AES CORP
Form 10-K
February 26, 2015

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, 2014
-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 Smaller reporting company o

(Do not check if a smaller 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, 2014, the last business day of the Registrant's most recently completed second fiscal quarter (based on the adjusted closing sale price of $15.32 of the Registrant's Common Stock, as reported by the New York Stock Exchange on such date) was approximately $10.17 billion.

The number of shares outstanding of Registrant's Common Stock, par value $0.01 per share, on February 18, 2015 was 702,634,251

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Registrant's Proxy Statement for its 2015 annual meeting of stockholders are incorporated by reference in Parts II and III

THE AES CORPORATION
FISCAL YEAR 2014 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
ANEEL	Brazilian National Electric Energy Agency
APS	Attributed Profit System
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
CA	Commercial Availability
CAA	United States Clean Air Act
CAIR	Clean Air Interstate Rule
CAMMESA	Wholesale Electric Market Administrator in Argentina
CCB	Coal Combustion Byproducts
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
CEEE	Companhia Estadual de Energia
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
CO_2	Carbon Dioxide
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CPCN	Certificate of Public Convenience and Necessity
CPI	United States Consumer Price Index
CREG	Energy and Gas Regulation Commission
CRES	Competitive Retail Electric Service
CSAPR	Cross-State Air Pollution Rule
CVA	Credit Valuation Adjustment
CWA	U.S. Clean Water Act
DAREM	Kazakhstan regulator
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
DPLER	DPL Energy Resources, Inc.

DPP	Dominican Power Partners
ECCRA	Environmental Compliance Cost Recovery Adjustment
ED	East Kazakhstan Ecology Department
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
ESP	Electric Service Plan
ESPS	Existing Source Performance Standards
EU ETS	European Union Greenhouse Gas Emission Trading Scheme
EURIBOR	Euro Inter Bank Offered Rate
EUSGU	Electric Utility Steam Generating Unit
EVN	Vietnam Electricity
EVP	Executive Vice President
EWG	Exempt Wholesale Generators
FAC	Fuel Adjustment Charges
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
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
HAP	Hazardous Air Pollutant
HLBV	Hypothetical Liquidation Book Value
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
MINT	Kazakhstan Ministry of Industry and New Technology
MISO	Midcontinent Independent System Operator, Inc.
MME	Ministry of Mines and Energy
MRE	Energy Reallocation Mechanism
MW	Megawatts
MWh	Megawatt Hours

NCRE	Non-conventional Renewable Energy
NEK	Natsionala Elektricheska Kompania (state-owned electricity public supplier in Bulgaria)
NERC	North American Electric Reliability Corporation
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGCC	Natural Gas Combined Cycle
NIE	Northern Ireland Electricity
NODA	Notice of Data Availability
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
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
RC&OA	Retail Competition and Open Access
RCRA	Resource Conservation and Recovery Act
RGGI	Regional Greenhouse Gas Initiative
RMRR	Routine Maintenance, Repair and Replacement
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
SCJ	Superior Court of Justice
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
UTB	Unrecognized Tax Benefit
VIE	Variable Interest Entity
Vinacomin	Vietnam National Coal-Mineral Industries Group
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 post retirement 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 (formerly EMEA), 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, as discussed 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.

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SBU	Generation Capacity (Gross MW)		Generation Facilities	Utility Customers	Utility GWh	Utility Businesses
US						
Generation	5,825		12			
Utilities	6,520		18	1.1 million	34,797	2
Andes						
Generation	8,032		32			
Brazil						
Generation	3,298		13			
Utilities				8.0 million	57,274	2
MCAC						
Generation	3,140		13			
Utilities				1.3 million	3,620	4
Europe						
Generation	6,699		11			
Asia						
Generation	1,218		3			
	34,732	(1)	102	10.4 million	95,691	8

(1) 27,595 proportional MW. Proportional MW is equal to gross MW of a generation facility times AES' equity ownership percentage in such facility.

Strategy

In 2011, we implemented a new strategy to maximize value for our shareholders and over the last three 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 three years, we have sold assets to generate $3.0 billion in equity proceeds for AES, decreasing the total number of countries where we have operations from 28 to 18. 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 2014, we raised $1.8 billion in asset sales proceeds and exited three countries.
- Leveraging Our Platforms. We are focusing our growth on platform expansions, including adjacencies, in markets where we already operate and have a competitive advantage to realize attractive risk-adjusted returns. We currently have 7,141 MW under construction — the most in AES' 34-year history. These projects represent $9 billion in total capital expenditures, with the majority of AES' $1.5 billion in equity already funded and we expect all of these projects to come on-line from 2015 through 2018. In 2014, we brought on-line the 247 MW heavy fuel oil-fired IPP4 power plant in Jordan and broke ground on six new construction projects, totaling 2,226 MW. Beyond the projects we currently have under construction, we will continue to advance select projects from our 12,000 MW development pipeline, including traditional power plants and adjacencies, such as energy storage. Adjacencies are smaller investments that add near-term growth and can be replicated across our portfolio. We are already successful - AES is the world leader in battery-based energy storage, with 228 MW (power plant equivalent dispatchable resource, including supply and load capability) in operation or under construction.
AES has the most comprehensive and accomplished fleet of battery-based energy storage in the world
U.S. Energy Information Administration (EIA) forecasts 28,000 MW of new renewable capacity in the next ten years and 82,000 MW of power plant retirements over the same period
Energy storage can serve as a replacement resource, to absorb renewable energy
AES Advancion is a complete battery-based grid resource offered to utility companies and renewable developers
Tailored to specific market needs in terms of power and duration
- 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. We have reduced our global general & administrative expenses ("G&A") by

