AES CORP
Form 10-K
February 24, 2016

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

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2015
-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
AES Trust III, $3.375 Trust Convertible Preferred Securities	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 x No o
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 o No x
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 x No o
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 x No o
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. x
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller	Smaller reporting company o

reporting company)

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates on June 30, 2015, the last business day of the Registrant's most recently completed second fiscal quarter (based on the adjusted closing sale price of $12.88 of the Registrant's Common Stock, as reported by the New York Stock Exchange on such date) was approximately $8.79 billion.

The number of shares outstanding of Registrant's Common Stock, par value $0.01 per share, on February 18, 2016 was 659,733,335

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Registrant's Proxy Statement for its 2016 annual meeting of stockholders are incorporated by reference in Parts II and III

THE AES CORPORATION FISCAL YEAR 2015 FORM 10-K

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GLOSSARY OF TERMS

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

Adjusted EPS	Adjusted Earnings Per Share, a non-GAAP measure
Adjusted PTC	Adjusted Pretax Contribution, a non-GAAP measure of operating performance
AES	The Parent Company and its subsidiaries and affiliates
AFUDC	Allowance for Funds Used During Construction
ANEEL	Brazilian National Electric Energy Agency
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
BNDES	Brazilian Development Bank
BOT	Build, Operate and Transfer
BOT Company	AES-VCM Mong Duong Power Company Limited
BTA	Best Technology Available
CAA	United States Clean Air Act
CAMMESA	Wholesale Electric Market Administrator in Argentina
CCGT	Combined Cycle Gas Turbine
CDEC	Economic Load Dispatch Center
CDI	Brazilian equivalent to LIBOR
CDPQ	La Caisse de depot et placement du Quebec
CDEEE	Dominican Corporation of State Electrical Companies
CEO	Chief Executive Officer
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980 (also known as "Superfund")
CESCO	Central Electricity Supply Company of Orissa Ltd.
CFB	Circulating Fluidized Bed Boiler
CFE	Federal Commission of Electricity
CND	National Dispatch Center
CNE	National Energy Commission
COD	Commercial Operation Date
COFINS	Contribuição para o Financiamento da Seguridade Social
CO_2	Carbon Dioxide
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CP	Capacity Performance
CPCN	Certificate of Public Convenience and Necessity
CPI	United States Consumer Price Index
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.
DPLE	DPL Energy, LLC, a wholly-owned subsidiary of DPL (renamed AES Ohio Generation, LLC effective 2/1/2016)
DPLER	DPL Energy Resources, Inc.

DPP	Dominican Power Partners
EBITDA	Earnings before Interest, Taxes, Depreciation & Amortization
ECCRA	Environmental Compliance Cost Recovery Adjustment
EGCO Group	Electricity Generating Public Company Limited
ELV	Emission Limit Values
EMIR	European Market Infrastructure Regulation
EOOD	Single person private limited liability company in Bulgaria
EPA	United States Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EPIRA	Electric Power Industry Reform Act of 2001
ERC	Energy Regulatory Commission
ESO	Electricity System Operator
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
EWG	Exempt Wholesale Generators
FAC	Fuel Adjustment Charges
FASB	Financial Accounting Standards Board
FCA	Federal Court of Appeals
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
G&A	General and Administrative
GAAP	Generally Accepted Accounting Principles in the United States
GEL	General Electricity Law
GHG	Greenhouse Gas
GNPIPD	Gross National Product - Implicit Price Deflator
GSA	Gas Supply Agreement
GWh	Gigawatt Hours
HLBV	Hypothetical Liquidation Book Value
HTA	Heads of Terms Agreement
ICC	International Chamber of Commerce
ICM	Industrial and Commerce Ministry
IDEM	Indiana Department of Environmental Management
IED	Industrial Emission Directive
IFC	International Finance Corporation
IOA	Investment Obligation Agreement
IPALCO	IPALCO Enterprises, Inc.
IPL	Indiana, Indianapolis Power & Light Company
IPP	Independent Power Producers
IRT	Annual Tariff Adjustment in Brazil
ISO	Independent System Operator
IURC	Indiana Utility Regulatory Commission
KPI	Key Performance Indicator
kWh	Kilowatt Hours
LIBOR	London Inter Bank Offered Rate
LNG	Liquefied Natural Gas
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator, Inc.
MME	Ministry of Mines and Energy
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)
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined Cycle
NOV	Notice of Violation
NO_X	Nitrogen Dioxide

NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NSR	New Source Review
NYISO	New York Independent System Operator, Inc.
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
PCB	Polychlorinated biphenyl
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
PRP	Potentially Responsible Parties
PSU	Performance Stock Unit
PUCO	The Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
RCOA	Retail Competition & Open Access
RGGI	Regional Greenhouse Gas Initiative
RMRR	Routine Maintenance, Repair and Replacement
ROE	Return on Equity
RPM	Reliability Pricing Model
RSU	Restricted Stock Unit
RTO	Regional Transmission Organization
SADI	Argentine Interconnected System
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SBU	Strategic Business Unit
SCE	Southern California Edison
SEC	United States Securities and Exchange Commission
SEM	Single Electricity Market
SEN	National Power System
SEWRC	Bulgaria's State Energy and Water Regulatory Commission
SIC	Central Interconnected Electricity System
SIE	Superintendence of Electricity
SIN	National Interconnected System
SING	Northern Interconnected Electricity System
SIP	State Implementation Plan
SNE	National Secretary of Energy
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool Electric Energy Network
SSO	Standard Service Offer
SSR	Service Stability Rider
TA	Transportation Agreement
TECONS	Term Convertible Preferred Securities
TIPRA	Tax Increase Prevention and Reconciliation Act of 2005
TNP	Transitional National Plan
TSR	Total Shareholder Return
UPME	Mining and Energetic Planning Unit
U.S.	United States
VAT	Value Added Tax
VIE	Variable Interest Entity
Vinacomin	Vietnam National Coal-Mineral Industries Holding Corporation Ltd.
WACC	Weighted Average Cost of Capital
WECC	Western Electric Coordinating Council
WESM	Wholesale Electricity Spot Market

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, as well as GHG emissions reduction 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 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
- 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

Overview

We were incorporated in 1981 and are a diversified power generation and utility company organized into six market-oriented SBUs: US (United States), Andes (Chile, Colombia, and Argentina), Brazil, MCAC (Mexico, Central America and Caribbean), Europe, and Asia.

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.

Business Lines & SBUs — Within our six SBUs mentioned above, 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. For each SBU, the following table summarizes our generation and utility businesses by capacity, number of facilities, utility customers and utility GWh sold.

SBU	Business Line	Generation Capacity (Gross MW)	Generation Facilities	Utility Customers	Utility GWh	Utility Businesses
US —	Generation	5,604	18			
	Utilities	6,524	16	1.0 million	34,797	2
Andes —	Generation	8,141	33			
Brazil —	Generation	3,298	13			

	Utilities			8.2 million	56,861	2
MCAC —	Generation	3,239	16			
	Utilities			1.3 million	3,754	4
Europe —	Generation	6,781	12			
Asia —	Generation	2,290	3			
		35,876 [(1)]	111	10.5 million	95,412	8

(1) 26,912 proportional MW. Proportional MW is equal to gross MW of a generation facility multiplied by AES' equity ownership percentage in such facility.

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Strategy

In September 2011, we implemented a new strategy to maximize value for our shareholders and over the last four years we have made significant progress towards our goals by executing on the following pillars:

- Reducing Complexity. By exiting businesses and markets where we do not have a competitive advantage, we have simplified our portfolio and reduced risk. Over the past four years, we have sold assets to generate $3.4 billion in equity proceeds for AES, decreasing the total number of countries where we have operations from 28 to 17. We exited Sri Lanka early in 2016, by selling our generation business, Kelanitissa, for $18 million. We exited several of these markets, including Ukraine, Turkey and Africa, at opportune times, as risks for these businesses have increased since the sales, which we believe would have adversely impacted the valuations of such businesses. In 2015, we announced or closed $787 million in asset sales proceeds.
- Leveraging Our Platforms. We are focusing our growth on platform expansions in markets where we already operate and have a competitive advantage to realize attractive risk-adjusted returns. We currently have 5,620 MW under construction. These projects represent $7 billion in total capital expenditures, with 85% of AES' $1.2 billion in equity already funded, and we expect the majority of these projects to come on-line through 2018. In 2015, we brought on-line five projects for a total of 1,484 MW. This capacity includes the 1,240 MW coal-fired Mong Duong 2 facility in Vietnam, which we completed six months early and under budget.
- Performance Excellence. We strive to be a low-cost manager of a portfolio of international energy assets and to derive synergies and scale from our businesses. In 2011, we set a goal to reduce our G&A expenses by $200 million by 2015, and in 2014, we achieved these reductions one year early. We recently launched a $150 million cost reduction and revenue enhancement initiative. This initiative will include overhead reductions, procurement efficiencies and operational improvements. We expect to achieve at least $50 million in savings in 2016, ramping up to $150 million, including modest revenue enhancements, in 2018.
- Expanding Access to Capital. We have raised $2.5 billion in proceeds to AES by building strategic partnerships at the project and business level. Through these partnerships, we aim to optimize our risk-adjusted returns in our existing businesses and growth projects. By selling down portions of certain businesses, we can adjust our global exposure to commodity, fuel, country and macroeconomic risks. Partial sell-downs of our assets can serve to highlight the value of businesses in our portfolio.
- Allocating Capital in a Disciplined Manner. Our top priority is to maximize risk-adjusted returns to our shareholders, which we achieve by investing our discretionary cash and recycling the capital we receive from asset sales and strategic partnerships. To that end, since September 2011 we have repurchased $1.5 billion of our shares and benefited from a low interest rate environment, by transacting on $24 billion in debt deals at the Parent and our subsidiaries. These debt transactions represent $14 billion in refinancing and $10 billion in new financing, and we extended the maturities on $3.4 billion in Parent debt.

Note: Investments in subsidiaries excludes $2.3 billion investment in DPL.

Most recently, we increased our quarterly dividend by 10% to $0.11 per share beginning in the first quarter of 2016. This dividend increase reflects our expectation that we will maintain 10% annual growth in our dividend.

Generation

We currently own and/or operate a generation portfolio of 29,352 MW, excluding the generation capabilities of our integrated utilities. 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, fixed-cost management, sourcing and competition.

Electricity Sales Contracts — Our generation businesses sell electricity under medium- or long-term contracts ("contract sales") or under short-term agreements in competitive markets ("short-term sales").

Contract Sales — Most of our generation fleet sells electricity under contracts. Our medium-term contract sales have a term of 2 to 5 years, while our long-term contracts have a term of more than 5 years. Across our portfolio, the average remaining contract term is 7 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 under the Fuel Costs section below). These contracts are intended to reduce exposure to the volatility of fuel prices 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 and 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, including debt and return on capital invested. Although our project debt may consist of both fixed and floating rate debt, we typically hedge a significant portion of our exposure to variable interest rates. For foreign exchange, we generally structure the revenue of the business to match the currency of the debt and fixed costs. 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 section 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 an average term of less than 2 years, including spot sales, directly in the short-term market, or, in some cases, 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.

In certain markets, such as Argentina and Kazakhstan, a 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.

Capacity Payments and Short-Term Sales — 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.

34% 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.

33% 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.

28% of our generation plants are fueled by renewables, including hydro, wind and energy storage, which do not have significant fuel costs.

5% of our generation fleet utilizes oil, diesel and petroleum coke ("pet coke") 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.

Renewable Generation Facilities — We currently own and operate 8,145 MW (4,237 proportional MW) of renewable generation, including hydro, wind, energy storage, solar, biomass and landfill gas.

Seasonality, Weather Variations and Economic Activity — Our generation businesses are affected by seasonal weather patterns throughout the year and, therefore, operating margin is not generated evenly by month during 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. See Item 7.—Management's Discussion and Analysis—Key Trends and Uncertainties of this Form 10-K for further details of the impact of dry hydrological conditions. 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 operating and maintenance 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' eight utility businesses distribute power to 10.5 million people in three countries. AES' two utilities in the U.S. also include generation capacity totaling 6,524 MW. The utility businesses have a variety of structures, ranging from integrated utility to pure transmission and distribution businesses.

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.

Regulated Rate of Return and Tariff — In exchange for the exclusive right to sell or distribute electricity in a franchise area, our utility businesses are subject to government regulation. This regulation sets the prices ("tariffs") that our utilities are allowed to charge retail 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 a certain usage level and may include a pass-through to the customer 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. In addition to fuel and purchased energy, other types of costs may be passed through to customers via an existing mechanism, such as certain environmental expenditures that are covered under an environmental tracker at our utility in Indiana, IPL. 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 a wheeling and other 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 throughout the year and, therefore, the operating revenues and associated operating expenses are not generated evenly by month during 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. The retail kWh 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 specific with incentives or penalties for performance against these standards. In other cases, the standards are implicit and the utility must operate to meet customer expectations.

Competition — Our integrated utilities, such as IPL and DP&L, operate as the sole distributor of electricity within their respective jurisdictions. Our businesses own and operate all of the businesses and facilities necessary to generate, transmit and distribute electricity. Competition in the regulated electric business is primarily from the on-site generation for industrial customers; however, in Ohio, customers in our service territory have the ability to switch to alternative suppliers for their generation service. Our integrated utilities, particularly DP&L, are 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 pure transmission and distribution businesses, such as those in Brazil and 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 businesses, new plants may be built in response to customer needs or to comply with regulatory developments and 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. For construction, 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.

Environmental Matters

We are subject to various international, federal, state, and local regulations in all of our markets. These regulations 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.

We are also subject to various federal, state, regional and local environmental protection and health and safety laws and regulations governing, among other things, the generation, storage, handling, use, disposal and transportation of hazardous materials; the emission and discharge of hazardous and other materials into the environment; and the health and safety of our employees. These laws and regulations often require a lengthy and complex process of obtaining and renewing permits and other governmental authorizations from federal, state and local agencies. Violation of these laws, regulations or permits can result in substantial fines, other sanctions, suspension or revocation of permits and/or facility shutdowns. See later in Item 1.—Business—Environmental and Land-Use Regulations for further regulatory and environmental discussion.

SBUs
All SBUs include generation facilities and three include utility businesses. The Company measures the operating performance of its SBUs using Adjusted PTC and Proportional Free Cash Flow, both of which are non-GAAP measures (see definitions below).
AES' primary sources of Revenue, Operating Margin, Adjusted PTC and Proportional Free Cash Flow are from generation and utility businesses. The Adjusted PTC and Proportional Free Cash Flow by SBU for the year ended December 31, 2015 are shown below. The percentages for Adjusted PTC are the contribution by each SBU to the gross metric, i.e., the total Adjusted PTC by SBU, before deductions for Corporate. See Item 8.—Financial Statements and Supplementary Data of this Form 10-K for reconciliation.
In 2015, approximately 80% of Adjusted PTC and Proportional Free Cash Flow was contributed by our businesses in the Americas — including the US, Andes, Brazil and MCAC SBUs.
We define Adjusted PTC as pretax income from continuing operations attributable to AES excluding gains or losses due to (a) unrealized gains or losses related to derivative transactions, (b) unrealized foreign currency gains or losses, (c) gains or losses due to dispositions and acquisitions of business interests, (d) losses due to impairments, and (e) costs due to the early retirement of debt. Adjusted PTC in each SBU includes the effect of intercompany transactions with other SBUs other than interest and charges for certain management services.
We define Proportional Free Cash Flow as cash flows from operating activities excluding capital expenditures related to service concession assets, less maintenance and non-recoverable environmental capital costs, adjusted for the estimated impact of noncontrolling interests. Proportional Free Cash Flow in each SBU includes the effect of intercompany transactions with other SBUs except for interest, tax sharing, charges for management fees and transfer pricing.
Our Organization and Segments
The segment reporting structure uses the Company's management reporting structure as its foundation to reflect how the Company manages the business internally and is organized by geographic regions which provide better socio-political-economic understanding of our business. The management reporting structure is organized along six SBUs — US, Andes, Brazil, MCAC, Europe, and Asia — which are led by our SBU Presidents.
Corporate and Other — For financial reporting purposes, the Company's corporate activities are reported within "Corporate and Other" because they do not require separate disclosure under segment reporting accounting guidance. "Corporate and Other" also includes costs related to corporate overhead which are not directly associated with the operations of our six reportable segments and other intercompany charges such as self-insurance premiums which are fully eliminated in consolidation. See Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 17—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 (including information on revenue from external customers, Adjusted PTC—a non-GAAP measure, Proportional Free Cash Flow—a non-GAAP measure, and total assets by segment) used for financial reporting purposes.
The following describes our businesses within our six SBUs:
US SBU
Our US SBU has 18 generation facilities and two integrated utilities in the United States. Our U.S. operations accounted for the following proportions of consolidated AES Operating Margin, AES Adjusted PTC (a non-GAAP measure), AES Operating Cash Flow, and AES Proportional Free Cash Flow (a non-GAAP measure):

US SBU [1]	2015		2014		2013	
% of AES Operating Margin	22	%	23	%	21	%
% of AES Adjusted PTC (a non-GAAP measure)	23	%	24	%	24	%
% of AES Operating Cash Flow	34	%	37	%	28	%
% of AES Proportional Free Cash Flow (a non-GAAP measure)	36	%	46	%	37	%

[1] Percentages reflect the contributions by our US SBU before deductions for Corporate.
The following table provides highlights of our US operations:

Generation Capacity	12,128 gross MW (11,260 proportional MW)

Generation Facilities	19 (1 under construction)
Key Generation Businesses	Southland, Hawaii and US Wind
Utilities Penetration	1,002,000 customers (31,112 GWh)
Utility Businesses	2 integrated utilities (includes 18 generation plants, 4 under construction)
Key Utility Businesses	IPL and DPL

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Operating installed capacity of our US SBU totals 12,128 MW. IPL's parent, IPALCO Enterprises, Inc., and DPL Inc. are voluntary SEC registrants, and as such, follow public filing requirements of the Securities Exchange Act of 1934. Presented in the table below is a list of our U.S. generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Ownership (% Rounded)		Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Southland—Alamitos	U.S.-CA	Gas	2,075	100	%	1998	2018	Southern California Edison
Southland—Redondo Beach	U.S.-CA	Gas	1,392	100	%	1998	2018	Southern California Edison
Southland—Huntington Beach	U.S.-CA	Gas	474	100	%	1998	2018	Southern California Edison
Shady Point	U.S.-OK	Coal	360	100	%	1991	2018	Oklahoma Gas & Electric
Buffalo Gap II[(1),(2)]	U.S.-TX	Wind	233	100	%	2007	2017	Direct Energy
Hawaii	U.S.-HI	Coal	206	100	%	1992	2022	Hawaiian Electric Co.
Warrior Run	U.S.-MD	Coal	205	100	%	2000	2030	First Energy
Buffalo Gap III[(1)]	U.S.-TX	Wind	170	100	%	2008		
Buffalo Gap I[(1)]	U.S.-TX	Wind	121	100	%	2006	2021	Direct Energy
Laurel Mountain	U.S.-WV	Wind	98	100	%	2011		
Mountain View I & II[(1)]	U.S.-CA	Wind	67	100	%	2008	2021	Southern California Edison
Distributed PV - Commercial[(3)]	U.S.-Various	Solar	56	80%-97%		2009-2015	2029-2041	Utility, Municipality, Education, Non-Profit
Mountain View IV	U.S.-CA	Wind	49	100	%	2012	2032	Southern California Edison
Tehachapi	U.S.-CA	Wind	35	100	%	2006	2016	Southern California Edison
Laurel Mountain ES	U.S.-WV	Energy Storage	32	100	%	2011		
Tait ES	U.S.-OH	Energy Storage	20	100	%	2013		
Distributed PV - Residential[(3)]	U.S.-Various	Solar	9	95	%	2012-2015	2037-2040	Residential
Advancion Applications Center	U.S.-PA	Energy Storage	2	100	%	2013		
			5,604					

(1) 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.

