Exhibit 10.1.B of the Company's Form 8-K filed on July 29, 2013.
10.27C	Amendment No. 1, dated as of May 6, 2016 to the Sixth Amended and Restated Credit and Reimbursement Agreement, dated as of July 23, 2013 among The AES Corporation, a Delaware corporation, the Banks listed on the signature pages thereof and Citibank, N.A. as Administrative Agent and Collateral Agent is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on May 9, 2016.
10.27D	Amendment No. 2, dated as of June 28, 2017, to the Sixth Amended and Restated Credit and Reimbursement Agreement, dated as of July 26, 2013 among The AES Corporation, a Delaware corporation, the Banks listed on the signature pages thereof and Citibank, N.A. as Administrative Agent and Collateral Agent is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on June 29, 2017.
10.27E	Annex A. to Amendment No. 2, dated as of June 28, 2017, to the Sixth Amended and Restated Credit and Reimbursement Agreement, dated as of July 26, 2013 is incorporated herein by reference to 10.1.A of the Company's Form 8-K filed on June 29, 2017.
10.28	Collateral Trust Agreement dated as of December 12, 2002 among The AES Corporation, AES International Holdings II, Ltd., Wilmington Trust Company, as corporate trustee and Bruce L. Bisson, an individual trustee is incorporated herein by reference to Exhibit 4.2 of the Company's Form 8-K filed on December 17, 2002 (SEC File No. 001-12291).
10.29	Security Agreement dated as of December 12, 2002 made by The AES Corporation to Wilmington Trust Company, as corporate trustee and Bruce L. Bisson, as individual trustee is incorporated herein by reference to Exhibit 4.3 of the Company's Form 8-K filed on December 17, 2002 (SEC File No. 001-12291).
10.30	Credit Agreement dated as of May 24, 2017 among The AES Corporation, as borrower, the bank listed therein and Bank of America, N.A., as administrative agent is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on May 24, 2017.

10.31	Charge Over Shares dated as of December 12, 2002 between AES International Holdings II, Ltd. and Wilmington Trust Company, as corporate trustee and Bruce L. Bisson, as individual trustee is incorporated herein by reference to Exhibit 4.4 of the Company's Form 8-K filed on December 17, 2002 (SEC File No. 001-12291).
10.32	Agreement and Plan of Merger, dated as of February 19, 2017, by and among AES Lumos Holdings, LLC, PIP5 Lumos LLC, AES Lumos Merger Sub, LLC, PIP5 Lumos MS LLC, FTP Power LLC and Fir Tree Solar LLC is incorporated herein by reference to Exhibit 10.31 of the Company's Form 10-K for the year ending December 31, 2016.
10.33	Consulting Agreement by and between The AES Corporation and Brian A. Miller dated February 26, 2018 (filed herewith)
12	Statement of computation of ratio of earnings to fixed charges (filed herewith).
21.1	Subsidiaries of The AES Corporation (filed herewith).
23.1	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP (filed herewith).
24	Powers of Attorney (filed herewith).
31.1	Rule 13a-14(a)/15d-14(a) Certification of Andrés Gluski (filed herewith).
31.2	Rule 13a-14(a)/15d-14(a) Certification of Thomas M. O'Flynn (filed herewith).
32.1	Section 1350 Certification of Andrés Gluski (filed herewith).
32.2	Section 1350 Certification of Thomas M. O'Flynn (filed herewith).
101.INS	XBRL Instance Document (filed herewith).
101.SCH	XBRL Taxonomy Extension Schema Document (filed herewith).
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document (filed herewith).
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document (filed herewith).
101.LAB	XBRL Taxonomy Extension Label Linkbase Document (filed herewith).
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document (filed herewith).

(c) Schedules

Schedule I—Financial Information of Registrant

SIGNATURES

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

THE AES CORPORATION
(Company)

Date: February 26, 2018

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

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

Name	Title	Date
* **Andrés Gluski**	President, Chief Executive Officer (Principal Executive Officer) and Director	February 26, 2018
* **Charles L. Harrington**	Director	February 26, 2018
* **Kristina M. Johnson**	Director	February 26, 2018
* **Tarun Khanna**	Director	February 26, 2018
* **Holly K. Koeppel**	Director	February 26, 2018
* **James H. Miller**	Director	February 26, 2018
* **Alain Monié**	Director	February 26, 2018
* **John B. Morse**	Director	February 26, 2018
* **Moises Naim**	Director	February 26, 2018
* **Charles O. Rossotti**	Chairman of the Board and Lead Independent Director	February 26, 2018
* **Jeffrey W. Ubben**	Director	February 26, 2018
/s/ THOMAS M. O'FLYNN **Thomas M. O'Flynn**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2018
/s/ SARAH R. BLAKE **Sarah R. Blake**	Vice President and Controller (Principal Accounting Officer)	February 26, 2018