$200 million, achieving the goal we established in 2011 one year early.

- 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. In 2014, we brought in partners at four of our businesses:

CDPQ, a long-term institutional investor headquartered in Quebec, Canada, recently purchased direct and indirect interests in IPALCO, the Parent Company of IPL in Indiana, for $595 million.

At Guacolda in Chile, we brought in Global Infrastructure Partners to acquire a 50% stake by investing $728 million, which allowed us to improve operations, without changing our ownership stake.

At Masinloc in the Philippines, Electricity Generating Company Limited ("EGCO"), a Thailand-based Independent Power Producer, took an indirect stake in the existing business, as well as potential expansion opportunities, for $443 million. AES and EGCO agreed to use the Masinloc platform as their exclusive vehicle for growth in the Philippines.
At AES Dominicana in the Dominican Republic, we sold a minority interest in the business to the Estrella and Linda Groups, for $84 million, valuing our assets in the country at $1.2 billion. Estrella and Linda Groups represents strong local players and will support our planned platform expansions, such as upgrading our DPP power plant in the Dominican Republic.

- 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 $985 million of our shares and benefited from a low interest rate environment, by transacting on $18 billion in debt deals at the Parent and our subsidiaries. These debt transactions represent $9 billion in refinancing and $9 billion in new financing and extended the maturities on $2.9 billion in Parent debt.

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

Most recently, we doubled our regular dividend, increasing the quarterly payment to $0.10 per share beginning in the first quarter of 2015. This dividend increase reflects our confidence in the predictability and growth of our cash flow.

Generation

We currently own and/or operate a generation portfolio of 28,212 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 Fuel Costs). 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.

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, 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 of this Form 10-K.

35% 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.

30% of our generation fleet is coal-fired. In the United States, 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.
29% of our generation plants are fueled by renewables, including hydro, wind and energy storage, which do not have significant fuel costs.
6% 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 8,221 MW (4,364 proportional MW) of renewable generation, including hydro, wind, energy storage, 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 more than 10 million people in three countries. AES’ two utilities in the United States also include generation capacity totaling 6,520 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, a non-GAAP measure (see definition below).

AES' primary sources of Revenue, Operating Margin and Adjusted PTC are from generation and utility businesses. The Adjusted PTC by SBU for the year ended December 31, 2014 is shown below. The percentages shown are the contribution by each SBU to gross Adjusted PTC, 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 2014, approximately 79% of Adjusted PTC was contributed by our businesses in the Americas —including the US, Andes, Brazil and MCAC SBUs. Asia and Europe accounted for the remaining 21%.

We define Adjusted PTC as pretax income from continuing operations attributable to AES excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses related to derivative transactions, (b) unrealized foreign currency gains or losses, (c) gains 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 also includes net equity in earnings of affiliates on an after-tax basis, adjusted for the aforementioned items. Adjusted PTC in each SBU includes the effect of intercompany transactions with other SBUs other than interest and charges for certain management services.

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 — led by our Chief Executive Officer ("CEO"):

- US SBU
- Andes SBU
- Brazil SBU
- MCAC SBU
- Europe SBU
- Asia SBU

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. 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 used for financial reporting purposes.

"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 Note 17—Segment and Geographic Information included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for information on revenue from external customers, Adjusted PTC (a non-GAAP measure) and total assets by segment.

The following describes our businesses within our six SBUs:

US SBU

Our US SBU has 12 generation facilities and two integrated utilities in the United States. Our US operations accounted for 23%, 21% and 20% of consolidated AES operating margin and 24%, 24% and 20% of AES Adjusted PTC (a non-GAAP measure) in 2014, 2013 and 2012, respectively. The percentages reflect the contribution by our US SBU to gross operating margin and adjusted PTC before deductions for Corporate.

The following table provides highlights of our US operations:

Generation Capacity	12,345 gross MW (12,345 proportional MW)
Generation Facilities	15 (including 3 under construction)
Key Generation Businesses	Southland, Hawaii and US Wind
Utilities Penetration	1,125,000 customers (34,797 GWh)
Utility Businesses	2 integrated utilities (includes 18 generation plants)
Key Utility Businesses	IPL and DPL

Operating installed capacity of our US SBU totals 12,345 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.