(2) Power Purchase Agreement with Direct Energy is for 80% of annual expected energy output.

(3) AES operates these facilities located throughout the U.S. through management or O&M agreements as of 12/31/15.

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

Business	Location	Fuel	Gross MW	AES Equity Interest (% Rounded)		Expected Date of Commercial Operations
IPL MATS [1]	U.S.-IN	Coal	1,713	75	%	1H 2016
Eagle Valley CCGT [1]	U.S.-IN	Gas	671	75	%	1H 2017
Harding Street Units 5-7 [1]	U.S.-IN	Gas	630	75	%	1H 2016
Harding Street ES [1]	U.S.-IN	Energy Storage	20	75	%	1H 2016
Warrior Run ES	U.S.-MD	Energy Storage	10	100	%	1H 2016
US Total			3,044			

(1) In the first quarter of 2015, La Caisse de depot et placement du Quebec ("CDPQ") invested $247 million for a 15% interest in AES US Investments, Inc. (AES US Investments), a subsidiary of AES that owns IPALCO Enterprises, Inc. ("IPALCO"). In the second quarter of 2015, CDPQ invested an additional $214 million and we expect CDPQ to invest an additional $134 million in IPALCO by 2016. After completion of this investment, CDPQ's direct and indirect interests in IPALCO will total 30%, AES will own 85% of AES US Investments, and AES US Investments will own 82.35% of IPALCO.

Presented below are our U.S. utilities and their generation facilities:

Business	Location	Approximate Number of Customers Served as of 12/31/2015	GWh Sold in 2015	Fuel	Gross MW	AES Equity Interest (% Rounded)		Year Acquired or Began Operation
DPL[1]	U.S.-OH	517,000	16,714	Coal/Gas/Oil	3,066	100	%	2011
IPL[2]	U.S.-IN	485,000	14,398	Coal/Gas/Oil	3,458	75	%	2001
		1,002,000	31,112		6,524			

(1) DPL subsidiary DP&L has the following plants: Tait Units 1-3 and diesels, Yankee Street, Yankee Solar, Monument and Sidney. DP&L jointly owned plants: Conesville Unit 4, Killen, Miami Fort Units 7 & 8, Stuart and Zimmer. In addition to the above, DP&L also owns a 4.9% equity ownership in OVEC ("Ohio Valley Electric Corporation"), 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 capacity is approximately 103 MW. DPL Energy, LLC plants: Tait Units 4-7 and Montpelier Units 1-4.

(2) In the first quarter of 2015, CDPQ invested $247 million for a 15% interest in AES US Investments, Inc. (AES US Investments), a subsidiary of AES that owns IPALCO. In the second quarter of 2015, CDPQ invested an additional $214 million and we expect CDPQ to invest an additional $134 million in IPALCO by 2016. After completion of this investment, CDPQ's direct and indirect interests in IPALCO will total 30%, AES will own 85% of AES US Investments, and AES US Investments will own 82.35% of IPALCO. IPL plants: Eagle Valley, Georgetown, Harding Street and Petersburg.

The following map illustrates the location of our U.S. facilities:
U.S. Businesses
U.S. Utilities
IPALCO
Business Description — IPALCO owns all of the outstanding common stock of IPL. IPL is engaged primarily in generating, transmitting, distributing and selling electric energy to approximately 485,000 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 934,000. IPL owns and operates four generating stations. Two of the generating stations are primarily coal-fired; however, one of these stations is in the process of being converted to natural gas and will be fully converted in 2016. The third station has a combination of units that use coal (baseload capacity), natural gas and/or oil (peaking capacity) for fuel to produce electricity. The fourth station is a small peaking station that uses gas-fired combustion turbine technology for the production of electricity. IPL's net electric generation capacity for winter is 3,233 MW and net summer capacity is 3,115 MW.
On December 15, 2014, the Company executed an agreement with CDPQ, a long-term institutional investor headquartered in Quebec, Canada. Pursuant to the agreement, CDPQ purchased 15% of AES US Investments, Inc. ("AES US Investments"), a wholly-owned subsidiary of AES that owns 100% of IPALCO, for $247 million. This transaction closed on February 11, 2015. In addition, in April 2015, IPALCO received an equity capital contribution of $214 million from the issuance of 11,818,828 shares of common stock to CDPQ for funding needs primarily related to IPL's environmental construction program, which IPALCO then made the same investment in IPL. After the April investment, CDPQ's direct and indirect ownership interests in IPALCO totaled 25%. CDPQ has committed to approximately $134 million of additional investments in IPALCO through 2016, which will be used primarily to help fund existing environmental and replacement generation projects at IPL. Upon completion of these transactions, CDPQ's direct and indirect interests in IPALCO will total 30%, AES will own 85% of AES US Investments, and AES US Investment will own 82.35% of IPALCO. There will be no change in management or operational control of AES US Investments or IPALCO as a result of these transactions.
Market Structure — IPL is one of many transmission system owner members in the MISO. MISO is a 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. IPL offers the available electricity production of each of its generation assets into the MISO day-ahead and real-time markets. MISO operates on a merit order dispatch, considering transmission constraints and other reliability issues to meet the total demand in the MISO region.
Regulatory Framework — Retail Ratemaking — In addition to the regulations referred to below in Other Regulatory Matters, IPL is subject to regulation by the IURC with respect to IPL's 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 both comprehensive and typical of the traditional form of regulation generally imposed by state public utility commissions. IPL's tariff rates for electric service to retail customers consist of basic rates and charges, which are set and approved by the IURC after public hearings. The IURC gives consideration to all allowable costs for ratemaking purposes including a fair return on the fair value of the utility property used and useful in providing service to customers. 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, referred to as the FAC, and (ii) a rider for the timely recovery of costs incurred to comply with environmental laws and regulations referred to as ECCRA. These components function somewhat independently of one another, but the overall structure of IPL's rates and charges would be subject to review at the time of any review of IPL's basic rates and charges. IPL's basic rates and charges were last adjusted in 1996; however, IPL filed a petition with the IURC on December 29, 2014 for authority to increase its basic rates and charges. IPL's proposed rate increase, filed as part of IPL's rebuttal testimony in this proceeding, is $63.3 million, or 5.2%. An order on this proceeding will likely be issued by the IURC early in 2016.
Environmental Matters — MATS — In April 2012, the EPA's rule to establish maximum achievable control technology standards for each hazardous air pollutant regulated under the CAA emitted from coal and oil-fired power plants, known as MATS, became effective. On August 14, 2013, the IURC approved IPL's MATS plan, which includes investing up to $511 million in the installation of new pollution control equipment on IPL's five largest baseload generating units. These coal-fired units are located at IPL's Petersburg and Harding Street generating stations. The IURC also approved IPL's request to recover operating and construction costs for this equipment, including a return, through a rate adjustment mechanism with certain stipulations. Funding for these capital expenditures is expected to be obtained from additional debt financing at IPL; equity contributions; borrowing capacity on IPL's committed credit facilities; and cash generated from operating activities.
Replacement Generation — IPL has several generating units that are expected to retire or refuel by 2017. These units are primarily coal-fired and represent 472 MW of net capacity in total. To replace this generation, IPL filed a petition and case-in-chief with the IURC in April 2013 seeking a CPCN to build a 550 to 725 MW CCGT at its Eagle Valley Station site in Indiana and to refuel Harding Street Station Units 5 and 6 from coal to natural gas (approximately 100 MW net capacity each). In May 2014, IPL received an order on the CPCN from the IURC authorizing the refueling project and granting approval to build a 644 to 685 MW CCGT at a total budget of $649 million. The current estimated cost of these projects is $632 million. IPL requested and 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 until such time that IPL is allowed to collect both a return and depreciation expense of the CCGT and refueling projects. The CCGT is expected to be placed into service in April 2017, and the refueling project is expected to be completed by early 2016. The costs to build and operate the CCGT and for 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 the assets have been placed in service. In October 2014, IPL filed a petition and case-in-chief with the IURC seeking a CPCN to refuel Harding Street Station Unit 7 from coal to natural gas (about 410 MW net capacity). On July 29, 2015 IPL received approval for this CPCN from the IURC. This conversion is part of IPL's overall wastewater compliance plan for its power plants and is expected to be completed in 2016 (as discussed in Environmental Wastewater Requirements below).
Environmental Wastewater Requirements — In August 2012, the IDEM issued NPDES permits to the IPL Petersburg, Harding Street, and Eagle Valley generating stations, which became effective in October 2012. In April 2013, IPL received an extension to the compliance deadline through September 2017 for IPL's Harding Street and Petersburg facilities through agreed orders with IDEM. IPL conducted studies to determine the operational changes and/or control equipment necessary to comply with the new limitations. On October 16, 2014, IPL filed its wastewater compliance plans with the IURC. On July 29, 2015, IPL received approval for a CPCN from the IURC to convert Unit 7 at the Harding Street Station from coal-fired to natural gas-fired, and also to install and operate wastewater treatment technologies at Harding Street Station and Petersburg Generation Station in southern Indiana. IPL plans to invest $326 million in these projects to help ensure compliance with the wastewater treatment requirements by 2017. Recovery of

these costs is expected through an Indiana statute which allows for 80% recovery of qualifying costs through a rate adjustment mechanism with the remainder recorded as a regulatory asset to be considered for recovery in the next basic rate case proceeding; however, there can be no assurances that IPL would be successful in that regard.

Key Financial Drivers — IPL's financial results are driven primarily by retail demand and rate base growth. Retail demand is influenced by local macroeconomic conditions. In addition, weather, energy efficiency and wholesale prices could also impact financial results. IPL's rate base growth is influenced by the timely recovery of capital expenditures, as well as passage of new legislation or implementation of 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. Please see above for a description of our major construction projects.

DPL Inc. ("DPL")
Business Description — DPL is an energy holding company whose principal subsidiaries include DP&L, DPLE, and DPLER.
DP&L generates, transmits, distributes and sells electricity to approximately 517,000 customers in a 6,000 square mile area of West Central Ohio. DP&L, solely or through jointly owned facilities, owns 2,510 MW of generation capacity and numerous transmission facilities.
DPLE owns peaking generation units representing 556 MW located in Ohio and Indiana.
DPLER, a competitive retail marketer, sells retail electricity to more than 124,000 retail customers in Ohio and Illinois. Approximately 110,000 of these customers are also distribution customers of DP&L in Ohio. On January 1, 2016, DPL closed on the sale of DPLER to Interstate Gas Supply, Inc. (IGS).
Market Structure — Since January 2001, electric customers within Ohio have been permitted to choose to purchase power under a contract with a CRES Provider or to continue to purchase power from their local utility under SSO rates established by the tariff. DP&L and other Ohio utilities continue to have the exclusive right to provide delivery service in their state certified territories, and DP&L had the obligation to supply retail generation service to customers that do not choose an alternative supplier. Beginning in 2014, a portion of the SSO generation supply is no longer supplied by DP&L but is provided by third parties through a competitive bid process. A total of 10% and 60% of the SSO load was sourced through competitive bid in 2014 and 2015, respectively, and 100% will be sourced in this manner beginning in 2016, respectively. The PUCO maintains jurisdiction over DP&L's delivery of electricity, SSO and other retail electric services. The PUCO has issued extensive rules on how and when a customer can switch generation suppliers, how the local utility will interact with CRES Providers and customers, including for billing and collection purposes, and which elements of a utility's rates are "bypassable" (i.e., avoided by a customer that elects a CRES Provider) and which elements are "non-bypassable" (i.e., charged to all customers receiving a distribution service irrespective of what entity provides the retail generation service).
PJM Operations — DP&L is a member of PJM. The PJM RTO 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 has an integrated planning process to identify potential needs for additional transmission to be built to avoid future reliability problems. 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, DP&L is also subject to charges and costs associated with PJM operations as approved by the FERC. Prior to 2015, the RPM was PJM's capacity construct. In 2015, PJM implemented a new Capacity Price ("CP") program, replacing the RPM model. The CP program offers the potential for higher capacity revenues, combined with substantially increased penalties for non-performance or under-performance during certain periods identified as "capacity performance hours." This linkage between non- or under-performance during certain 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 the potential exists that participation in the CP program could result in capacity penalties that exceed capacity revenues. The purpose of the RPM and 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.
The PJM CP auctions are held three years in advance for a period covering 12 months starting from June 1. Auctions for the period covering June 1, 2019 through May 30, 2020 are expected to take place in May 2016. Future auction results are dependent upon various factors including the demand and supply situation, capacity additions and retirements and any changes in the current auction rules related to bidding for demand response and energy efficiency resources in the capacity auctions. For DPL-owned generation, applicable capacity prices through the auction year 2018/19 are as follows:

Auction Year (June 01-May 31)	2018/19	2017/18	2016/17	2015/16	2014/15	2013/14
Capacity Clearing Price ($/MW-Day)	$165	$152	$134	$136	$126	$28

The computed average capacity prices by calendar year are as follows:

Year	2018	2017	2016	2015	2014
Computed Average Capacity Price ($/MW-Day)	$159	$145	$135	$132	$85

The above tables reflect the capacity prices after the transitional auctions discussed earlier. Substantially all of DP&L's capacity cleared in the CP auction. The results of these auctions could have a significant effect on DP&L's revenues in the future.

According to the terms of DP&L's RPM rider, a portion of the capacity revenue is credited to SSO customers primarily based on the load still being served to the SSO customers. However, with the transition to market, no amount will be credited beginning January 1, 2016.

Regulatory Framework — Retail Regulation — DP&L is subject to regulation by the PUCO, for its distribution services and facilities, retail rates and charges, reliability of service, compliance with renewable energy portfolio, energy efficiency program requirements and certain other matters. DP&L's rates for electric service to retail customers consist of basic rates and charges that are set and approved by the PUCO after public hearings. In addition, DP&L's rates include various adjustment mechanisms including, but not limited to, those to reflect changes in fuel costs to generate electricity or purchased power prices, and the timely recovery of costs incurred to comply with alternative energy, renewables, energy efficiency, and economic development costs. These components function independently of one another, but the overall structure of DP&L's retail rates and charges are subject to the rules and regulations established by the PUCO.

Retail Rate Structure — Since Ohio is deregulated and 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 based on DP&L's Electric Security Plan ("ESP") filing. DP&L's wholesale transmission rates are regulated by the FERC. 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.

The terms and conditions of DP&L's current SSO are provided under the ESP filed in 2012 and approved by the PUCO order dated September 4, 2013 ("2012 ESP"). The 2012 ESP has been in effect since January 2014 and allows DP&L to collect a non-bypassable Service Stability Rider ("SSR") equal to $110 million per year from 2014 - 2016. It allowed for DP&L to recover its PJM-related transmission charges, alternative energy costs, fuel and purchased power costs, and established a SEET ("Significant Excessive Earnings Test") threshold of 12% ROE. It also required DP&L to conduct competitive bid auctions to procure generation supply for SSO service. DP&L's own generation was phased-out of supplying SSO service over the three year period. Beginning January 1, 2016 DP&L's SSO will be 100% sourced through the competitive bid. For calendar years 2012 - 2014, DP&L was subject to a SEET threshold and was required to apply general rules for calculating earnings and comparing them to a comparable group to determine whether there were significantly excessive earnings during a given calendar year. Through the 2012 ESP, the PUCO established DP&L's ROE SEET threshold at 12%. On May 15, 2014, DP&L filed its application to demonstrate that it did not have significantly excessive earnings for calendar year 2013. A stipulation was reached with the PUCO staff agreeing that DP&L did not exceed the SEET threshold for 2014. A hearing was held and the PUCO issued an order approving the SEET stipulation. In future years, the SEET could have a material effect on results of operations, financial condition and cash flows.

On October 30, 2015 DP&L publicly announced its intent to file an application to increase its distribution rates at the PUCO. On November 30, 2015 DP&L filed its distribution rate case using a 12-month test year of June 1, 2015 to May 31, 2016 to measure revenue and expenses and a date certain of September 30, 2015 to measure its asset base. The Company is seeking an increase to distribution revenues of $66 million per year. The Company has asked for recovery of certain regulatory assets as well as two new riders that would allow the Company to recover certain costs on an ongoing basis. It has proposed a modified straight-fixed variable rate design in an effort to decouple distribution revenues from electric sales. If approved as filed the rates are expected to have a total bill impact of approximately 4% on a typical residential customer.

On February 22, 2016 DP&L filed an ESP that would be in effect beginning January 1, 2017. As part of this filing, DP&L is seeking a Reliable Electricity Rider for 10 years, based on the variance between the proposed revenue requirement and the actual revenues net of operating costs of the generation units. This plan establishes the terms and conditions for DP&L's Standard Service Offer (SSO) beginning June 1, 2017 to customers that do not choose a competitive retail electric supplier. In its plan, DP&L recommends including renewable energy attributes as part of the product that is competitively bid, and seeks recovery of approximately $10 million of regulatory assets. The plan also proposes a new Distribution Investment Rider to allow DP&L to recover costs associated with future distribution equipment and infrastructure needs. Additionally, the plan establishes new riders set initially at zero, related to energy reductions from DP&L's energy efficiency programs, and certain environmental liabilities the Company may incur. There can be no assurance that the ESP will be approved as filed or on a timely basis, and if the ESP is not approved on a timely basis or the final ESP provides for terms that are more adverse than those submitted in DP&L’s application, the Company's consolidated results of operations, financial condition and cash flows could be materially impacted.

Environmental Matters — In relation to MATS, 3,066 MW of DPL's generation capacity is largely compliant with MATS, and DPL does not expect to incur material capital expenditures to ensure compliance with MATS. For more information see Item 1.— United States Environmental and Land-Use Legislation and Regulations.

Key Financial Drivers — Although recent ESP and Generation Separation decisions provide some clarity on the underlying drivers through 2016, challenges remain for DPL beyond 2016 including the potential impacts of retail demand, weather, energy efficiency and wholesale prices on financial results. In addition, through 2016, DPL financial results are likely to be driven by many factors including, but not limited to, the following:

- PJM capacity prices auctioned already
- Non-bypassable revenue: $110 million in 2014 and 2015 and allowed to earn $110 million annually in 2016
- Operational performance of generation facilities

Beyond 2016, DPL financial drivers include many factors, such as the following:

- PJM capacity prices
- Recovery in the power market, particularly as it relates to an expansion in dark spreads
- Sale or transfer to a DPL affiliate of DP&L generation assets
- DPL's ability to reduce its cost structure

See Item 1A.—Risk Factors for additional discussion on DPL.

Construction and Development — Planned construction additions primarily relate to new investments in and upgrades to DP&L'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 $439 million in capital projects for the period 2016 through 2018 with 61% 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 WECC, PJM, SPP and Hawaii. AES Southland, in the WECC, is our most significant generating business.

AES Southland

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

Market Structure — All of AES Southland's capacity is contracted through a long-term agreement (the “Tolling Agreement”), which expires in mid-2018. Under the Tolling Agreement, AES Southland's largest revenue driver is unit availability, as approximately 97% of its revenue comes from availability-related payments. 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.