*By: /s/ PAUL L. FREEDMAN
Attorney-in-fact

February 26, 2018

THE AES CORPORATION AND SUBSIDIARIES

INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedule I—Condensed Financial Information of Registrant S-2

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, 2017	December 31, 2016
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 10	$ 109
Restricted cash	—	3
Accounts and notes receivable from subsidiaries	143	155
Prepaid expenses and other current assets	27	39
Total current assets	180	306
Investment in and advances to subsidiaries and affiliates	8,239	7,561
Office Equipment:		
Cost	27	26
Accumulated depreciation	(18)	(16)
Office equipment, net	9	10
Other Assets:		
Other intangible assets, net of accumulated amortization	3	5
Deferred financing costs, net of accumulated amortization of $2 and $1, respectively	5	5
Deferred income taxes	289	1,041
Other assets	2	13
Total other assets	299	1,064
Total assets	$ 8,727	$ 8,941
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 18	$ 18
Accounts and notes payable to subsidiaries	381	304
Accrued and other liabilities	246	250
Senior notes payable—current portion	5	—
Total current liabilities	650	572
Long-term Liabilities:		
Senior notes payable	4,625	4,154
Junior subordinated notes and debentures payable	—	517
Accounts and notes payable to subsidiaries	967	883
Other long-term liabilities	20	21
Total long-term liabilities	5,612	5,575
Stockholders' equity:		
Common stock	8	8
Additional paid-in capital	8,501	8,592
Accumulated deficit	(2,276)	(1,146)
Accumulated other comprehensive loss	(1,876)	(2,756)
Treasury stock	(1,892)	(1,904)
Total stockholders' equity	2,465	2,794
Total liabilities and equity	$ 8,727	$ 8,941

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF OPERATIONS

For the Years Ended December 31,	**2017**	**2016**	**2015**
		(in millions)	
Revenue from subsidiaries and affiliates	$ 28	$ 14	$ 24
Equity in earnings of subsidiaries and affiliates	630	(615)	859
Interest income	49	19	24
General and administrative expenses	(158)	(144)	(154)
Other income	5	7	24
Other expense	(554)	(65)	(6)
Loss on extinguishment of debt	(92)	(14)	(105)
Interest expense	(317)	(344)	(364)
Income (loss) before income taxes	(409)	(1,142)	302
Income tax benefit (expense)	(752)	12	4
Net income (loss)	$ (1,161)	$ (1,130)	$ 306

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF COMPREHENSIVE LOSS

YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015

	2017	2016	2015
		(in millions)	
NET INCOME (LOSS)	$ (1,161)	$ (1,130)	$ 306
Foreign currency translation activity:			
Foreign currency translation adjustments, net of income tax benefit (expense) of $11, $1 and $1, respectively	18	117	(674)
Reclassification to earnings, net of $0 income tax for all periods	643	992	—
Total foreign currency translation adjustments, net of tax	661	1,109	(674)
Derivative activity:			
Change in derivative fair value, net of income tax benefit (expense) of $13, $(5) and $4, respectively	(14)	2	(5)
Reclassification to earnings, net of income tax benefit (expense) of $1, $1 and $(12), respectively	37	28	48
Total change in fair value of derivatives, net of tax	23	30	43
Pension activity:			
Prior service cost for the period, net of income tax expense of $1, $5 and $0, respectively	1	9	1
Change in pension adjustments due to net actuarial gain (loss) for the period, net of income tax benefit (expense) of $6, $10 and $(7), respectively	(20)	(22)	18
Reclassification of earnings due to amortization of net actuarial loss, net of income tax benefit (expense) of $(126), $2 and $(2), respectively	248	1	2
Total change in unfunded pension obligation	229	(12)	21
OTHER COMPREHENSIVE INCOME (LOSS)	913	1,127	(610)
COMPREHENSIVE LOSS	$ (248)	$ (3)	$ (304)

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2017	2016	2015
		(in millions)	
Net cash provided by operating activities	$ 148	$ 818	$ 475
Investing Activities:			
Investment in and net advances to subsidiaries	(339)	(650)	(221)
Return of capital	243	247	501
Decrease in restricted cash	3	29	49
Additions to property, plant and equipment	(13)	(12)	(11)
Net cash provided by (used in) investing activities	(106)	(386)	318
Financing Activities:			
Borrowings under the revolver, net	207	—	—
Borrowings of notes payable and other coupon bearing securities	1,025	500	575
Repayments of notes payable and other coupon bearing securities	(1,353)	(808)	(915)
Loans from subsidiaries	309	183	—
Purchase of treasury stock	—	(79)	(482)
Proceeds from issuance of common stock	1	1	4
Common stock dividends paid	(317)	(290)	(276)
Payments for deferred financing costs	(12)	(12)	(6)
Distributions to noncontrolling interests	—	(2)	—
Other financing	(7)	(3)	(18)
Net cash used in financing activities	(147)	(510)	(1,118)
Effect of exchange rate changes on cash	6	1	—
Decrease in cash and cash equivalents	(99)	(77)	(325)
Cash and cash equivalents, beginning	109	186	511
Cash and cash equivalents, ending	$ 10	$ 109	$ 186
Supplemental Disclosures:			
Cash payments for interest, net of amounts capitalized	$ 282	$ 296	$ 314
Cash payments for income taxes, net of refunds	$ 2	$ 6	$ —

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 as well as effects of U.S. tax law reform enacted in 2017.

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 Secured Notes and Loans Payable ($ in millions)

	Interest Rate	Maturity	December 31, 2017	December 31, 2016
Senior Unsecured Note	LIBOR + 3.00%	2019	$ —	$ 240
Senior Unsecured Note	8.00%	2020	228	469
Senior Unsecured Note	7.38%	2021	690	966
Drawings on secured credit facility	LIBOR + 2.00%	2021	207	—
Senior Secured Term Loan	LIBOR + 2.00%	2022	521	—
Senior Unsecured Note	4.88%	2023	713	713
Senior Unsecured Note	5.50%	2024	738	738
Senior Unsecured Note	5.50%	2025	573	573
Senior Unsecured Note	6.00%	2026	500	500
Senior Unsecured Note	5.13%	2027	500	—
Unamortized (discounts)/premiums & debt issuance (costs)			(40)	(45)
Subtotal			$ 4,630	$ 4,154
Less: Current maturities			(5)	—
Total			$ 4,625	$ 4,154

Junior Subordinated Notes Payable ($ in millions)

	Interest Rate	Maturity	December 31, 2017	December 31, 2016
Term Convertible Trust Securities	6.75%	2029	$ —	$ 517

FUTURE MATURITIES OF RECOURSE DEBT — As of December 31, 2017 scheduled maturities are presented in the following table (in millions):

December 31,	Annual Maturities
2018	$ 5
2019	5
2020	234
2021	902
2022	500
Thereafter	3,024
Unamortized (discount)/premium & debt issuance (costs)	(40)
Total debt	$ 4,630

3. Dividends from Subsidiaries and Affiliates

Cash dividends received from consolidated subsidiaries were $1.2 billion, $1 billion, and $748 million for the years ended December 31, 2017, 2016, and 2015, respectively. There were no cash dividends received from affiliates accounted for by the equity method for the years ended December 31, 2017, 2016, and 2015.

4. Guarantees and Letters of Credit

GUARANTEES — In connection with certain of its project financing, acquisition, and power purchase agreements, the Parent Company has expressly undertaken limited obligations and commitments, most of which will only be effective or will be terminated upon the occurrence of future events. These obligations and commitments, excluding those collateralized by letter of credit and other obligations discussed below, were limited as of December 31, 2017, by the terms of the agreements, to an aggregate of approximately $842 million representing 22 agreements with individual exposures ranging from $1 million to $272 million. These amounts exclude normal and customary representations and warranties in agreements for the sale of assets (including ownership in associated legal entities) where the associated risk is considered to be nominal.

LETTERS OF CREDIT — At December 31, 2017, the Parent Company had $36 million in letters of credit outstanding under the senior secured credit facility, representing 21 agreements with individual exposures up to $13 million, and $52 million in letters of credit outstanding under the senior unsecured credit facility, representing 4 agreements with individual exposures ranging from $2 million to $26 million. During 2017, the Parent Company paid letter of credit fees ranging from 0.25% to 2.25% per annum on the outstanding amounts.