The offtaker under the Tolling Agreement provides gas to the three facilities at no cost; therefore, AES Southland is not exposed to significant fuel price risk. AES Southland does, however, guarantee the efficiency of each unit so that any fuel consumed in excess of what would have been consumed had the guaranteed efficiency been achieved is paid for by AES Southland. Additionally, if the units operate at an efficiency better than the guaranteed efficiency, AES Southland gets credit for the gas that is not consumed. The business is also exposed to the cost of replacement power for a limited time period if any of the plants are dispatched by the offtaker and are not able to meet the required dispatch schedule for generation of electric energy.

AES Southland delivers electricity into the California ISO's market through its Tolling Agreement counterparty.

Re-powering — In October 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. In addition to replacing older gas-fired plants with more efficient gas-fired capacity, SCE chose advanced energy storage as a cost effective way to ensure critical power system reliability. This new storage resource will provide unmatched operational flexibility, enabling the most

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efficient dispatch of other generating plants, lowering cost and emissions and supporting the on-going addition of renewable power sources.

This new capacity will be built at the Company's existing power plant sites in Huntington Beach and Alamitos Beach. For the gas-fired capacity, financing agreements are expected to be finalized in 2016 with construction expected to begin in 2017, and commercial operation scheduled for 2020. For the energy storage capacity, commercial operation is scheduled for 2021.

AES is pursuing permits to build both the gas-fired and energy storage capacity and will complete the licensing process before financial close. The total cost for these projects is expected to be approximately $1.9 billion, which will be funded with a combination of non-recourse debt and AES equity.

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

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

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

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 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 GNPIPD. 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.

US Wind — AES has 773 MW of wind capacity in the U.S., located in California, Texas and West Virginia. In July 2015, AES sold its interest in Armenia Mountain, a wind project located in Pennsylvania with an installed capacity of 101 MW. Typically, these facilities sell under long-term PPAs. AES financed most of these projects with 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 a net loss to AES consolidated results in periods in which the facilities report net income. These non cash net losses will be expected to reverse during the life of the facilities. Some of the wind projects are exposed to the volatility of energy prices and their revenue may change materially as energy prices fluctuate in their respective markets of operations.

Buffalo Gap is located in Texas and is comprised of three wind projects with an aggregate generation capacity of 524 MW. Each wind project operates its own PPA with the exception of Buffalo Gap III whose PPA expired in December 2015. The energy price of the entire production of Buffalo Gap I is guaranteed by a PPA expiring in 2021. The PPA of Buffalo Gap II guarantees the energy price of 80% of the installed capacity while the energy price for the remaining 20% is dictated by the prices in the ERCOT market. The PPA of Buffalo Gap II expires in December 2017. Once the PPAs expire, the entire installed capacity of Buffalo Gap will be exposed to the volatility of energy prices in the ERCOT market which could adversely affect revenues.

Laurel Mountain is a wind project located in West Virginia with an installed capacity of 98 MW. Laurel Mountain does not operate under a long-term contract and sells its entire capacity and power generated into the PJM market. The volatility and fluctuations of energy prices in PJM have a direct impact in the results of Laurel Mountain.

AES manages the wind 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 wind industry to achieve optimal results.
Market Structure — Coal is one of the primary fuels used by our U.S. generation facilities that has international prices set by market factors, although the price of the other primary fuel, 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, and the prices of these fuels have been subject to volatility in recent years. Many of these generation businesses have entered into long-term

PPAs with utilities or other offtakers. Some coal-fired power plant businesses in the U.S. with PPAs have mechanisms to recover fuel costs from the offtaker, including an energy payment that is partially based on the market price of coal. In addition, 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. Revenue may change materially as prices in fuel markets fluctuate, but the variable margin or profitability should not be materially changed when market price fluctuations in fuel are borne by the offtaker.

Regulatory Framework — Several of our generation businesses in the U.S. currently operate as QFs as defined under the PURPA. These businesses entered into long-term contracts with electric utilities that had a mandatory obligation under PURPA requirements 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 EWG 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 FPA 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. To prevent market manipulation, FERC requires sellers with market-based rate authority to file certain reports, including a triennial updated market power analysis for markets in which they control certain threshold amounts of generation.

Other Regulatory Matters — The U.S. wholesale electricity market consists of multiple distinct regional markets that are subject to both federal regulation, as implemented by the U.S. 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.

Our businesses are subject to emission regulations, which may result in increased operating costs or the purchase of additional pollution control equipment if emission levels are exceeded. Our businesses periodically review their obligations for compliance with environmental laws, including site restoration and remediation. Because of 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, if any. For a discussion of environmental laws and regulations affecting the U.S. business, see Item 1.—US Environmental and Land-Use Legislation and Regulations.

Key Financial Drivers — U.S. 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 US 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.

Construction and Development — Planned capital projects include the AES Southland re-powering described above. In addition to the new construction projects, 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

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.

Our Andes operations accounted for the following proportions of consolidated AES Operating Margin, AES Adjusted PTC (a non-GAAP measure), AES Operating Cash Flow, and AES Proportional Free Cash Flow (a non-GAAP measure):

Andes SBU [1]	2015		2014		2013	
% of AES Operating Margin	22	%	19	%	17	%
% of AES Adjusted PTC (a non-GAAP measure)	30	%	23	%	19	%
% of AES Operating Cash Flow	18	%	16	%	11	%
% of AES Proportional Free Cash Flow (a non-GAAP measure)	14	%	13	%	10	%

[1] Percentages reflect the contributions by our Andes SBU before deductions for Corporate.

The following table provides highlights of our Andes operations:

Countries	Chile, Colombia and Argentina
Generation Capacity	8,141 gross MW (6,008 proportional MW)
Generation Facilities	38 (including 5 under construction)
Key Generation Businesses	AES Gener Chile, Chivor and AES Argentina

Operating installed capacity of our Andes SBU totals 8,141 MW, of which 44%, 44% and 12% is located in Argentina, Chile and Colombia, respectively. Presented in the table below is a list of our Andes SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest (% Rounded)		Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Chivor	Colombia	Hydro	1,000	67	%	2000	Short-term	Various
Colombia Subtotal			1,000					
Electrica Santiago[1]	Chile	Gas/Diesel	750	67	%	2000		
Gener - SIC[2]	Chile	Hydro/Coal/Diesel/Biomass	692	67	%	2000	2020-2037	Various
Guacolda[3]	Chile	Coal/Pet Coke	760	33	%	2000	2017-2032	Various
Electrica Angamos	Chile	Coal	558	67	%	2011	2026-2037	Minera Escondida, Minera Spence, Quebrada Blanca
Gener - SING[4]	Chile	Coal/Pet Coke	277	67	%	2000	2016-2037	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
Electrica Angamos ES	Chile	Energy Storage	20	67	%	2011		
Gener - Norgener ES (Los Andes)	Chile	Energy Storage	12	67	%	2009		
Chile Subtotal			3,613					
TermoAndes[7]	Argentina	Gas/Diesel	643	67	%	2000	Short-term	Various
AES Gener Subtotal			5,256					
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		
Los Caracoles[8]	Argentina	Hydro	125	—	%	2009	2019	Energia Provincial Sociedad del

						Estado (EPSE)
Cabra Corral	Argentina	Hydro	102	100 %	1995	
Ullum	Argentina	Hydro	45	100 %	1996	
Sarmiento	Argentina	Gas/Diesel	33	100 %	1996	
El Tunal	Argentina	Hydro	10	100 %	1995	
Argentina Subtotal			2,885			
Andes Total			8,141			

(1) Electrica Santiago plants: Nueva Renca, Renca, Los Vientos and Santa Lidia.

(2) Gener - SIC plants: Alfalfal, Laguna Verde, Laguna Verde Turbogas, Laja, Maitenes, Queltehues, Ventanas 1, Ventanas 2 and Volcán.

(3) Guacolda plants: Guacolda 1, 2, 3, 4, and 5. Unconsolidated entities for which the results of operations are reflected in 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%.

(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 (% Rounded)		Expected Year of Commercial Operations
Cochrane	Chile	Coal	532	40	%	2H 2016
Alto Maipo	Chile	Hydro	531	40	%	2H 2018/1H 2019
Andes Solar	Chile	Solar	21	67	%	1H 2016
Cochrane ES	Chile	Energy Storage	20	40	%	2H 2016
Chile Subtotal			1,104			
Tunjita	Colombia	Hydro	20	67	%	1H 2016
Colombia Subtotal			20			
Andes Total			1,124			

The following map illustrates the location of our Andes facilities:

Andes Businesses

Chile

Business Description — In Chile, through AES Gener, we are engaged in the generation and supply of electricity (energy and capacity) in the two principal markets: the SIC and SING. In terms of aggregate installed capacity, AES Gener is the second largest generation operator in Chile with a calculated installed capacity of 3,581 MW, excluding energy storage and TermoAndes, and a market share of 17.7% as of December 31, 2015.

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, composed of hydroelectric, coal, gas, diesel and biomass facilities, allows the businesses to operate under a variety of market and hydrological conditions, manage AES Gener's contractual obligations with regulated and unregulated customers and, as required, provide backup spot market energy. AES Gener has experienced significant growth in recent years responding to market opportunities with the completion of nine generation projects totaling approximately 1,861 MW, including the 152 MW Unit 5 of Guacolda completed in December 2015, and increasing AES Gener's installed capacity by 55% from 2006 to 2015. Additionally, we are constructing an additional 1,104 MW, comprised of the 21 MW Andes Solar and 20 MW Cochrane Energy Storage in the SING, the 532 MW coal-fired Cochrane plant in the SING and the 531 MW Alto Maipo run-of-the-river hydroelectric plant in the SIC.

In Chile, we align AES Gener's contracts to reduce the risk and improve margins, contracting a significant portion of their baseload capacity, currently coal and hydroelectric, under long-term contracts with a diversified customer base, including both regulated and unregulated customers. AES Gener reserves its higher variable cost units as designated backup facilities, principally the diesel- and gas-fired units in Chile, for sales to the spot market during scarce system supply conditions, such as dry hydrological conditions and plant outages. In Chile, sales on the spot market are made only to other generation companies that are members of the relevant CDEC at the system marginal cost.

AES Gener currently has long-term contracts, with average terms of 13 to 16 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 along with indexation mechanisms that periodically adjust prices based on the generation cost structure related to the CPI, the international price of coal, and in some cases, with pass-through of fuel and regulatory costs, including changes in law.

In addition to energy payments, AES Gener also receives firm capacity payments for contributing to the system's ability to meet peak demand. These payments are added to the final electricity price paid by both unregulated and regulated customers. In each system, the CDEC annually determines the firm capacity amount allocated to each power plant. A plant's firm capacity is defined as the capacity that it can guarantee at peak hours during critical conditions, such as droughts, taking into account statistical information regarding maintenance periods and water inflows in the case of hydroelectric plants. The capacity price is fixed by the CNE in the semiannual node price report and indexed to the CPI and other relevant indices.

During November, 2015, AES successfully completed the sale of 4% interest in AES Gener S.A. through its direct shareholder Inversiones Cachagua S.p.A. ("Cachagua") through a private auction. The strategic rationale of this sale was to increase the liquidity of the AES Gener's Share and its exposure on international markets. As a result of this transaction AES now owns 66.7% of AES Gener.

Market Structure — Chile has two main power systems, largely as a result of its geographic shape and size. The SIC is the largest of these systems, with an installed capacity of 15,911 MW as of December 31, 2015. The SIC serves approximately 92% of the Chilean population, including the densely populated Santiago Metropolitan Region, and represents 74% of the country's electricity demand. The SING serves about 6% of the Chilean population, representing 25% of Chile's electricity consumption, and is mostly oriented toward mining companies.

In 2015, thermoelectric generation represented 62% of the total generation in Chile. In the SIC, thermoelectric generation represents 50% of installed capacity, 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 96% of installed capacity. The fuels used for generation, mainly coal, diesel and LNG, are indexed to international prices.

In the SIC, where hydroelectric plants represent a large part of the system's installed capacity, hydrological conditions largely influence plant dispatch and, therefore, spot market prices, given that river flow volumes, melting snow and initial water levels in reservoirs largely determine the dispatch of the system's hydroelectric and thermoelectric generation plants. Rainfall and snowfall occur in Chile principally in the southern cone winter season (June to August) and during the remainder of the year precipitation is scarce. When rain is abundant, energy produced by hydroelectric plants can amount to more than 70% of total generation. In 2015 hydroelectric generation represented 45% of total energy production.

Regulatory Framework — Electricity Regulation — The government entity that has primary responsibility for the Chilean electricity system is the Ministry of Energy, acting directly or through the CNE and the Superintendency of Electricity and Fuels. The electricity sector is divided into three segments: generation, transmission and distribution. In general terms, generation and transmission expansion are subject to market competition, while transmission operation and distribution, are subject to price regulation. The transmission segment consists of companies that transmit the electricity produced by generation companies at high voltage. Companies that are owners of a trunk transmission system, generally high voltage transmission lines with capacity of 220 Kv and higher (with bi-directional flows and relevant number of users), cannot participate in the generation or distribution segments.

Companies in the SIC and the SING that possess generation, transmission, sub-transmission or additional transmission facilities, as well as unregulated customers directly connected to transmission facilities, are coordinated through the CDEC, which minimizes the operating costs of the electricity system, while meeting all service quality and reliability requirements. The principal purpose of the CDEC is to ensure that the most efficient electricity generation available to meet demand is dispatched to customers. The CDEC dispatches plants in merit order based on their variable cost of

production which allows for electricity to be supplied at the lowest available cost.
All generators can commercialize energy through contracts with distribution companies for their regulated and unregulated customers or directly with unregulated customers. Unregulated customers are customers whose connected capacity is higher than 2 MW. By law, both regulated and unregulated customers are required to purchase all of their electricity requirements under contract. Generators may also sell energy to other power generation companies on a short-term basis. Power generation companies may engage in contracted sales among themselves at negotiated prices outside the spot market. Electricity prices in Chile, under contract and on the spot market, are denominated in U.S. Dollars, although payments are made in Chilean Pesos.

Other Regulatory Considerations — In 2011, a regulation on air emission standards for thermoelectric power plants became effective. This regulation provides for stringent limits on emission of PM and gases produced by the combustion of solid and liquid fuels, particularly coal. For existing plants, including those currently under construction, the new limits for PM emissions went into effect at the end of 2013, and the new limits for SO_2, NO_x and mercury emission will begin to apply in mid-2016, except for those plants operating in zones declared saturated or latent zones (areas at risk of or affected by excessive air pollution), where these emission limits will become effective by June 2015. In order to comply with the new emission standards, AES Gener initiated investments in Chile at its older coal facilities (Ventanas I and II and Norgener I and II, constructed between 1964 and 1997) in 2012. As of December 31, 2015, AES Gener has concluded investments of approximately $229 million in order to comply within the required time frame. Additionally, its equity method investee Guacolda started the installation of new equipment during 2013, spending approximately $185 million (Guacolda I, II and IV) as of December 31, 2015 with the remaining $37 million to be invested in 2016.

Chilean law requires every electricity generator to supply a certain portion of its total contractual obligations with NCREs. In October 2013, the NCRE law was amended, increasing the NCRE requirements. The law distinguishes between energy contracts executed before and after July 1, 2013. For contracts executed between August 31, 2007 and July 1, 2013, the NCRE requirement is equal to 5% in 2014 with annual contract increases of 0.5% until reaching 10% in 2024. The NCRE requirement for contracts executed after July 1, 2013 is equal to 5% in 2013, with annual increases of 1% thereafter until reaching 12% in 2020, and subsequently annual increases of 1.5% until it is equal to 20% in 2025. Generation companies are able to meet this requirement by developing their own NCRE generation capacity (wind, solar, biomass, geothermal and small hydroelectric technology), purchasing NCREs from qualified generators or by paying the applicable fines for non-compliance. AES Gener currently fulfills the NCRE requirements by utilizing AES Gener's own biomass power plants and by purchasing NCREs from other generation companies. It has sold certain water rights to companies that are developing small hydro projects, entering into power purchase agreements with these companies in order to promote development of these projects, while at the same time meeting the NCRE requirements. At present, AES Gener is in the process of negotiating additional NCRE supply contracts to meet the future requirements.

In September 2014 a new tax law was enacted. The new law introduces an emission tax, or "green tax", that assesses the emissions of PM, SO_2, NO_x and CO_2 produced for installations with an installed capacity over 50 MW. The first annual payment shall be made in April 2018, regarding the emissions produced during year 2017. In the case of CO_2, the tax will be equivalent to $5 per ton emitted. In the SING, all PPAs have "change of law" clauses, which would allow the company to transfer this cost to customers. In the SIC, costs can only be passed through to unregulated customers, as existing PPAs with discos do not have change of law clauses. According to its PPAs, the company is currently discussing the pass-through mechanism with each client. Additionally, new tax laws were enacted in February 2016 in Chile which will increase the statutory income tax rate for most of our Chilean businesses from 25% to 25.5% in 2017 and to 27% for 2018 and future years. See Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Income Taxes for further details of the impacts of these new laws.

In June 2015, the Chilean government published Decree N°7/2015, which allowed energy exportation to Argentina using the transmission line which connects the SING (Chilean Northern Grid) with the SADI (Argentine Grid). The AES transmission line has a capacity of approximately 600MW, but will be operated at 200 MW according to technical studies. AES Gener signed an agreement with CAMMESA and other generators (Gas Atacama and ECL) in order to export electricity to Argentina.

Key Financial Drivers — Hedge levels at Gener provide some certainty and clarity on the underlying financial drivers through 2016. However, some risks remain through 2016, including, but not limited to, the following:

- Dry hydrology scenarios reduce hydro generation (See Item 7.—Key Trends and Uncertainties— Operational—Weather sensitivity for further discussion)
- Forced outages may impact earnings
- Changes in current regulatory rulings could alter the ability to pass through or recover certain costs

- AES is exposed to the fluctuation of the Chilean peso, which may pose a risk to earnings; our hedging strategy reduces this risk, but some residual risk to earnings remains
- Tax policy changes

Beyond 2016, financial drivers include all of the above factors, but also:

- Current legislation is trending towards promoting renewable energy and strengthening regulations on thermal generation assets, posing a risk to future coal margins
- Market price risk when re-contracting

Construction and Development — Since 2007, AES Gener has constructed and initiated commercial operations of approximately 1,830 MW of new capacity, representing a significant portion of the increase in installed capacity and investment in the SIC and SING during the period. In Chile, AES Gener has a 21 MW solar project with a scheduled COD in the first half of 2016 and the 532 MW Cochrane project in the SING, expected to begin operations in 2016. The Cochrane project has an adjacent 20 MW energy storage project, which is also scheduled to initiate operations in 2016.

Additionally, in the SIC, AES Gener initiated construction of the 531 MW two unit Alto Maipo run-of-river hydroelectric project in December 2013, adjacent to our existing Alfalfal power plant, located 50 km from Santiago. Alto Maipo is the largest project in construction in the SIC market and it includes 67 kilometers of tunnel works, 2 caverns, 17 km of transmission lines as part of the construction, and is 90% underground. Alto Maipo has three main contractors and covers three adjacent valleys in the Chilean Andes. As of today, the project employs 4,100 people and expects to reach a peak close to 4,500 in the second half of 2017. The project units are scheduled to reach commercial operation in the second half of 2018 and the first half of 2019.

Colombia

Business Description — Chivor, a subsidiary of AES Gener, owns a hydroelectric facility with installed capacity of 1,000 MW, located approximately 160 km east of Bogota. As of December 31, 2015, AES Gener's net power production in Colombia was 4,112 GWh. The installed capacity represents approximately 6.2% of system capacity as of December 31, 2015. The plant consists of eight 125 MW dam-based hydroelectric generating units in two separate sub-facilities. All of Chivor's installed capacity in Colombia is hydroelectric and is therefore dependent on the prevailing hydrological conditions in the region in which it operates. Hydrological conditions largely influence generation and the spot prices at which Chivor sells its non-contracted generation in Colombia.

Chivor's commercial strategy focuses a significant portion of the expected output under contracts, principally with distribution companies, in order to provide cash flow stability. These bilateral contracts with distribution companies are awarded in public bids and normally last from one to three years. The remaining generation is sold on the spot market to other generation and trading companies at the system marginal cost, allowing us to maximize the operating margin.

Additionally, Chivor receives reliability payments for the availability and reliability of Chivor's reservoir during periods of scarcity, such as adverse hydrological conditions. These payments, referred to as "reliability charge payments" are designed to compensate generation companies for the firm energy that they are capable of providing to the system during critical periods of low supply in order to prevent electricity shortages.

Market Structure — Electricity supply in Colombia is concentrated in one main system, the SIN. The SIN encompasses one-third of Colombia's territory, providing coverage to 96% of the country's population. The SIN's installed capacity totaled 16,221 MW as of December 31, 2015, comprised of 69.0% hydroelectric generation, 30.4% thermoelectric generation and 0.6% other. The dominance of hydroelectric generation and the marked seasonal variations in Colombia's hydrology result in price volatility in the short-term market. In 2015, 68.2% of total energy demand was supplied by hydroelectric plants with the remaining supply from thermoelectric generation (31.0%) and cogeneration and self-generation power (0.8%). From 2003 to 2015, electricity demand in the SIN has grown at a compound annual growth rate of 3.1% and the UPME projects an average compound annual growth rate in electricity demand of 2.8% per year for the next ten years.

Regulatory Framework — Electricity Regulation — Since 1994, the electricity sector in Colombia has operated 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 various laws and the regulations and technical standards issued by the CREG. Other government entities that play an important role in the electricity industry include the MME, which defines the government's policy for the energy sector; the Public Utility Superintendency of Colombia, which is in charge of overseeing and inspecting the utility companies; and the UPME, which is in charge of planning the 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. Generation companies must submit price bids and report the quantity of energy available on a daily basis. 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.

Other Regulatory Considerations — In the past few years, Colombian authorities have discussed proposals to make certain regulatory changes, which have not been implemented as of December 2015. One proposal is to replace or complement the current public auction system in which each distribution company holds an auction for its specific requirements and subsequently executes bilateral contracts with generation or trading companies, with a centralized auction in which the market administrator purchases energy for all distribution companies. During 2015, regulators developed rules to implement Law 1715 passed in 2014 regarding the participation of renewables sources in the electric sector and the rules for negotiation of excess of energy from self-generators. Due to very high spot prices in the market, the regulator implemented a temporary "spot price cap" equivalent to the 75% of the first step of rationing cost. At the end of 2015, CREG assigned new firm energy obligations for the next 3 years (2017-2019). Additionally, regulation for emergency energy situations, such as severe drought conditions, was introduced in 2014 with the objective of avoiding shortages and other negative economic impacts. For 2016, the most probable changes in regulation will relate to the AGC ancillary services market as well as a general revision of the reliability charge scheme.

Key Financial Drivers — Hydrological conditions largely influence Chivor's generation level. Maintaining the appropriate contract level, while working to maximize revenue, through sale of excess generation, is key to Chivor's results of operations (see Item 7.—Key Trends and Uncertainties—Operational—Weather sensitivity for further discussion). Hedge levels at Chivor provide certainty and clarity on the underlying financial drivers, hedging the net cash flows of Chivor, up to 90%. However, some risks remain beyond 2016. In addition to hydrology, through 2016, financial results are likely to be driven by many factors including, but not limited to, the following:

- Forced outages may impact earnings
- AES is exposed to fluctuation of the Colombian peso, which pose a risk to earnings; our hedging strategy reduces this risk, but some residual risk to earnings remains

Beyond 2016, financial drivers include all of the above factors, but also:

- Chivor has exposure to the spot market as hedge levels are lower in the future

Construction and Development — In Colombia, AES Gener is currently constructing the 20 MW Tunjita run-of-river hydroelectric project, which is scheduled to start operations in the first half of 2016.

Argentina

Business Description — As of December 31, 2015, AES Argentina operates 3,528 MW which represents 10.5% 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. AES Argentina has a diversified generation portfolio of ten generation facilities, comprised of 62% thermoelectric and 38% hydroelectric capacity. All of the thermoelectric capacity has the capability to burn alternative fuels. Approximately 69% of the thermoelectric capacity can operate alternatively with natural gas or diesel oil, and the remaining 31% can operate alternatively with natural gas, fuel oil, or coal.

AES Argentina primarily sells its production to the wholesale electric market where prices are largely regulated. In 2015, approximately 93% of the energy was sold in the wholesale electric market and 7% was sold under contract, as a result of the Energy Plus sales made by TermoAndes. Market prices are determined in Argentine Pesos by CAMMESA, the wholesale electric market administrator.

All of the thermoelectric facilities not affected by the Resolution 95/2013, a regulation passed in March 2013 discussed below, including the portion of TermoAndes plant committed to Energy Plus Contracts, are able to use natural gas and receive gas supplied through contracts with Argentine producers. In recent years, gas supply restrictions in Argentina, particularly during the winter season, have affected some of the plants, such as the TermoAndes plant which is connected to the SING by a transmission line owned by AES Gener. The TermoAndes plant commenced operations in 2000, selling exclusively into the Chilean SING. In 2008, following requirements from the Argentine authorities, TermoAndes connected its two gas turbines to the SADI, while maintaining its steam turbine connected to the SING. However, since mid-December 2011, TermoAndes has been selling the plant's full capacity in the SADI. TermoAndes' electricity permit to export to the SING expired on January 31, 2013 and its potential renewal is being evaluated.

Market Structure — The SADI electricity market is managed by CAMMESA. As of December 31, 2015, the installed capacity of the SADI totaled 33,480 MW. In 2015, 64% of total energy demand was supplied by thermoelectric plants, 31% by hydroelectric plants and 6% from nuclear, wind and solar plants.

Thermoelectric generation in the SADI is principally fueled by natural gas. However, since 2004 due to natural gas shortages, in addition to increasing electricity demand, the use of alternative fuels in thermoelectric generation, such as oil and coal, has increased. Given the importance of hydroelectric facilities in the SADI, hydrological conditions determining river flow volumes and initial water levels in reservoirs largely influence hydroelectric and thermoelectric plant dispatch. Rainfall occurs principally in the southern cone winter season (June to August).

Regulatory Framework — Electricity Regulation — 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 allowed to buy and sell electricity. Generation companies can sell their output in the short-term market or to customers in the contract market. CAMMESA is responsible for dispatch coordination and determination of short-term prices. The Electricity National Regulatory Agency is in charge of regulating

public service activities and the Ministry of Federal Planning, Public Investment and Services, through the Energy Secretariat, regulates system dispatch and grants concessions or authorizations for sector activities.
Since 2001, significant modifications have also been made to the electricity regulatory framework. These modifications include tariff conversion to Argentinean Pesos, freezing of tariffs, the cancellation of inflation adjustment mechanisms and the introduction of a complex pricing system in the wholesale electric market, which have materially affected electricity generators, transporters and distributors, and generated substantial price differences within the market. Since 2004, as a result of energy market reforms and overdue accounts receivables owed by the government to generators operating in Argentina, AES Argentina contributed certain accounts receivables 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 operations. At this point, three funds have been created to construct three facilities. The first two plants are operating and payments are being received, while the third plant is in late stages of the construction process. AES Argentina will receive a pro rata ownership interest in these newly built plants once the accounts receivables have been paid. See Item 7.—Capital Resources and Liquidity—Long-Term Receivables and Note 7—Financing Receivables for further discussion of receivables in Argentina.
On March 26, 2013, the Secretariat of Energy released Resolution 95/2013, which affects the remuneration of generators whose sales prices had been frozen since 2003. This new regulation, which modified the current regulatory framework for the electricity industry, is applicable to generation companies with certain exceptions. It defined a new compensation system based on compensating for fixed costs, non-fuel variable costs and an additional margin. Resolution 95/2013 converted the Argentine electric market towards an "average cost" compensation scheme, increasing revenues of generators that were not selling their production under the Energy Plus scheme or under energy supply contracts with CAMMESA. Resolution 95/2013 applied to all of AES Argentina's plants, excluding TermoAndes. Based on Note 2053 sent by the Ministry of Energy in March 2013, it was understood that TermoAndes' units were not affected by the Resolution since they sell under the Energy Plus scheme.
Thermal units must achieve an availability target which varies by technology in order to receive full fixed cost revenues. The availability of most of AES Argentina's units exceeds this market average. As a result of Resolution 95/2013, revenues to AES Argentina's thermal units increased, but the impact on hydroelectric units is dependent on hydrology. The new Resolution also established that all fuels, except coal, are to be provided by CAMMESA. Thermoelectric natural gas plants not affected by the Resolution, such as TermoAndes, are able to purchase gas directly from the producers for Energy Plus sales.
On May 20, 2014, the Argentine government passed Resolution No. 529/214 ("Resolution 529") which retroactively updated the prices of Resolution 95/2013 to February 1, 2014, changed target availability and added a remuneration for non-periodic maintenance. This renumeration is aimed to cover the expenses that the generator incurs when performing major maintenances in its units.
In the fourth quarter of 2014, the Argentine government passed a resolution to contribute outstanding Resolution 95 receivables into a trust in connection with AES Argentina's commitment to install additional capacity into the system. CAMMESA will finance the investment utilizing the outstanding receivables as a guarantee.
On July 10, 2015, the Argentine government passed Resolution No. 482/2015 ("Resolution 482") which retroactively updated the prices of Resolution 529/2014 to February 1, 2015, including the portion of TermoAndes plant energy generation not committed to Energy Plus Contracts, and created a new trust called "Recursos para las inversions del FONINVEMEM 2015-2018" in order to invest in new generation plants.
In December 2015, the new finance minister lifted foreign currency controls, allowing the peso to float under the administration of Argentinean Central Bank. The newly freed currency fell by more than 30%. Over the course of 2015, the Argentinean Peso devalued by approximately 50%. At December 31, 2015, all transactions at our businesses in Argentina were translated using the official exchange rate published by the Argentine Central Bank. See Note 7—Financing Receivables in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information on the long-term receivables. Further weakening of the Argentine Peso and local economic activity could cause significant volatility in our results of operations, cash flows, the ability to pay dividends to the Parent Company, and the value of our assets.

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

- Forced outages may impact earnings
- FX exposure to fluctuations of the Argentine Peso
- Hydrology
- Timely collection of FONINVEMEM installment and outstanding receivables (See Note 7—Financing Receivables in Item 8.—Financial Statements and Supplementary Data for further discussion)
- Level of gas prices for contracted generation (Energy Plus)

- Regulatory changes from new government (See Item 7.—Key Trends and Uncertainties—Macroeconomics— Argentina for further discussion)

Brazil SBU

Our Brazil SBU has generation and distribution businesses. Eletropaulo and Tietê are publicly listed companies in Brazil. AES has a 16% economic interest in Eletropaulo and a 24% economic interest in Tietê, and these businesses are consolidated in our financial statements as we maintain control over their operations. Our Brazil operations accounted for the following proportions of consolidated AES Operating Margin, AES Adjusted PTC (a non-GAAP measure), AES Operating Cash Flow, and AES Proportional Free Cash Flow (a non-GAAP measure):

Brazil SBU [1]	2015		2014		2013	
% of AES Operating Margin	21	%	24	%	27	%
% of AES Adjusted PTC (a non-GAAP measure)	6	%	13	%	12	%
% of AES Operating Cash Flow	5	%	14	%	26	%
% of AES Proportional Free Cash Flow (a non-GAAP measure)	NM[2]		1	%	6	%

(1) Percentages reflect the contributions by our Brazil SBU before deductions for Corporate.
(2) Not meaningful

The following table provides highlights of our Brazil operations:

Generation Capacity	3,298 gross MW (932 proportional MW)
Generation Facilities	13
Key Generation Businesses	Tietê and Uruguaiana
Utilities Penetration	8.2 million customers (56,861 GWh)
Utility Businesses	2
Key Utility Businesses	Eletropaulo and Sul

Generation — Operating installed capacity of our Brazil SBU totals 2,658 MW in AES Tietê plants, located in the state of São Paulo. As of December 31, 2015, Tietê represents approximately 12% of the total generation capacity in the state of São Paulo and is the third largest private generator in Brazil. We also have another generation plant, AES Uruguaiana, located in southern Brazil with an installed capacity of 640 MW. Listed below are our Brazil SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest (% Rounded)		Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Tietê[1]	Brazil	Hydro	2,658	24	%	1999	2029	Various
Uruguaiana	Brazil	Gas	640	46	%	2000		
Brazil Total			3,298					

(1) Tietê plants with installed capacity: 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).

Utilities — AES owns interests in two distribution businesses in Brazil, Eletropaulo and Sul. Eletropaulo operates in the metropolitan area of São Paulo and adjacent regions, distributing electricity to 24 municipalities in a total area of 4,526 km^2, covering a region of high demographic density and the largest concentration of GDP in the country. Serving approximately 20 million people and 6.9 million consumer units, Eletropaulo is the largest power distributor in Brazil, according to the 2012 ranking of the Brazilian Association of the Distributors of Electric Energy (Abradee). Sul is responsible for supplying electricity to 118 municipalities of the metropolitan region of Porto Alegre on the border with Uruguay and Argentina. The service area covers 99,512 km^2, serving approximately 3.7 million people and 1.3 million consumer units.

Presented in the table below is a list of our Brazil SBU distribution facilities:

Business	Location	Approximate Number of Customers Served as of 12/31/2015	GWh Sold in 2015	AES Equity Interest (% Rounded)		Year Acquired
Eletropaulo	Brazil	6,852,690	47,357	16	%	1998
Sul	Brazil	1,308,224	9,504	100	%	1997
		8,160,914	56,861			

The following map illustrates the location of our Brazil facilities:
Brazil Generation Businesses
Business Description — Tietê has a portfolio of 12 hydroelectric power plants with total installed capacity of 2,658 MW in the state of São Paulo. Tietê was privatized in 1999 under a 30-year concession expiring in 2029. AES owns a 24% economic interest in Tietê, our partner, the BNDES, owns 28% and the remaining shares are publicly held or held by government-related entities. AES is the controlling shareholder and manages and consolidates this business.
Tietê sold nearly 100% of its assured capacity, approximately 11,1194 GWh, to Eletropaulo under a long-term PPA, which expired in December 2015. The contract was price-adjusted annually for inflation, and as of December 31, 2015, the price was R$218/MWh. After the expiration of contract with Eletropaulo, Tietê's strategy is to contract most of its Assured Energy, as described in Regulatory Framework section below, in the free market and sell the remaining portion in the spot market. Tietê's strategy is reassessed from time to time according to changes in market conditions, hydrology and other factors. Tietê has been continuously selling its available energy from 2016 forward through medium-term bilateral contracts (3-5 years).
As of December 31, 2015, Tietê's contracted portfolio position is 95% and 88% with average prices of R$149/MWh and R$150/MWh for 2016 and 2017, respectively. As Brazil is mostly a hydro-based country with energy prices highly tied to the hydrological situation, the deterioration of the hydrology since the beginning of 2014 caused an increase in energy prices going forward. Tietê is closely monitoring and analyzing system supply conditions to support energy commercialization decisions. In 2015, 12 new contracts were signed at an average price of approximately R$154/MWh.Tietê's strategy is to contract most of its physical guarantee in the free market while the remaining portion provides flexibility to either protect against low hydrology or potentially capture higher spot prices in the future. As Brazil does not have a developed market with hedge and options instruments for the energy sector, Tietê does not assume any hedging strategy for its portfolio.
Under the concession agreement, Tietê has an obligation to increase its capacity by 15%. Tietê as well as other concessionaire generators have not yet met this requirement due to regulatory, environmental, hydrological and fuel constraints. Sao Paulo state does not have a good potential for wind power and also only a small remaining potential for hydro projects, directing the new increase in the state for thermal capacity. With the high complexity process to get an environmental license for coal projects, Tietê decided to fulfill obligation with gas-fired projects in line with Federal government plans. As Petrobras refuses to supply natural gas and to offer capacity in its pipelines and regasification terminals and there are no regulations for natural gas swaps in place, up to now, it is unfeasible to bring natural gas to AES Tietê. A legal case has been initiated by the State of São Paulo requiring the investment to be performed. Tietê is in the process of analyzing options to meet the obligation.
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, commissioned in December 2000. AES manages and has a 46% economic interest in the plant with the remaining interest held by BNDES. The plant's operations were suspended in April 2009 due to the unavailability of gas. 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. The plant operated on a short-term basis in 2013 during February and March, in 2014 during March, April, and May, and in 2015 during February, Mach, April and May due to the short-term supply of LNG for the facility. Uruguaiana continues to work toward securing gas on a long-term basis.

Market Structure — Brazil has installed capacity of 140,272 MW, which is 65% hydroelectric, 21.6% thermal and 13.4% renewable (biomass and wind). Brazil's national grid is divided into four subsystems. Tietê is in the Southeast subsystem of the national grid, while Uruguaiana is in the South.

Regulatory Framework — In Brazil, the MME determines the maximum amount of energy that a plant can sell, called Assured Energy, which represents the long-term average expected energy production of the plant. Under current rules, a generation plant's Assured 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 coordinating and controlling the operation of the national grid. The ONS dispatches generators based on hydrological conditions, reservoir levels, electricity demand and the prices of fuel and thermal generation. Given the importance of hydro generation in the country, the ONS sometimes reduces dispatch of hydro facilities and increases dispatch of thermal facilities to protect reservoir levels in the system.

In Brazil, the system operator controls all hydroelectric generation dispatch and reservoir levels, and a mechanism known as MRE was created to share hydrological risk across all hydro generators. If the hydro system generates less than total Assured Energy of the system, hydro generators may need to purchase energy in the short-term market to fulfill their contract obligations. When total hydro generation is higher than the total MRE Assured Energy, the surplus is proportionally shared among its participants and they are able to make extra revenue selling the excess energy on the spot market. The consequences of unfavorable hydrology are (i) thermal plants (more expensive to the system) being dispatched, (ii) lower hydropower generation with deficits in the MRE and (iii) high spot prices.

Due to lower than expected hydrology during 2014, from February to April the spot price was at the cap of R$822/MWh and the average spot price of 2014 was R$689/MWh. During October and November 2014, the ANEEL conducted a public hearing to define a new spot price cap, changing it from R$822/MWh to R$388/MWh from January 2015 until December 2015. The lower cap price resulted in a meaningful reduction on the expenses of the agents that were negatively exposed to the spot price in 2015. However, due to improved hydrology in the second half of 2015 spot prices were below the cap with the average price of R$287/MWh. For 2016, ANEEL has already defined the new spot price cap, changing it from R$388/MWh to R$423/MWh from January 2016 forward.

Key Financial Drivers — As the system is highly dependent on hydroelectric generation, Tietê and Uruguaiana (more likely to generate during low hydrology) are affected by the hydrology in the overall sector, as well as the availability of Tietê's plants and reliability of the Uruguaiana facility. The availability of gas for continued operations is a driver for Uruguaiana.

Through and beyond 2016, Tietê's financial results are likely to be driven by many factors including, but not limited to, the following:

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

Through and beyond 2016, Uruguaiana's financial results are likely to be driven by many factors including, but not limited to, the following:

- Arbitration settlement with YPF (see Item 3.—Legal Proceedings)
- Secure long-term gas solution

Brazil Utility Businesses

Business Description — Eletropaulo distributes electricity to the greater São Paulo area, Brazil's main economic and financial center. Eletropaulo is the largest electric power distributor in Latin America in terms of both revenues and volume of energy distribution.

AES owns 16% of the economic interest in Eletropaulo, our partner, BNDES, owns 19% and the remaining shares are publicly held or held by government-related entities. AES is the controlling shareholder and manages and consolidates this business. Eletropaulo holds a 30-year concession that expires in 2028.

AES owns 100% of Sul. Sul distributes electricity in the metropolitan region of Porto Alegre up to the frontier with Uruguay and Argentina, respectively, in the municipalities of Santana do Livramento and Uruguaiana/São Borja at the extreme west of the state of Rio Grande do Sul. AES manages Sul under a 30-year concession expiring in 2027.

Regulatory Framework — In Brazil, ANEEL, a government agency, sets the tariff for each distribution company based on a Return on Asset Base methodology, which also benchmarks operational costs against other distribution companies.

The tariff charged to regulated customers consists of two elements: (i) pass-through of non-manageable costs under a determined methodology ("Parcel A"), including energy purchase costs, sector charges and transmission and distribution system expenses; and (ii) a manageable cost component ("Parcel B"), including operation and maintenance costs (defined by ANEEL), recovery of investments and a component for a return to the distributor. The return to distributors is calculated as the net asset base multiplied by the Regulatory WACC, which is set for all industry participants during each tariff reset cycle. The current Regulatory WACC for Eletropaulo, after tax, is 8.1%. This WACC is effective for three years and as such will be updated again in the next tariff review for Sul in April 2018.

Each year ANEEL reviews each distributor's tariff for an annual tariff adjustment. The annual tariff adjustments allow for pass-through of Parcel A costs and inflation impacts on Parcel B costs, adjusted for expected efficiency gains and quality performances. Distribution companies are required to contract between 100% and 105% of anticipated energy needs through the regulated auction market. If contracted levels fall below required levels distribution companies may be subject to limitations on the pass-through treatment of energy purchase costs as well as penalties. As the costs incurred on energy purchases by our distribution companies are passed through to customers with adjustments on a yearly basis, working capital will be sensitive to significant increases in energy prices. In order to reduce potential working capital needs, in February 2015, ANEEL opened two public hearings (i) to discuss an Extraordinary Tariff Review ("ETR") requested by distribution companies and ii) to discuss adjustments to a tariff flag mechanism that may change the tariff to customers on a monthly basis depending on energy prices. These items were approved by ANEEL and made effective on March 2, 2015. The ETR represented an average tariff increase of 32% in AES Eletropaulo and 39% at AES Sul. The tariff flag mechanism, a temporary measure in response to higher energy prices due to dry hydrological conditions, was improved by incorporating i) a higher tariff increase depending on the energy purchase costs and (ii) resources collected by the tariff flag being centralized in an account and shared among distribution companies in proportion to their respective involuntary exposure. Most recently, ANEEL approved the Annual Readjustment for AES Sul on April 14, 2015 representing an average tariff increase of 5.46%.

Every four to five years, ANEEL resets each distributor's tariff to incorporate the revised Regulatory WACC and determination of the distributor's net asset base. Eletropaulo's tariff reset occurs every four years and the next tariff reset will be in July 2019. Sul's tariff is reset every five years and the next tariff reset is expected in April 2018. The 4th Tariff Reset for AES Eletropaulo occurred on July 4, 2015, representing an average tariff increase of 15.23%.

ANEEL challenged the parameters of a tariff reset for Eletropaulo implemented in July 2012 and retroactive to 2011. ANEEL asserted that during the period between 2007 and 2011, certain assets that were included in the regulatory asset base should not have been included and that Eletropaulo should refund customers for the return on the disputed assets earned during this period. On December 17, 2013, ANEEL determined, at the administrative level, that Eletropaulo should adjust the prior (2007-2011) regulatory asset base and refund customers in the amount of $269 million (R$630 million) over a period of up to four tariff processes beginning in July 2014. Eletropaulo filed for an administrative appeal requesting ANEEL to reconsider its decision and requested that the decision be suspended until the appeal process was completed. On January 28, 2014, ANEEL denied Eletropaulo's request to suspend the effects of the previous decision. On January 29, 2014, Eletropaulo requested and received from the Federal Court of Brazil an injunction for the suspension of the effects of ANEEL's previous decision. As ANEEL had confirmed the original decision and the related refund to customers, the injunction no longer became effective. The Company recognized a regulatory liability of approximately $269 million in the Company's 2013 fourth quarter results of operations since ANEEL had compelled the Company to refund customers. Eletropaulo started reimbursing customers in July 2014.

On December 18, 2014, the effects of the injunction were restored and on January 5, 2015, during a public hearing, ANEEL resolved to follow the legal decision. However, on January 7, 2015 ANEEL requested the suspension of the injunction. While the final legal decision has yet not been taken, ANEEL released a new tariff for Eletropaulo on January 8, 2015, not considering the reimbursement to customers, which is immediately effective. On June 30, 2015, ANEEL included in Eletropaulo's tariff reset the reimbursement of amounts previously refunded to customers from July 2014 through early January 2015. In addition to ANEEL's failure thus far to suspend the injunction through the appeals process in the Brazilian courts, the tariff reset resulted in management's reassessment of the probability of refunding customers these disputed amounts. The Company now considers it only reasonably possible that Eletropaulo will be required to refund these amounts to customers prior to the ultimate resolution of the pending court case. As a result, during the second quarter of 2015, the Company reversed the remaining regulatory liability for this contingency of $161 million. Eletropaulo believes it has meritorious arguments on this matter and will continue to pursue its objections to ANEEL's rulings vigorously, however there can be no assurance that Eletropaulo will prevail.

Key Financial Drivers — Through and beyond 2016, Eletropaulo's and Sul's financial results are likely to be driven by many factors including, but not limited to, the following:

- Hydrology, impacting quantity of energy sold and energy purchased
- Brazilian economic growth and tariff increases, impacting energy consumption growth, losses and delinquency (see Item 7.—Key Trends and Uncertainties—Macroeconomics—Brazil for further information)
- Ability of both Eletropaulo and Sul to pass through costs via productivity gains
- Capital structure optimization to reduce leverage and interest costs
- Sul's fourth tariff cycle outcomes in April 2018
- July 2012 regulatory asset base resolution
- The Eletrobrás case (see Item 3.—Legal Proceedings for further information)

Eletropaulo and Sul are affected by the demand for electricity, which is driven by economic activity, weather patterns and customers' consumption behavior. Operating performance is also driven by the quality of service, efficient management of operating and maintenance costs as well as the ability to control non-technical losses. Finally, annual tariff adjustments and periodic tariff resets by ANEEL impact results from operations.

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 3,239 MW and distribution networks serving 1.3 million customers as of December 31, 2015. MCAC operations accounted for the following proportions of consolidated AES Operating Margin, AES Adjusted PTC (a non-GAAP measure), AES Operating Cash Flow, and AES Proportional Free Cash Flow (a non-GAAP measure):

MCAC SBU [(1)]	2015		2014		2013	
% of AES Operating Margin	19	%	18	%	17	%
% of AES Adjusted PTC (a non-GAAP measure)	20	%	19	%	19	%
% of AES Operating Cash Flow	28	%	16	%	17	%
% of AES Proportional Free Cash Flow (a non-GAAP measure)	30	%	20	%	23	%

[(1)] Percentages reflect the contributions by our MCAC SBU before deductions for Corporate.

The following table provides highlights of our MCAC SBU operations:

Countries	Dominican Republic, El Salvador, Mexico, Panama and Puerto Rico
Generation Capacity	3,239 gross MW (2,482 proportional MW)
Generation Facilities	17 (including 1 under construction)
Key Generation Businesses	Andres, Panama and TEG TEP
Utilities Penetration	1.3 million customers (3,754 GWh)
Utility Businesses	4
Key Utility Businesses	El Salvador

The table below lists our MCAC SBU facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest (% Rounded)		Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Andres	Dominican Republic (DR)	Gas	319	90	%	2003	2018	Ede Este/Non-Regulated Users/Linea Clave
Itabo[(1)]	DR	Coal/Gas	295	45	%	2000	2016	Ede Este/Ede Sur/Ede Norte/Quitpe
DPP (Los Mina)	DR	Gas	236	90	%	1996	2016	Ede Este
Dominican Republic Subtotal			850					
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	55	%	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
Illumina	US-PR	Solar	24	100	%	2012		
Puerto Rico Subtotal			548					
MCAC Total			3,239					

(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 (% Rounded)		Expected Year of Commercial Operations
		Gas	122	90	%	1H 2017

DPP (Los Mina) Conversion	Dominican Republic	
Dominican Republic Subtotal		122
MCAC Total		122

MCAC Utilities — Our distribution businesses are located in El Salvador and distribute power to 1.3 million people in the country. These businesses consist of four companies, each of which operates in defined service areas as described below:

Business	Location	Approximate Number of Customers Served as of 12/31/2015	Approximate GWh Sold in 2015	AES Equity Interest (% Rounded)		Year Acquired
CAESS	El Salvador	583,000	2,174	75	%	2000
CLESA	El Salvador	377,000	892	80	%	1998
DEUSEM	El Salvador	76,000	132	74	%	2000
EEO	El Salvador	290,000	556	89	%	2000
		1,326,000	3,754			

The following map illustrates the location of our MCAC facilities:
MCAC Businesses
Dominican Republic
Business Description — AES Dominicana consists of three operating subsidiaries, Itabo, Andres and DPP. AES has 23% of the system capacity (850 MW) and supplies approximately 42% of energy demand through these generation facilities.
During 2014, AES entered into a strategic partnership with the Estrella and Linda Groups ("Estrella-Linda"), an investor group based in the Dominican Republic. Under this agreement, Estrella-Linda acquired an 8% non-controlling interest in AES' business in the Dominican Republic for $83 million and, in December 2015, exercised its first call option of additional 2% for$18 million, net of discount and transaction costs. Estrella-Linda has an additional option to increase up to 20% by the end of 2016. Estrella-Linda is a consortium of two leading Dominican industrial groups: Estrella and Grupo Linda. The two partners manage a diversified business portfolio, including construction services, cement, agribusiness, metalwork, plastics, textiles, paints, transportation, insurance and media.
Itabo is 45%-owned by AES, 5% by Estrella-Linda, 49.97% owned by FONPER, a government-owned utility and the remaining 0.03% is owned by employees. Itabo owns and operates two thermal power generation units with a total of 295 MW of installed capacity. Itabo's PPAs are with government-owned distribution companies and expire in 2016. Since the majority of distribution companies' long term PPAs are expiring in July 2016, the CDEEE is sponsoring a bidding process that is expected to be released and awarded during 2016 in order to secure supply and competitive pricing for actual and future distribution energy requirements. The existing business strategy is to secure approximately 75% to 85% of the open position through new PPAs with distribution companies and large users. Price and PPA structure will be subject to the terms of the bidding process.
Andres and DPP are owned 90% by AES and 10% by Estrella-Linda. Andres has a combined cycle gas turbine and generation capacity of 319 MW as well as the only LNG import facility in the country, with 160,000 cubic meters of storage capacity. DPP (Los Mina) has two open cycle natural gas turbines and generation capacity of 236 MW. Both Andres and DPP have in aggregate 555 MW of installed capacity, of which 450 MW is mostly contracted until 2018 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 the diversion of the cargoes 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.
In 2005, Andres entered into a contract to sell re-gasified LNG for further distribution to industrial users within the Dominican Republic using compression technology to transport it within the country. In January 2010, the first LNG truck

tanker loading terminal started operations. With this investment, AES is capturing demand from industrial and commercial customers.

Market Structure

Electricity Market — The Dominican Republic has one main interconnected system with approximately 3,742 MW of installed capacity, composed primarily of thermal generation (82%), hydroelectric power plants (16%) and wind plants (2%).

Natural Gas Market — The natural gas market in the Dominican Republic started developing in 2001 when AES entered into a long-term contract for LNG and constructed AES Dominicana's LNG regasification terminal.

Regulatory Framework — The regulatory framework in the Dominican Republic consists of a decentralized industry including generation, transmission and distribution, where generation companies can earn revenue through short- and long-term PPAs, ancillary services and a competitive wholesale generation market. All electric companies (generators, transmission and distributors), are subject to and regulated by the GEL.

Two main agencies are responsible for monitoring and ensuring compliance with the GEL, the CNE and the SIE. CNE is in charge of drafting and coordinating the legal framework and regulatory legislation, proposing and adopting policies and procedures to assure best practices, drafting plans to ensure the proper functioning and development of the energy sector and promoting investment. SIE's main responsibilities include monitoring and supervising compliance with legal provisions and rules, monitoring compliance with the technical procedures governing generation, transmission, distribution and commercialization of electricity and supervising electric market behavior in order to avoid monopolistic practices.

The electricity tariff applicable to regulated customers is subject to regulation within the concessions of the distribution companies. Clients with demand above 1.0 MW are classified as unregulated customers and their tariffs are unregulated.

Fuels and hydrocarbons are regulated by a specific law which establishes prices to end customers and a tax on consumption of fossil fuels. For natural gas there are regulations related to the procedures to be followed to grant licenses and concessions: i) distribution, including loading, transportation and compression plants; ii) the installation and operation of natural gas stations, including consumers and potential modifications of existing facilities; and iii) conversion equipment suppliers for vehicles. The regulation is administered by the ICM who supervises commercial and industrial activities in the Dominican Republic as well as the fuels and natural gas commercialization to the end users.

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

- Spot prices are mainly driven by the fluctuations in commodity prices due to the dependency of the Dominican Republic on oil-based thermal generation. Since the fuel component is a pass-through cost under the PPAs, any variation in the oil prices will mainly impact the spot sales for both Andres and Itabo, which are expected to be net sellers in the upcoming years. Current contracting level for 2016 is close to 90%. Supply shortages in the near term (next 2 to 3 years) may provide opportunities for upside but new generation is expected to come online from 2018.
- Additional sales derived from natural gas domestic demand are expected to continue providing an income stream and growth based on the entry of future projects and the fees from the infrastructure service.

In addition, the financial weakness of the three state-owned distribution companies due to low collection rates and high levels of non-technical losses has led to delays in payments for the electricity supplied by generators. At times when outstanding receivable balances have accumulated, AES Dominicana has accepted payment through other means, such as government bonds, in order to reduce the balance. There can be no guarantee that alternative collection methodologies will always be an avenue available for payment options.

Construction and Development — DPP is converting its existing plant from open cycle to combined cycle. The project will recycle DPP's heat emissions and increase total power output by approximately 114 MW of gross capacity at an estimated cost of $260 million, fully financed with non-recourse debt. The EPC contract was signed on July 2, 2014, and the additional capacity is expected to become operational in in the first half of 2017. Based on the increased capacity, AES Dominicana executed a PPA for 270 MW for a 6.5 years term beginning on August 1, 2016.

Panama

Business Description — AES owns and operates five hydroelectric plants and one thermoelectric power plant, Estrella del Mar I, which commenced operations in March 2015, representing 705 MW and 72 MW of hydro and thermal capacity respectively, for a total of 777 MW equivalent to 25% of the installed capacity in Panama. The majority of hydro sources in Panama are based on run-of-river technology, with the exception of the 260 MW Bayano plant.

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

Market Structure — Panama's current total installed capacity is 3,068 MW, of which 56% is hydroelectric, 3% wind and the remaining 41% thermal generation from diesel, bunker fuel and coal.
The Panamanian power sector is composed of three distinct operating business units: generation, distribution and transmission, all of which are governed by Electric Law 6 enacted in 1997.
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.
The CND implements the economic dispatch of electricity in the wholesale market. The CND's objectives are to minimize the total cost of generation and maintain the reliability and security of the electric power system, taking into account the price of water, which determines the dispatch of hydro plants with reservoirs. Short-term power prices are determined on an hourly basis by the last dispatched generating unit.
In Panama, dry hydrological conditions remained during 2015 affecting the generation output from hydroelectric facilities as in the prior year. AES Panama had to purchase energy on the spot market to fulfill its contract obligations as its generation output was below contract levels. The drop in the commodities prices helped to reduce the replacement cost and the financial impact of spot purchases compared to the prior year. Despite the hydrology conditions, spot prices were down to $90/MWh from $217/MWh in 2014, impacting also the amount recognized through the 2014-2016 Government Compensation Agreement to only $5.8 million out of the $30 million for 2015.
On March 31, 2014, the government of Panama agreed to reduce the financial impact of spot electricity purchases and transmission constraints equivalent to a 70 MW reduction in contracted capacity for the period 2014-2016 by compensating AES Panama for spot purchases up to $40 million in 2014, $30 million in 2015 and $30 million in 2016.
Regulatory Framework — 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 promote the procurement of electrical energy, hydrocarbons and alternative energy 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 and the transmission and distribution of natural gas utilities and the companies that provide such services.
Generators can only contract their firm capacity. Physical generation of energy is determined by the CND regardless of contractual arrangements.
Key Financial Drivers — Financial results are likely to be driven by many factors including, but not limited to, the following:

- Lower hydrology resulting in low generation and additional energy purchases to fulfill contracts, partially mitigated by additional generation from Estrella del Mar I, lower spot prices driven by the drop in commodities, and the compensation amount from the Government Compensation Agreement.
- In addition to spot prices being driven by hydrology since Panama is highly dependent on hydro generation (~56%), the fluctuations in commodity prices, mainly oil prices, affect the thermal generation cost impacting the spot prices and the opportunity cost of water. In the event of low hydrology, high commodity prices will increase the business exposure and the cost of replacement power to back up our contractual commitment.
- Constraints imposed by the capacity of the transmission line connecting the west side of the country with the load center are expected to continue until the end of 2016 keeping surplus power trapped, particularly during the wet season.
- Country demand as GDP growth is expected to remain strong over the short and medium term.

Given that most of AES' portfolio is run-of-river, hydrological conditions have an important influence on its profitability. Variations in actual hydrology can result in excess or a short energy balance relative to our contract obligations. During the low inflow period (January to May), generation tends to be lower and AES Panama may purchase energy in the short-term market to cover contractual obligations. During the remainder of the year (June to December), generation tends to be higher and energy generated in excess of contract volumes is sold to the short-term market. In addition to hydrological conditions, commodity prices affect short-term electricity prices. See Item 7.—Key

Trends and Uncertainties—Operational—Sensitivity to Dry Hydrological Conditions for further information.
Construction and Development — Continuing with the strategy to reduce reliance on hydrology started with the acquisition of the power barge, Estrella del Mar I, in August 2015 AES executed a partnership agreement with Deeplight Corporation, a minority partner, with the purpose 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, 2015, amounts capitalized include $7 million recorded in Construction in Progress and the project is scheduled to initiate operations in the first half of 2018.

Mexico
Business Description — AES has 1,055 MW of installed capacity in Mexico, including the 550 MW Termoeléctrica del Golfo ("TEG") and Termoeléctrica Peñoles ("TEP") facilities and Merida III ("Merida"), a 505 MW generation facility.
The TEG and TEP pet coke-fired plants, located in 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 fuel under a long-term contract, the cost of which is then passed through to CFE under the terms of the PPA.
In line with AES' strategy of building strategic partnerships, on January 18, 2016 the 50/50 Joint Venture partnership agreement with Grupo BAL was fully executed. The Joint Venture will co-invest in power and related infrastructure projects in Mexico.
Market Structure — Mexico has a single national electricity grid, the SEN, covering nearly all of Mexico's territory. Mexico has an installed capacity totaling 65 GW with a generation mix of 74% thermal, 19% hydroelectric and 7% other. Electricity consumption is split between the following end users: industrial (58%), residential (26%) and commercial and service (16%).
Regulatory Framework — Following the constitutional changes approved in December 2013, during 2014 and 2015 the Mexican government issued a package of secondary regulations, including the Electricity Law, and operational dispositions, with the objective to start the implementation of a new regulatory framework which foresees:

- The energy market liberalization in January 2016 through the implementation of: wholesale electricity market (day ahead and real time market), ancillary services, capacity, Clean Energy Certificates, and Financial Transmission Rights market.
- CFE's, former state-owned electric monopoly, vertical and horizontal disintegration into different segments of the value chain: generation, transmission, distribution and commercialization.
- CENACE 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.
- Implementation of annual mid and long term auctions to secure supply for the regulated demand, establishing a PPA with CFE as the Basic Supplier.

According to the new regulatory framework, new assets developed under the new framework or assets transferred to the new regime and in operation after the approval of the Electricity Law (August 2014) are eligible to participate in the new markets. Additionally, projects developed and operated under the Electric Public Service Law (self-supply framework) like TEG TEP, could choose to participate. Until the new framework is further analyzed, AES will continue operating under the same conditions. Merida III and TEG/TEP will continue providing power under long-term contracts and selling any excess or surplus energy produced to CFE.
Key Financial Drivers — Operational performance is the key business driver as the companies are fully contracted and better performance provides additional financial benefits including performance incentives and/or excess energy sales (in the case of TEG/TEP). The energy prices of TEG/TEP for the sales in excess over its long-term contracts are driven by the average production cost of CFE which is highly dependent on natural gas and oil. If the average production cost of CFE is higher than the cost of generating with pet coke, our businesses in Mexico will benefit provided that they are able to sell energy in excess of their PPAs.
Other MCAC Businesses
Puerto Rico
Business Description — AES Puerto Rico owns and operates a coal-fired cogeneration plant and a recently acquired 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, a state-owned entity that supplies virtually all of the electric power consumed in Puerto Rico and generates, transmits and distributes electricity to 1.4 million customers. On April 29, 2015, AES completed the acquisition of 100% of the common stock

of the solar plant, AES Illumina. Its results of operations have been included in AES' consolidated results of operations from the date of acquisition. See Item 7.—Key Trends and Uncertainties—Macroeconomic and Political—Puerto Rico for further discussion of the long-term PPA with PREPA. In addition, AES Puerto Rico has ongoing litigation regarding the disposal of ash in the Dominican Republic. See Item 3.—Legal Proceedings.

El Salvador

Business Description — AES is the majority owner of four of the five distribution companies operating in El Salvador. The distribution companies are operated by AES on an integrated basis under a single management team. AES El Salvador's territory covers 77% of the country. AES El Salvador accounted for 3,730 GWh of market energy purchases during 2015, or about 64% market share of the country's total energy purchases.

AES El Salvador also owns AES Nejapa, a 6 MW power plant generating electricity with methane gas from a landfill, fully contracted with CAESS. During 2015, AES El Salvador began operations of a AES Moncagua, a 2.5 MW solar facility located in the east of the country, which is fully contracted with EEO.

The sector is governed by the General Electricity Law and the general and specific orders are issued by Superintendencia General de Electricidad y Telecomunicacions ("SIGET" or "The Regulator"). The Regulator, jointly with the distribution companies in El Salvador, completed the tariff reset process in December 2012 and defined the tariff calculation to be applicable for the next five years (2013-2017).

Europe SBU

Our Europe SBU has generation facilities in five countries. Our European operations accounted for the following proportions of consolidated AES Operating Margin, AES Adjusted PTC (a non-GAAP measure), AES Operating Cash Flow, and AES Proportional Free Cash Flow (a non-GAAP measure):

Europe SBU [1]	2015		2014		2013	
% of AES Operating Margin	11	%	13	%	13	%
% of AES Adjusted PTC (a non-GAAP measure)	15	%	19	%	19	%
% of AES Operating Cash Flow	14	%	13	%	15	%
% of AES Proportional Free Cash Flow (a non-GAAP measure)	15	%	14	%	18	%

[1] Percentages reflect the contributions by our Europe SBU before deductions for Corporate.

The following table provides highlights of our Europe operations:

Countries	Bulgaria, Jordan, Kazakhstan, Netherlands and United Kingdom
Generation Capacity	6,781gross MW (5,009 proportional MW)
Generation Facilities	12
Key Generation Businesses	Maritza, Kilroot, Ballylumford, and Kazakhstan

Operating installed capacity of our Europe SBU totaled 6,781 MW. Presented in the table below is a list of our Europe SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest (% Rounded)		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					
Amman East	Jordan	Gas	380	37	%	2009	2033-2034	National Electric Power Company
IPP4	Jordan	Heavy Fuel Oil/Gas	247	60	%	2014	2039	National Electric Power Company
Jordan Subtotal			627					
Ust-Kamenogorsk CHP	Kazakhstan	Coal	1,372	100	%	1997	Short-term	Various
Shulbinsk HPP[(1)]	Kazakhstan	Hydro	702	—	%	1997	Short-term	Various
Ust-Kamenogorsk HPP[(1)]	Kazakhstan	Hydro	331	—	%	1997	Short-term	Various
Sogrinsk CHP	Kazakhstan	Coal	345	100	%	1997	Short-term	Various
Kazakhstan Subtotal			2,750					
Elsta[(2)]	Netherlands	Gas	630	50	%	1998	2018	Dow Benelux/Delta/Nutsbedrijven/ Essent Energy
Netherlands ES	Netherlands	Energy Storage	10	100	%	2015		
Netherlands Subtotal			640					
Ballylumford	United Kingdom	Gas	1,246	100	%	2010	2023	Power NI/Single Electricity Market (SEM)
Kilroot[(3)]	United Kingdom	Coal/Oil	662	99	%	1992		SEM
Kilroot ES	United Kingdom	Energy Storage	10	100	%	2015		
United Kingdom Subtotal			1,918					
Europe Total			6,781					

(1) AES operates these facilities under concession agreements until 2017.
(2) Unconsolidated entity, the results of operations of which are reflected in Equity in Earnings of Affiliates.
(3) Includes Kilroot Open Cycle Gas Turbine ("OCGT").

The following map illustrates the location of our European facilities:

Europe Businesses

Bulgaria

Business Description — Our Maritza plant is a 690 MW lignite fuel plant that was commissioned in June 2011. Maritza is fully compliant with the EU Industrial Emission Directive, which came into force in January 2016. Maritza's entire power output is contracted with NEK under a 15-year PPA expiring in 2026, capacity and energy based, with a fuel pass-though. The lignite and limestone are supplied under a 15-year fuel supply contract.

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.

Market Structure — The maximum market capacity in 2015 was approximately 13.6 GW. Thermal generation, which is mostly coal-fired, and nuclear power plants account for 64% of the installed capacity.

Regulatory Framework — The electricity sector in Bulgaria operates under the Energy Act of 2004 that allows the sale of electricity to take place freely at negotiated prices, at regulated prices between parties or on the organized market.

In 2015 the government of Bulgaria has made advances toward market liberalization and has engaged with the World Bank to develop a model for a fully liberalized electricity market in Bulgaria. The final report with recommendations from the World Bank is expected in May 2016. The Independent Bulgarian Energy Exchange started commercial operation of the power exchange on January 19, 2016 after successful test sessions were held in December 2015.

Our investments in Bulgaria rely on long-term PPAs with NEK, the state-owned electricity public supplier and energy trading company. NEK is facing some liquidity issues and has been delayed in making payments under the PPAs with Maritza and St. Nikola. In May and June 2014, SEWRC issued decisions precluding the ability of NEK to pass-through to the regulated market certain costs incurred by NEK pursuant to the PPA with Maritza, which impacted NEK's liquidity and its ability to make payments under the PPA. SEWRC also instructed NEK and Maritza to begin negotiating amendments to the PPA. Maritza has engaged in negotiations with NEK and other Bulgarian state bodies concerning these matters. In August 2015, the ninth amendment of Maritza's PPA was executed under which Maritza and NEK would reduce the capacity payment to Maritza under the PPA by 14% through the PPA Term, without impacting the energy price component. In exchange, NEK would pay Maritza its overdue receivables. The amendment will become effective upon full payment of the overdue receivables by NEK, which is expected in 2016.

In 2014 SEWRC announced that it has asked the DG Comp to review NEK's respective PPAs with Maritza and a separate generator pursuant to European state aid rules, and to suspend the PPAs pending the completion of that review. DG Comp has not contacted Maritza about the SEWRC's request to date.

In March 2015, changes to the Energy Act were enacted. Changes included a limitation on electricity purchases from co-generators at preferential prices, the allocation of the proceeds from the sale of state CO_2 allowances to NEK, and an increase in the Regulator's independence through appointment of its members by the Parliament rather than by the Council of Ministers. In July 2015, additional measures were voted by the Parliament to complement the first measures taken in March 2015. An Electricity Security Fund was created to help NEK meet its obligations with energy producers, financed with a 5% contribution from all energy producers on their energy revenues as well as with proceeds from the sale of state CO_2 allowances. Maritza is able to pass-through this additional contribution to NEK since it falls under a change in law provision under the PPA. Following the Energy Act amendments on July 31, 2015 the regulator approved new regulated prices that led to 0.11% decrease for household electricity prices and increased the non-household prices between 0% and 20% for the various segments. On November 1, 2015 the regulator decreased the non-household prices 2.5% on average as result of the falling gas prices. All these actions are expected to improve NEK's liquidity. At this time, it is difficult to predict the impact of the political conditions and regulatory changes on our businesses in Bulgaria.

Maritza has experienced ongoing delays in the collection of outstanding receivables from NEK. As of December 31, 2015, Maritza had an outstanding receivables balance of $351 million including $44 million of current receivables, $82 million of receivables overdue by less than 90 days and $225 million of receivables overdue by more than 90 days. See Key Trends and Uncertainties—Macroeconomics and Political—Bulgaria in Item 7.—Management's Discussion and Analysis to this Form 10-K for further information.

NEK has failed to maintain a minimum rating pursuant to the Government Support Letter issued in 2005. As a result, the PPA could be terminated at the discretion of Maritza and the lenders. See Item 1A.—Risk Factors—We may not be able to enter into long-term contracts, which reduce volatility in our results of operations. As a result of any of the foregoing events, we may face a loss of earnings and/or cash flows from the affected businesses (or be unable to exercise remedies for a breach of the PPA) and may have to provide loans or equity to support affected businesses or projects, restructure them, write down their value and/or face the possibility that these projects cannot continue

operations or provide returns consistent with our expectations, any of which could have a material impact on the Company.
Key Financial Drivers — Both businesses, Maritza and St. Nikola, operate under PPA contracts. For the duration of the PPA, the financial results are primarily driven by, but not limited to: the availability of the operating units; the level of wind resource for St. Nikola; and NEK's ability to meet the terms of the PPA contract.
United Kingdom
Business Description — AES' generation businesses in the United Kingdom operate in the Irish Single Electricity Market (SEM) for the businesses located in Northern Ireland (1,918 MW). During 2015, AES sold its interests in wind development pipelines of 115 MW in Scotland.

The Northern Ireland generation facilities consist of two plants within the Greater Belfast region. Our Kilroot plant is a 662 MW coal-fired plant with 10 MW of energy storage facility and our Ballylumford plant is a 1,246 MW gas-fired plant. These plants provide approximately 70% of the Northern Ireland installed capacity and 18% of the combined installed capacity for the island of Ireland.

Kilroot is a merchant plant that bids into the SEM market. Kilroot derives its value from the variable margin when scheduled in merit and the margin from constrained dispatch (when dispatched out of merit to support the system in relation to the wind generation, voltage and transmission constraints) and capacity payments paid through the SEM Capacity Payment Mechanism. In addition to the above, value is also secured from ancillary services.

Ballylumford is partially contracted for 600 MW under a PPA with PPB that expires in 2018, with an extension at the offtaker's option through 2023, with the remaining capacity bid into the SEM market. Ballylumford's key sources of revenue are availability payments received under the PPA and capacity payments offered through the SEM Capacity Payment Mechanism. Additionally, Ballylumford receives revenue from constrained dispatch through which the costs of operation are recovered from the market and also from the ancillary services market.

Market Structure — The majority of the generation capacity in the SEM is represented by gas-fired power plants, which results in market sensitivity to gas prices. Wind generation capacity represents approximately 18% of the total generation capacity. The governments of Northern Ireland and the Republic of Ireland plan further increases in renewables. Market availability and liquidity of hedging products are weak, reflecting the limited size and immaturity of the market, the predominance of vertical integration and lack of forward pricing. There are essentially three products (baseload, mid-merit and peaking) which are traded between the generators and suppliers.

Regulatory Framework — Electricity Regulation — The SEM is an energy market established in 2007 and is based on a gross mandatory pool within which all generators with a 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, there is 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 declared availability of a unit and have a degree of volatility to reflect seasonal influences, demand and the actual out-turn of generation declared available over each trading period.

Environmental Regulation — The European Commission adopted in 2011 the Industrial Emissions Directive ("IED") that establishes the Emission Limit Values ("ELV") for SO_2, NO_x and dust emissions to be complied with starting from January 1, 2016. Both Ballylumford and Kilroot are required to comply with the IED. The Ballylumford C Station is compliant without the need for investment. Both Ballylumford B Station and Kilroot required investment to be in compliance.

The IED provides for two options that may be implemented by the EU member states other than compliance with the new ELV's- the Transitional National Plan ("TNP") or Limited Life Time Derogation ("LLTD").

Kilroot has opted into the TNP and this allows the plant to operate between 2016-2020, being exempt from compliance with ELVs, but observing a ceiling set for maximum annual emissions that is based on the last 10 years average emissions and operating hours. Kilroot has invested approximately $10 million in Umbrella Selective Non Catalytic Reduction ("USNCR") technology, which reduces the plant's NO_x emissions enabling the plant to increase its capacity factor within the ceiling of NO_x emissions and earn energy margin. Further technical modifications are being evaluated which could make the plant fully compliant with IED from 2020.

Without investment, the Ballylumford B station of 540 MW would not meet the standards of the IED following 2015. In 2014, AES competed to secure a Local Reserve Services Agreement ("LRSA") with the Transmission System Operator ("TSO") to refurbish two of the three units to be compliant with ELVs under IED, providing at least 250 MW of capacity from 2016 to 2018 with an option to extend to 2020 by the TSO. These units will also qualify for capacity payments under the SEM.

Key Financial Drivers — For our businesses in the SEM market, the financial results will be driven by, but not limited to, the following, and may change in 2017 due to regulatory changes to the market structure and payment mechanism:

- Availability of the operating units

- Commodity prices (gas, coal and CO_2) and sufficient market liquidity to hedge prices in the short-term
- Electricity demand in the SEM

Kazakhstan

Business Description — Our businesses account for approximately 6% of the total annual generation in Kazakhstan. Of the total capacity of 2,750 MW, 1,033 MW is hydroelectric and operates under a concession agreement until the beginning of October 2017 and 1,717 MW of coal-fired capacity is owned outright. The thermal plants are designed to produce heat with electricity as a co- or by-product.

The Kazakhstan businesses act as merchant plants for electricity sales by entering into bilateral contracts directly with consumers for periods of generally no more than one year. There are no opportunities for the plants to be in contracted status, as there is no central offtaker, and the few businesses that could take a whole plant's generation tend to have in-house generation capacity. The 2015 amendments to the Electricity Law state that a centrally organized capacity market will be established by 2019, but the capacity offtaker still only signs annual contracts.
The hydroelectric plants are run-of-river and rely on river flow and precipitation, particularly snow. Due to the presence of a large multi-year storage dam upstream and a growing season minimum river flow rate agreement with Russia downstream, the plants are protected against significant downside risk to their volume in years with low precipitation. AES does not control water flow which impacts our generation.
Ust Kamenogorsk CHP provides heat to the city of Ust Kamenogorsk through the city heat network company (Ust Kamenogorsk Heat Nets). Ust Kamenogorsk CHP is their only source of supply.
Market Structure — The Kazakhstan electricity market totals approximately 20,657 MW, of which 17,421 MW is available. The bulk of the generating capacity in Kazakhstan is thermal with coal as the main fuel. As coal is abundantly available in Kazakhstan, most plants are designed to burn local coal. The geographical remoteness of Kazakhstan, in combination with its abundant resources, results in coal prices that are not reflective of world coal prices, current delivered cost is less than $18 per metric ton. In addition, the government closely monitors coal prices, due to their impact on the price of socially necessary heating and on electricity tariffs.
Regulatory Framework — All Kazakhstan generating companies sell electricity at or below their respective tariff-cap level. These tariff-cap levels have been fixed by the Kazakhstan government for the period 2009-2018 for each of the fifteen groups of generators. These groups were determined by the Ministry of Energy, previously Ministry of Industry and New Technologies, based on a number of factors including plant type and fuel used.
In July 2012, Kazakhstan enacted various amendments to its Electricity Law. Among the amendments was a requirement to reinvest all profits generated by electricity producers during the years 2013-2015. Accordingly, the business will be unable to pay dividends for the period 2013-2015. Under the amended Electricity Law, electricity producers must, on an annual basis, enter into Investment Obligation Agreements ("IOAs") with the Ministry of Energy. These annual IOAs must equal the sum of the upcoming year's planned depreciation and profit. Selection of investment projects for the IOAs is at the discretion of electricity producers, but the Ministry of Energy has the right to reject submitted IOA proposals. An electricity producer without an IOA executed by the Ministry of Energy may not charge tariffs exceeding its incremental cost of production, excluding depreciation. In December 2014, the Ministry of Energy executed IOAs with all four AES generators in Kazakhstan, which allow revenue at the tariff-cap level, but all generated cash will need to be reinvested.
In November 2015, Kazakhstan enacted amendments to its Electricity Law to extend price cap regulation till the end of
2018 and postpone the introduction of capacity market till 2019. In addition, the obligation for power plants to sign annual IOAs has been eliminated for 2016-2018. During 2013-2015, IOAs required businesses to reinvest the sum of all profits and depreciation on an annual basis, limiting the ability to send dividends. Beginning in 2016 Kazakhstan no longer has a restriction on sending dividends.
Heat production in Kazakhstan is also regulated as a natural monopoly. The heat tariffs are set on a cost-plus basis by making an application to the Regulator (Committee of Natural Monopoly Regulation and Competition Protection). Currently, tariffs are only for multi-year periods, but with some annual adjustments for fuel cost.
Key Financial Drivers — The financial results for assets in Kazakhstan are driven by many factors including, but not limited to: availability of the operating units; regulated electricity tariff-cap levels; regulated heat tariff levels; and weather conditions, but may change in 2016 due to regulatory changes to the market structure and payment mechanism.

- Availability of the operating units
- Regulated electricity tariff-cap levels
- Weather conditions
- Cost of coal

- Kazakhstan currency exchange rate fluctuation

Other Europe Businesses

In Jordan, AES has a 37% controlling interest in Amman East, a 380 MW (gross) oil/gas-fired plant fully contracted with the national utility under a 25-year PPA. We also have a 60% controlling interest in the IPP4 plant in Jordan, a 247 MW (gross)oil/gas-fired peaker plant which commenced operations in July 2014, fully contracted with the national utility under a 25-year PPA. As we have controlling interest in these businesses, we consolidate the results in our operations.

On July 2, 2014, the Company closed the sale of its 50% ownership interest in Silver Ridge Power ("SRP") for a purchase price of $179 million, excluding the Company's indirect ownership interests in SRP's solar generation businesses in Italy and Spain ("Solar Italy" and "Solar Spain," respectively). On February 9, 2015, SRP distributed its ownership interest in Solar Spain to a joint venture of AES and a third party. After this date, AES' only remaining economic interest under SRP ownership was in Solar Italy. The previous buyer of our interest in SRP also had an option to purchase the Company's indirect 50% interest in Solar Italy for an additional consideration of $42 million by August 2015. That buyer exercised its option to purchase Solar Italy on August 31, 2015, and the sale was completed on October 1, 2015. At this point, the Company ceased having continuing involvement not only with Solar Italy but also with SRP, its parent, and the Company recognized a gain of $5 million on the overall sale of SRP. On September 24, 2015, the Company completed the sale of Solar Spain, an equity method investment with 31 MW peak capacity. Net proceeds from the sale transaction were $31 million and the Company recognized a pretax gain on sale of less than $1 million.

Asia SBU

Our Asia SBU has generation facilities in four countries. Our Asia operations accounted for the following proportions of consolidated AES Operating Margin, AES Adjusted PTC (a non-GAAP measure), AES Operating Cash Flow, and AES Proportional Free Cash Flow (a non-GAAP measure):

Asia SBU [1]	2015		2014		2013	
% of AES Operating Margin	5	%	2	%	5	%
% of AES Adjusted PTC (a non-GAAP measure)	6	%	2	%	8	%
% of AES Operating Cash Flow	1	%	5	%	3	%
% of AES Proportional Free Cash Flow (a non-GAAP measure)	5	%	6	%	5	%

[1] Percentages reflect the contributions by our Asia SBU before deductions for Corporate.

The following table provides highlights of our Asia operations:

Countries	India, Philippines and Vietnam
Generation Capacity	2,290 gross MW (1,159 proportional MW)
Generation Facilities	5 (including 2 under construction)
Key Businesses	Masinloc, OPGC I and Mong Duong II

Operating installed capacity totals 2,290 MW. Presented below in the table is a list of our Asia SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest (% Rounded)		Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
OPGC[1]	India	Coal	420	49	%	1998	2026	GRID Corporation Ltd.
India Subtotal			420					
Masinloc	Philippines	Coal	630	51	%	2008	Mid and long-term	Various
Philippines Subtotal			630					
Mong Duong 2	Vietnam	Coal	1,240	51	%	2015	2040	EVN
Vietnam Subtotal			1,240					
Asia Total			2,290					

[1] Unconsolidated entity for which the results of operations are reflected in Equity in Earnings of Affiliates.

Under Construction

Business	Location	Fuel

			Gross MW	AES Equity Interest (% Rounded)		Expected Date of Commercial Operation
OPGC II	India	Coal	1,320	49	%	1H 2018
India Subtotal			1,320			
Masinloc ES	Philippines	Energy Storage	10	100	%	1H 2016
Philippines Subtotal			10			
Asia Total			1,330			

The following map illustrates the location of our Asia facilities:
Asia Businesses
India
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. The PPA is composed of a capacity payment based on fixed parameters and a variable component, including a pass-through of actual fuel costs. OPGC is an unconsolidated entity and results are reported as Equity in Earnings of Affiliates in our consolidated results of operations.
Construction and Development — As noted above, AES has one coal-fired project under development with a total capacity of 1,320 MW which is an expansion of our existing OPGC business. The project started construction in April 2014 and is currently expected to begin operations in 2018. As of December 31, 2015, total capitalized costs at the project level were $336 million (AES share of $165 million), while at the AES level capitalized costs were $13.6 million. Currently, 50% of the expansion capacity is contracted with the state offtaker, GRIDCO, for a period of 25 years, with a normative after-tax rate of return of 15.5% with an opportunity to capture additional 0.5% tied to timely completion of the project. The contract is subject to Central Electricity Regulatory Commission ("CERC") approval, which is responsible for publishing tariff determination norms every five years. The rest of the capacity is expected to be sold through competitive bid or regulated Power Purchase Agreements and a small component in the Indian merchant market.
In August 2014, the Supreme Court of India invalidated the allocation of captive coal blocks. The government of India has subsequently enacted new laws allowing coal block allocation to companies with limited levels of private ownership, based on which the coal blocks have been allocated to a subsidiary of OPGC, Odisha Coal and Power Ltd. ("OCPL"), which is an OPGC joint venture with another company wholly-owned by the government of Odisha. This new company meets the lower private ownership stipulations for allocation of mines.
Environmental Regulation — The Ministry of Environment Forest and Climate Change in India has recently amended the Environment (Protection) Rules with stricter emission limits for new as well as existing thermal power plants via their notification dated December 7, 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. An FGD system needs to be installed in the existing units of OPGC for complying with SO_2 emissions requirements. The business is evaluating the options and the cost implications. The required design modification and scheduled implications for the expansion project are currently being evaluated. The impacts of these amendments are still under review, but we believe the cost of complying with the new environmental regulations will be a pass-through in the GRIDCO tariff for both existing and expansion units. Ministry of Power has issued revised Tariff Policy in January 2016 to bring more regulatory certainty, attract private investment, ensure distribution efficiency and promote renewable energy.
Philippines
Business Description — The Masinloc power project in the Philippines is a 630 (gross) MW coal-fired plant located in Zambales, Philippines and is interconnected to the Luzon Grid. AES acquired 92% of Masinloc in 2008 (IFC is an 8% non-controlling shareholder in Masinloc). In July 2014, AES reduced its ownership to 51% through a sale to the EGCO Group, a Thailand-based power company. More than 95% of Masinloc's peak capacity and variable margin are contracted through

medium to long-term bilateral contracts primarily with Meralco, the largest distribution company in the Philippines, several electric cooperatives and industrial customers.

In January 2013, Masinloc entered into a new Power Supply Agreement ("PSA") with its main customer, Meralco, as the previous Transition Supply Contract ("TSA") expired in December 2012. The PSA is for 7 years, with an additional 3-year extension clause dependent on mutual agreement. Payments are primarily capacity-based. The PSA is primarily priced in U.S. Dollars, aligning the revenues with the majority of variable and fixed costs (fuel, debt, insurance) and minimizing currency exchange risks. Masinloc's remaining contracts expire between 2016 and 2026.

Construction and Development — In December 2015, financial close was achieved for 335 MW (gross) expansion unit adjacent to the existing 630 MW plant. The project, which will employ supercritical technology is expected to be commercially operating in 2019. The additional capacity is targeted for sale to distribution utilities, electric cooperatives, and industrial and commercial customers in the Luzon and Visayas grids. 40% of this additional capacity has already been contracted with an expectation to have 80% capacity contracted by the date of commercial operations.

Market Structure — The Philippine power market is divided into three grids representing the country's three major island groups — Luzon, Visayas and Mindanao. Luzon (which includes Manila and is the country's largest island) has limited interconnection with Visayas and represents 85% of the total demand of both regions. Luzon and Visayas together have an installed capacity of 16,093 MW.

There is diversity in the mix of the Luzon — Visayas generation, with coal accounting for 37%, natural gas for 17%, hydroelectric for 15%, geothermal generation for 10%, and the remaining 21% from other generating plants such as oil, wind, biomass, and solar (priority dispatch with feed-in tariff).

The primary customers for electricity are private distribution utilities, electric cooperatives, and large contestable (industrial and commercial) customers. Approximately 90%-94% of the system's total energy requirement is currently being sold/purchased through medium (3-5 years) to long (6-10 years) term bilateral contracts. The remaining 6%-10% of energy is sold through the WESM, which is the real-time, bid-based and hourly market for energy where the sellers and the buyers adjust their differences between their production/demand and their contractual commitments.

Environmental Regulation — The Renewable Energy Act of 2008 was enacted to promote the development, utilization and commercialization of renewable energy resources, such as solar, wind, small hydroelectric and biomass energies. Under Chapter III, Section 6, the Renewable Portfolio Standard (RPS) was introduced mandating all stakeholders in the electric power industry to contribute to the growth of the renewable energy industry of the country. Under the current draft of the RPS, certain customers (e.g. distribution utilities and retail electricity suppliers) will be required to source a certain percentage of their supply from eligible renewable energy sources. The National Renewable Energy Board ("NREB") is currently developing and implementing regulations for the RPS, including mechanisms for compliance by actual purchase of renewable energy or equivalent renewable energy certificates. If the regulations are implemented, our Retail Electricity Supply business in the Philippines could be affected by the RPS requirement.

Regulatory Framework

Electricity Regulation — The Philippines has divided its power sector into generation, transmission, distribution and supply under the EPIRA act. The EPIRA primarily aims to increase private sector participation in the power sector and to privatize the Philippine government's generation and transmission assets. Generation and supply are open and competitive sectors, while transmission and distribution are regulated sectors. Sale of power is conducted primarily through medium or long-term bilateral contracts between generation companies and distribution utilities specifying the volume, price and conditions for the sale of energy and capacity, which are approved by the ERC. Power is traded in the WESM which operates under a gross pool, central dispatch and net settlement protocols. Parties to bilateral contracts settle their transactions outside of the WESM and distribution companies or electricity cooperatives buy their imbalance (i.e., power requirements not covered by bilateral contracts) from the WESM. Distribution utilities and electric cooperatives are allowed to pass on to their end-users the bilateral contract rates, including WESM purchases, approved by the ERC.

Other Regulatory Considerations — Pursuant to EPIRA, RCOA commenced on June 26, 2013, under which retail electricity suppliers, who are duly licensed by the ERC, may supply directly to contestable customers (end-users with an average demand of at least 1 MW), with distribution companies or electricity cooperatives providing non-discriminatory wire services. Bilateral contracts with contestable customers do not require ERC approval to be implemented. Masinloc has obtained a retail electricity supplier license from the ERC and currently markets power to contestable customers. On June 16, 2015, ERC released a draft for the rules on mandatory contestability. According to this draft, all contestable customers with an average peak demand of more 750 kW are mandated to enter into power supply contracts by June 2016, at which point contestable customers shall be required to purchase power from licensed generation or retail suppliers instead of their local distribution utility.

Vietnam

Business Description — The Mong Duong II power project is a 1,240 MW gross coal-fired plant located in Quang Ninh Province of Vietnam and was constructed under a BOT contract (the project will be transferred to Vietnamese government after 25 years). AES-VCM Mong Duong Power Company Limited ("the BOT Company") is a limited liability joint venture owned by affiliates of AES (51%), Posco Energy Corporation (30%) and China Investment Corporation (19%). This is the first and largest coal-fired BOT project using pulverized coal fired boiler technology in Vietnam. The BOT Company has entered a PPA with EVN, the national utility, and a Coal Supply Agreement ("CSA") with Vinacomin, a state owned entity, both with a 25 year term starting from Commercial Operation Date. Since April 22, 2015, both units of the Power Facility have been in commercial operations, six months earlier than the committed schedule with the Vietnamese government. The BOT Company makes available the dependable capacity and delivers electrical energy to EVN and, in return, EVN makes payments to the BOT Company.

Market Structure — The Vietnam Power market is divided into three regions (North, Central and South), with current total installed capacity of 37,604 MW, an 11% increase from 2014 (33,970 MW). The total demand in year 2015 was 141.8 billion kWh with the highest demand of 70 billion kWh in the South and 60 billion kWh in the North.

The fuel mix in Vietnam is comprised of hydropower 35% (priority dispatch with low tariff), coal 35%, gas 20%, diesel and small hydro generation 5%, oil 1% (dispatched during emergencies or during peak demand), thermo-gas 1% and the remaining 3% imported from China and Lao. The government has a plan to increase thermal power capacity, primarily with coal, to reduce the dependence on hydroelectricity. According to the Master Plan VII, the total targeted installed capacity for 2020 is approximately 75,000 MW, in which coal-fired power will account for 48%, hydropower 23%, pumped storage hydropower 2%, gas-fired thermo-power 17%, renewable energy 6%, nuclear power 1% and imported power 3%.

EVN owns 58% of installed generation capacity followed by Petro Vietnam ("PVN") 12%, Vinacomin 4%, BOT projects 8% and others 18%. EVN is a state-owned company that is solely in charge of buying and selling electricity all over Vietnam. The government is planning to decrease EVN's ownership and increase private sector participation in the power market.

Regulatory Framework

Electricity Regulation — The electricity sector is overseen by several key government entities, including the National Assembly, the Prime Minister, the Ministry of Industry & Trade ("MOIT") and the Electricity Regulatory Agency of Vietnam ("ERAV"), which is under the supervision of the MOIT. These entities are responsible for the issuance of laws, guidance, and implementing regulations for the sector. The MOIT, in particular, is responsible for formulating a program to restructure the power industry, develop the electricity market and promulgating electricity market regulations.

Generation, transmission and distribution are currently dominated by the EVN, despite recent inclusion of other players. Transmission and distribution companies are wholly-owned by EVN and it also owns 58% of the total installed capacity as noted above. The fuel supply is owned by the government through Vinacomin and PVN. The government plans to equitize EVN-owned generation companies and separate generation, System and Market Provider ("SMP") and distribution into three different independent operations in order to establish the competitive power market.

Other Regulatory Considerations — According to Decision 63/2013/QĐ-TTG dated November 8, 2013, the roadmap of the power market of Vietnam consists of three phases. The first phase in relation to establishment of a competitive electricity market was finished at the end of 2014. The second phase: (i) period of 2015-2016 for establishment of a pilot competitive wholesale electricity market; and (ii) period of 2017-2021 for implementation of a competitive wholesale electricity market. The third phase: (i) period of 2022-2023 for establishment of a pilot competitive retail electricity market; and (ii) from 2013 onward for implementation of competitive retail electricity market. EVN as a long standing monopoly in the whole chain of generation, transmission and distribution, is being restructured to allow spin-off of several subsidiaries into either independent state-owned enterprises or joint stock companies. The 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.

Environmental Regulation — Mong Duong II BOT Power Plant complies strictly with environmental requirements involving local regulations and IFC Environmental, Health and Safety Guidelines for Thermal Power Plants.
The revised Environmental Act was enacted, effective from January 1, 2015 establishing new rules in relation to, discarded materials and hazardous waste management. Additionally, new regulations on the registration of effluent and emission waste will be put into effect from the beginning of 2018 with no material impact to AES.
According to Decision No. 1696/QĐ-TTG dated September 23, 2014 on re-using of ash and gypsum discharged from coal power plants for construction material, the power plants need to propose investment and construction plans (or co-operative investment) to convert ash into construction material before 2020. There is no material impact to AES.

Sri Lanka

Business Description — AES closed the sale of Kelanitissa, a 168 MW oil-fired business with 90% ownership, on January 27, 2016 with proceeds of $18 million, with the potential to receive up to an additional $1.3 million overdue receivable from CEB.

Financial Data by Country

See the table with our consolidated operations for each of the three years ended December 31, 2015, 2014 and 2013, and property, plant and equipment as of December 31, 2015 and 2014, by country, in Note 17—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 CFB 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 and its subsidiaries 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 — The CSAPR requires significant reductions in SO_2 and NO_X emissions from power plants in many states in which subsidiaries of the Company operate. Once fully implemented, the rule requires SO_2 emission reductions of 73%, and NO_X reductions of 54%, from 2005 levels. 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 CSAPR contemplates limited interstate and unlimited intra-state trading of emissions allowances by covered sources. Initially, the EPA issued emissions allowances to affected power plants based on state emissions budgets established by the EPA under the CSAPR. The Company is required to comply with the CSAPR in several states, including Ohio, Indiana, Oklahoma and Maryland. The Company complies with CSAPR through operation of existing controls and purchases of allowances on the open market, as needed. While the Company's 2015 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.

The EPA issued an interim final rule establishing the following deadlines for implementation of the CSAPR:

- January 1, 2015: Phase 1 (2015 and 2016) began for annual trading programs. Existing units must have begun monitoring and reporting SO_2 and NO_x emissions.
- May 1, 2015: Phase 1 began for ozone-season NO_x trading program. Existing units must have begun monitoring and reporting NO_x emissions.
- December 1, 2015 (and each Dec. 1 thereafter): Date by which sources must demonstrate compliance with ozone-season NO_x trading program (i.e., allowance transfer deadline).

- March 1, 2016 (and each March 1 thereafter): Date by which sources must demonstrate compliance with annual trading programs (i.e., allowance transfer deadline).
- January 1, 2017: Phase 2 (2017 and beyond) begins for annual trading programs. Assurance provisions in effect.
- May 1, 2017: Phase 2 (2017 and beyond) begins for ozone-season NO_x trading program. Assurance provisions in effect.

The EPA has released a proposed rule that would further reduce the amount of ozone season NO_X allowances that would be available under the market-based program, starting in 2017. This proposed rule would not affect annual SO_2 and NO_X allowances. We cannot predict at this time the impact that implementation of the revised CSAPR will have on the Company. Certain of the Company's subsidiaries could be required to increase their capital expenditures, make operational changes or purchase additional allowances on the open market resulting in additional compliance costs to fully comply with the CSAPR, which expenditures and costs could be material.

MATS — Pursuant to Section 112 of the CAA, the EPA published a final rule in 2012 called the MATS establishing National Emissions Standards for Hazardous Air Pollutants from coal and oil-fired electric utility steam generating units. The rule required all coal-fired power plants to comply with the applicable MATS standards by April 2015, with the possibility of obtaining a one year extension, if needed, to complete the installation of necessary controls. To comply with the rule, many coal-fired power plants may need to install additional control technology to control acid gases, mercury or PM, or they may need to repower with an alternate fuel or retire operations. Most of the Company's U.S. coal-fired plants operated by the Company's subsidiaries comply with MATS as of April 16, 2015 using existing control technologies. However, in some cases additional time for compliance was needed in order to make necessary capital and operational changes, particularly for older facilities lacking advanced control technologies. For a discussion of the deactivation and planned deactivation of certain units owned or partially owned by IPL and DP&L as a result of existing and expected environmental regulations, including MATS, see Unit Retirement and Replacement Generation below.

IPL required additional time for compliance beyond April 16, 2015. In December 2012, IDEM granted an extension to April 16, 2016 covering all coal-fired units at Harding Street and Eagle Valley, in addition to Unit 3 and Unit 4 at Petersburg. In February 2013, IDEM granted a three-month extension on Petersburg Unit 2 to July 16, 2015, and that unit, as well as Petersburg Unit 1, which did not receive an extension, is currently in compliance with MATS.

On August 14, 2013, the IURC approved IPL's MATS plan, which included investing up to $511 million in the installation of new pollution control equipment on IPL's five largest base load generating units. These coal-fired units are located at IPL's Petersburg and Harding Street generating stations. The IURC also approved IPL's request to recover operating and construction costs for this equipment (including a return) through a rate adjustment mechanism, with certain stipulations. IPL plans to spend a total of $454 million for this project as approximately $57 million of costs will largely be avoided as a result of the approval for IPL's plans to refuel Harding Street Station Unit 7 from coal to natural gas.

Several lawsuits challenging the MATS rule were filed by other parties and consolidated into a single proceeding before the United States Court of Appeals for the District of Columbia Circuit (the "D.C Circuit"). On April 15, 2014, the D.C. Circuit denied the challenges. On June 29, 2015, the U.S. Supreme Court reversed the D.C. Circuit's decision, and remanded MATS to the D.C. Circuit for further proceedings. On December 15, 2015, the D.C. Circuit issued an order remanding MATS to the EPA without vacatur while the EPA works to comply with the U.S. Supreme Court's decision. The EPA published its revised appropriate and necessary finding on December 1, 2015 and plans to finalize it by April 15, 2016. Further proceedings are expected; however, in the meantime MATS remains in effect. We currently cannot predict the outcome of this litigation, or its impact, if any, on our MATS compliance planning or ultimate costs.

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.

DP&L's Stuart Station and Hutchings Station have received NOVs from the EPA alleging that certain activities undertaken in the past are outside the scope of the RMRR exclusion. Additionally, generation units partially owned by DP&L 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 DP&L-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" towards 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.

EPA previously determined that states included in the CSAPR would not be required to make source-specific BART determinations for BART-affected electric generating units, reasoning that the emissions reductions required by the CSAPR were "better than BART." Concurrently, EPA also finalized a limited disapproval of certain states' plans — including Ohio's — that previously relied on the EPA's Clean Air Interstate Rule to improve visibility and substituted a Federal Implementation Plan that relies on the CSAPR. Environmental groups have challenged EPA's determination than the CSAPR is "better than BART." The challenge currently is proceeding in the D.C. Circuit.

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 regain 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 expected compliance date for these requirements is January 1, 2017. No impact is expected for Eagle Valley or Harding Street Generating Stations because these facilities will cease coal combustion prior to the compliance date. It is expected that improvements to the existing FGDs at Petersburg will be required in order to comply. IPL has engaged an engineering firm to further assess potential compliance measures and associated costs and timing. While costs associated with the proposed rule cannot accurately be predicted at this time, they could be material.

Greenhouse Gas Emissions — In January 2011, the EPA began regulating GHG emissions from certain stationary sources under the so-called "Tailoring Rule." The regulations are being implemented pursuant to two CAA programs: the Title V Operating Permit program and the program requiring a permit if undergoing certain new construction or major modifications, known as the Prevention of Significant Deterioration ("PSD"). Obligations relating to Title V permits include record-keeping and monitoring requirements. Sources subject to PSD can be required to implement BACT. In June 2014, the U.S. Supreme Court ruled that the EPA had exceeded its statutory authority in issuing the Tailoring Rule by regulating under the PSD program sources based solely on their GHG emissions. However, the U.S. Supreme Court also held that the EPA could impose GHG BACT requirements for sources already required to implement PSD for certain other pollutants. Therefore, if future modifications to our U.S.-based businesses' sources require PSD review 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 new source performance standards ("NSPS") for modified and reconstructed units (see below) that will serve as a floor (maximum emission rate) for future BACT requirements. Individual states are now required to 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 new source performance standards ("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 NGCC 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 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 Clean Power Plan (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 will 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 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. As a result, the D.C. Circuit may issue an opinion on these challenges prior to the end of 2016. On February 9, 2016, the U.S. Supreme Court issued orders staying implementation of the CPP pending resolution of challenges to the rule.

Because we likely will not know the answers to the above questions regarding the CPP until 2018 or later, because the first compliance period will not end until 2025, and because we cannot predict whether the CPP will survive the legal challenges, 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 Best Technology Available ("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 to comply with the California State Water Resources Board's regulations will see all once-through-cooled generating units retired from service by December 31, 2020. 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. The execution of the Implementation Plan is entirely dependent on the Company's ability to execute on long-term power purchase agreements to support project financing of the replacement units. The SWRCB is currently reviewing the Implementation Plan and latest update information to evaluate the impact on electrical system reliability. Power purchase agreements for the new generating capacity are currently under review by the California Public Utilities Commission.

Power plants will be 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 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 — 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 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 determines whether it has 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. We cannot predict the duration of the nationwide or partial stay of the rule or the outcome of this litigation; however, if the rule ultimately survives the legal challenges, it could have a material impact on our business, financial condition or results of operations.

On January 7, 2013, the Ohio Environmental Protection Agency issued an NPDES permit for J.M. Stuart Station. The primary issues involve the temperature and thermal discharges from the Station including the point at which the water quality standards are applied, i.e., whether water quality standards apply at the point where the Station discharge canal discharges into the Ohio River, or whether, as the EPA alleges, the discharge canal is an extension of Little Three Mile Creek and the water quality standards apply at the point where water enters the discharge canal. In addition, there are a number of other water-related permit requirements established with respect to metals and other materials contained in the discharges from the Station. The NPDES permit establishes interim standards related to the thermal discharge for 54 months that are comparable to current levels of discharge by Stuart Station. Permanent standards for both temperature and overall thermal discharges are established as of 55 months after the permit is effective, except that an additional transitional period of approximately 22 months is allowed if compliance with the permanent standards is to be achieved through a plan of construction and various milestones on the construction schedule are met. It is believed that compliance with the permit as written will require capital expenses that will be material to DP&L. The cost of compliance and the timing of such costs is uncertain and may vary considerably depending on a compliance plan that would need to be developed, the type of capital projects that may be necessary, and the uncertainties that may arise in the likely event that permits and approvals from other governmental entities would likely be required to construct and operate any such capital project. DP&L has appealed various aspects of the final permit to the Environmental Review Appeals Commission and a hearing has been scheduled for March 2016. The compliance schedule in the final permit has been modified to accommodate the timing of the hearing. The outcome of such appeal is uncertain.

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. NPDES permits regulate specific industrial wastewater and storm water discharges to the waters of Indiana under Sections 402 and 405 of the U.S. Clean Water Act. 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. IPL received an extension to the compliance deadline through September 29, 2017 for IPL's Harding Street and Petersburg facilities through agreed orders with IDEM. IPL conducted studies to determine the operational changes and control equipment necessary to comply with the new limitations. In October 2014, IPL filed its wastewater compliance plans for its power plants with the IURC. On July 29, 2015, the IURC approved a Certificate of Public Convenience and Necessity to convert Unit 7 at the Harding Street Station from coal-fired to natural gas-fired (about 410 MW net capacity), and also to install and operate wastewater treatment technologies at Harding Street Station and Petersburg Generation Station. IPL plans to invest $319 million in these projects to ensure compliance with the wastewater treatment requirements by September 29, 2017.

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. Compliance time lines for existing sources will be established by the applicable permitting authorities and will be set as soon as determined possible, but no sooner than November 1, 2018 and no later than December 31,

2023. Challenges to this rule are being consolidated in the U.S. Court of Appeals for the Fifth Circuit. IPL expects to recover through its environmental rate adjustment mechanism any operating or capital expenditures related to compliance with the effluent limitations requirements. Recovery of these costs is sought through an Indiana statute that allows for 80% recovery of qualifying costs through a rate adjustment mechanism with the remainder recorded as a regulatory asset to be considered for recovery in the next base rate case proceeding; however, there can be no assurances that IPL will be successful in that regard. In light of the uncertainties at this time, we cannot predict the impact of these regulations on our consolidated results of operations, cash flows, or financial condition, but it could be material.

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 CCR, oil, scrap metal, rubbish, small quantities of industrial hazardous wastes such as spent solvents, tree and land clearing wastes and PCB 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 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. The Company's U.S. subsidiaries are still analyzing the potential impact and compliance cost associated with this final rule, and there can be no assurance that the Company's businesses, financial condition or results of operations would not be materially and adversely affected by such rule.
Senate Bill 251 — In May 2011, Senate Bill 251 became a law in the state of Indiana. Senate Bill 251 is a comprehensive bill that, among other things, provides Indiana utilities, including IPL, with a means for recovering 80% of costs incurred to comply with federal mandates through a periodic retail rate adjustment mechanism. This includes costs to comply with regulations from the EPA, FERC, the North American Electric Reliability Corporation, Department of Energy, etc., including capital intensive requirements and/or proposals described herein, such as cooling water intake regulations, waste management and coal combustion byproducts, wastewater effluent, MISO transmission expansion costs and polychlorinated biphenyls. It does not change existing legislation that allows for 100% recovery of clean coal technology designed to reduce air pollutants.
Some of the most important features of Senate Bill 251 to IPL are as follows. Any energy utility in Indiana seeking to recover federally mandated costs incurred in connection with a compliance project shall apply to the IURC for a CPCN for the compliance project. It presents certain factors that the IURC must consider in determining whether to grant a CPCN. It further specifies that if the IURC approves a proposed compliance project and the projected federally mandated costs associated with the project, the following apply: (i) 80% of the approved costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism; (ii) 20% of the approved costs shall be deferred and recovered by the energy utility as part of the next general rate case filed with the IURC; and (iii) actual costs exceeding the projected federally mandated costs of the approved compliance project by more than 25% shall require specific justification and approval before being authorized in the energy utility's next general rate case. Senate Bill 251 also requires the IURC to adopt rules to establish a voluntary clean energy portfolio standard program. Such program will provide incentives to participating electricity suppliers to obtain specified percentages of electricity from clean energy sources in accordance with clean portfolio standard goals, including requiring at least 50% of the clean energy to originate from Indiana suppliers. The goals can also be met by purchasing clean energy credits.
CERCLA — The Comprehensive Environmental Response, Compensation and Liability Act of 1980 (aka "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 ("PRPs") 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 PRP at the Tremont City landfill Superfund site. 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 the second quarter of 2013, IPL retired in place five oil-fired peaking units with an average life of approximately 61 years (approximately 168 MW net capacity in total), as such units were not equipped with the advanced environmental control technologies needed to comply with existing and expected environmental regulations. Although these units represented approximately 5% of IPL's generating capacity, they were seldom dispatched by Midcontinent Independent System Operator, Inc. in recent years due to their relatively higher production cost and in some instances repairs were needed. In addition to these recently retired units, IPL has several other generating units that it expects to retire or refuel by 2017. These units are primarily coal-fired and represent 472 MW of net capacity in total. To replace this generation, in April 2013, IPL filed a petition and case-in-chief with the IURC in April 2013 seeking a CPCN to build a 550 to 725 MW CCGT at its Eagle Valley Station site in Indiana and to refuel Harding Street Station Units 5 and 6 from coal to natural gas (106 MW net

capacity each). In May 2014, the IURC issued an order on the CPCN authorizing the refueling project and granting approval to build a 644 to 685 MW CCGT at a total budget of $649 million. The current estimated cost of these projects is $632 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 until such time that we are allowed to collect both a return and depreciation expense on the CCGT and refueling project. The CCGT is expected to be placed into service in April 2017, and the refueling project was completed in December 2015. The costs to build and operate the CCGT and for 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 the assets have been placed in service.

As a result of existing and expected environmental regulations, including MATS, DP&L notified PJM of its plan to retire the six coal-fired units aggregating approximately 360 MW at its wholly-owned Hutchings Generation Station. Hutchings Unit 4 was retired in June 2013. In conjunction with administrative agreements reached in 2013 with the EPA and Ohio's Regional

Air Pollution Control Authority that resolved alleged violations of air quality standards, DP&L accelerated its plans with respect to Hutchings Units 1, 2, 3, 5 and 6 and those units were each retired by June 2015. DP&L removed equipment from such units so that combustion of coal was not possible after September 2013. Conversion of the coal-fired units to natural gas was investigated, but the cost of investment exceeded the expected return. In addition, DP&L owned approximately 207 MW of coal-fired generation at Beckjord Unit 6, which was operated by Duke Energy Ohio. Beckjord Unit 6 was retired effective October 1, 2014. At this time, DP&L does not have plans to replace the units that have been or will be retired.

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 2015 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.

Employees — As of December 31, 2015, we employed approximately 21,000 people.

Executive Officers — The following individuals are our executive officers:

Michael Chilton, 56 years old, was named Senior Vice President, Construction & Engineering, for the Company in December 2014. Prior to his current role, Mr. Chilton was the Managing Director of Construction from 2009 to 2011 and Vice President, Operations Support from 2012 to 2014. Before joining AES, Mr. Chilton held various leadership roles in Kennametal and GE, including: Regional Director for Kennametal Asia (2006-2009), with GE as President & CEO of Xinhua Controls Solutions based in China (2005-2006), Managing Director for Contractual Services Asia based in Singapore (2001-2005), Quality Leader for Energy Services based in Atlanta (1999-2001), Master Black Belt for Energy Sales based in Tokyo (1998-1999) and President of Joint Conversion company in Nuclear Energy based in Wilmington (1995-1998). Mr. Chilton has a BS in Chemical Engineering from University of Missouri, a MBA from University of Arkansas and a JD from Kaplan University.

Bernerd Da Santos, 52 years old, was appointed Chief Operating Officer and Senior Vice President in December 2014. Previously, Mr. Da Santos held several positions at the Company including 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 a member of the Board of Directors of Companhia Brasiliana de Energia, AES Tietê, AES Eletropaulo, AES Gener, Companhia de Alumbrado Electrico de San Salvador ("CAESS"), Empresa Electrica de Oriente ("EEO"), Companhia de Alumbrado Electrico de Santa Ana, AES Chivor & Cia S.C.A. E.S.P. 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.

Andrés R. Gluski, 58 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 Executive Vice President ("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. Mr. Gluski currently serves on President Obama's Export Council, the US-Brazil CEO Forum and the US-India CEO Forum. He is a member of the Board of Waste Management, and is Chairman of AES Gener in Chile and AES Brasiliana in Brazil. Mr. Gluski is also Chairman of the Americas Society/Council of the Americas, and Director of the Edison Electric Institute and the US-Philippines Society. 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.

Elizabeth Hackenson, 55 years old, was named Chief Information Officer ("CIO") and SVP of AES in October 2008. Prior to assuming her current position, Ms. Hackenson was the SVP and CIO at Alcatel-Lucent from 2006 to 2008, where she managed the development of technology programs for Applications, Operations and Infrastructure. Previously, she also served as the EVP and CIO for MCI from 2004 to 2006. Her corporate tenure has spanned several Fortune 100 companies

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including, British Telecom (Concert), AOL (UUNET) and EDS. She served in a variety of senior management positions, working on the management and delivery of information technology services to support business needs across a corporate-wide enterprise. Ms. Hackenson serves on the Boards of Dayton Power & Light ("DP&L") and its parent company DPL, Inc. AES Cochrane and AES Chivor. She also serves as a Director on the Greater Washington Board of Trade and Red 5 Security and is a Strategic Advisor to the Paladin Group. Ms. Hackenson earned her degree from New York State University.

Tish Mendoza, 40 years old, is Chief Human Resources Officer and Senior Vice President, Global Human Resources and Internal Communications. 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, DC. 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.

Brian A. Miller, 50 years old, is an EVP of the Company, General Counsel, and Corporate Secretary. Mr. Miller joined the Company in 2001 and has served in various positions including VP, Deputy General Counsel, Corporate Secretary, General Counsel for North America and Assistant General Counsel. Mr. Miller served on the Boards of AES Entek, a joint venture between AES and Koc Holdings in Turkey, from 2010 through 2014; and Silver Ridge Power, a joint venture between AES and Riverstone Holdings LLC, from 2008 through July of 2014. Mr. Miller is the chairman of Indianapolis Power and Light Board and DP&L. Mr. Miller also serves as a member of the Board of DPL, Inc. and AES Chivor. Prior to joining AES, he was an attorney with the law firm Chadbourne & Parke, LLP. Mr. Miller received a Bachelor's degree in History and Economics from Boston College and holds a Juris Doctorate from the University of Connecticut School Of Law.

Thomas M. O'Flynn, 56 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. ("TDI"), 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 the IPALCO and AES US Investments Boards and serves as a member of the Boards of DP&L and its parent company, DPL, Inc. Mr. O'Flynn 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 is Chairman of the Institute for Sustainability and Energy at Northwestern University. 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 26, 2015.

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, 2015, we had approximately $20.8 billion of outstanding indebtedness on a consolidated basis. All outstanding borrowings under The AES Corporation's senior secured credit facility 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 that is available for future secured debt or credit support and reduces our flexibility in dealing with 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 the likelihood of a downgrade of our debt, which could cause future debt costs and/or payments to increase under our debt and related hedging instruments and consume an even greater portion of cash flow;
- 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 12—Debt included in Item 8. 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. All of The AES Corporation's revenue is generated through its subsidiaries. Accordingly, 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. In addition, the payment of dividends or the making of loans, advances or other payments to The AES Corporation may be subject to other contractual, legal or regulatory restrictions or may be prohibited altogether. Business performance and local accounting and tax rules may limit the amount of retained earnings that may be distributed to us as a dividend. 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. Any right that The AES Corporation has to receive any assets of any of its subsidiaries upon any liquidation, dissolution, winding up, receivership, reorganization, bankruptcy, insolvency or similar proceedings (and the consequent right of the holders of The AES Corporation's indebtedness to participate in the distribution of, or to realize proceeds from, those assets) will be effectively subordinated to the claims of any such subsidiary's creditors (including trade creditors and holders of debt issued by such subsidiary).
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, letter of credit reimbursement agreements and agreements to pay, in certain circumstances, the project lenders or other parties.
As of December 31, 2015, we had approximately $20.8 billion of outstanding indebtedness on a consolidated basis, of which approximately $5.0 billion was recourse debt of The AES Corporation and approximately $15.8 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 $1.0 billion as of December 31, 2015. 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;
- causing The AES Corporation to record a loss in the event the lender forecloses on the assets;

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- triggering defaults in The AES Corporation's outstanding debt and trust preferred securities. For example, The AES Corporation's senior secured credit facility 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;
- the loss or impairment of investor confidence in the Company; or
- foreclosure on the assets that are pledged under the non-recourse loans, therefore 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 and preferred dividends;
- 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. 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. For example, in recent years, certain financial institutions have gone bankrupt. In the event that a bank who is party to our senior secured credit facility or other facilities goes bankrupt or is otherwise unable to fund its commitments, we would need to replace that bank in our syndicate or risk a reduction in the size of the facility, which would reduce our liquidity. In addition, our cash flow may not be sufficient to repay at maturity the entire principal outstanding under our credit facility 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;
- investor confidence;
- 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 of 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 often reflect the 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 supply 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;
- electricity usage;

- seasonality;
- foreign exchange rate fluctuation;
- availability and price of emission credits;
- hydrology and other weather conditions;
- illiquid markets;
- transmission or transportation constraints or inefficiencies;

- availability of competitively priced renewables sources;
- increased adoption of distributed generation;
- 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;
- geopolitical concerns affecting global supply of oil and natural gas;
- 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. See Item 7A.—Quantitative and Qualitative Disclosures about Market Risk to this Form 10-K for further information.

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.

Our coal-fired facilities in the US continue to face substantial challenges as a result of high coal prices relative to natural gas, particularly those which are merchant plants that are exposed to market risk and those that have hybrid merchant risk, meaning those businesses that have a PPA in place but purchase fuel at market prices or under short term contracts. 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 certain 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. We have also hedged a portion of our exposure to power price fluctuations through forward fixed price power sales. 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 has been volatile and may continue to be volatile in future periods.

The market price for our common stock has been volatile in the past, and the price of 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—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 United States, including in developing countries, which presents significant risks.

A significant amount of our revenue is generated outside the United States 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;