Set forth in the table below is a list of our US generation businesses:

Business	Location	Fuel	Gross MW	AES Equity Ownership (% Rounded)		Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Southland—Alamitos	US-CA	Gas	2,075	100	%	1998	2018	Southern California Edison
Southland—Redondo Beach	US-CA	Gas	1,392	100	%	1998	2018	Southern California Edison
Southland—Huntington Beach	US-CA	Gas	474	100	%	1998	2018	Southern California Edison
Shady Point	US-OK	Coal	360	100	%	1991	2018	Oklahoma Gas & Electric
Buffalo Gap II(1)	US-TX	Wind	233	100	%	2007	2017	Direct Energy
Hawaii	US-HI	Coal	206	100	%	1992	2022	Hawaiian Electric Co.
Warrior Run	US-MD	Coal	205	100	%	2000	2030	First Energy
Buffalo Gap III(1)	US-TX	Wind	170	100	%	2008	2015	Direct Energy
Beaver Valley	US-PA	Coal	132	100	%	1985		
Buffalo Gap I(1)	US-TX	Wind	121	100	%	2006	2021	Direct Energy
Armenia Mountain(1)	US-PA	Wind	101	100	%	2009	2024	Delmarva & ODEC
Laurel Mountain	US-WV	Wind	98	100	%	2011		
Mountain View I & II(1)	US-CA	Wind	67	100	%	2008	2021	Southern California Edison
Laurel Mountain ES(2)	US-WV	Energy Storage	64	100	%	2011		
Mountain View IV	US-CA	Wind	49	100	%	2012	2032	Southern California Edison
Tait ES(2)	US-OH	Energy Storage	40	100	%	2013		
Tehachapi	US-CA	Wind	38	100	%	2006	2015	Southern California Edison
			5,825					

(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) Energy Storage MW are power plant equivalent dispatchable resource, including supply and load capability.

Under construction

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

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)		Expected Date of Commercial Operations
IPL MATS	US-IN	Coal	2,400	100	%	1H 2016
Eagle Valley CCGT	US-IN	Gas	671	100	%	1H 2017
Warrior Run ES[(1)]	US-MD	Energy Storage	20	100	%	1H 2015
US Total			3,091			

(1) Energy Storage MW are power plant equivalent dispatchable resource, including supply and load capability.

Set forth in the tables below is a list of our US utilities and their generation facilities:

Business	Location	Approximate Number of Customers Served as of 12/31/2014	GWh Sold in 2014	AES Equity Interest (Percent, Rounded)		Year Acquired
DPL	US-OH	644,000	18,763	100	%	2011
IPL	US-IN	481,000	16,034	100	%	2001
		1,125,000	34,797			

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)		Year Acquired or Began Operation
DPL[(1)]	US-OH	Coal/Gas/Oil	3,066	100	%	2011
IPL[(2)]	US-IN	Coal/Gas/Oil	3,454	100	%	2001
			6,520			

(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, 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) IPL plants: Eagle Valley, Georgetown, Harding Street and Petersburg.

The following map illustrates the location of our US facilities:

US Businesses

US 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 480,000 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 a population of approximately 928,000. IPL owns and operates four generating stations. Two of the generating stations are primarily coal-fired. 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 3,241 MW and net summer capacity is 3,123 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, CDPQ will invest approximately $349 million in IPALCO through 2016, in exchange for a 17.65% equity stake, funding existing growth and environmental 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 US. 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, those to reflect changes in fuel costs to generate electricity or purchased power prices, referred to as FAC, and 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 by approximately $67.8 million annually, or 5.6%. Hearings have begun on this proceeding and an order on this proceeding will likely be issued in the fourth quarter of 2015 with any rate change expected to become effective by early 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. Pursuant to an Indiana statute, 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 in the next few years. 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 (106 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 $626 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 IPL is allowed to collect a return. The CCGT is expected to be placed into service in April 2017, and the refueling project is expected to be completed in 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). This conversion is part of IPL’s overall wastewater compliance plan for its power plants (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 as part of an agreed order with IDEM. IPL conducted studies to determine the operational changes and/or control equipment necessary in order to comply with the new limitations. On October 16, 2014, IPL filed its wastewater compliance plans with the IURC. IPL is seeking approval for a CPCN to install and operate wastewater treatment technologies at its Petersburg Plant and Harding Street Station, as well as for the refueling of Unit 7 at Harding Street. If approved, IPL will invest $332 million in these projects to ensure compliance with the wastewater treatment requirements by 2017. IPL cannot predict the impact of these regulations on IPL's consolidated results of operations, cash flows, or financial condition, but it is expected to be material. 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 Environmental Matters 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 more than 515,000 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 260,000 retail customers in Ohio and Illinois. Approximately 131,000 of these customers are also distribution customers of DP&L in Ohio.

Market Structure

Customer Switching. Since January 2001, electric customers within Ohio have been permitted to choose to purchase power under a contract with a CRES Provider or continue to purchase power from their local utility under SSO rates established by 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 has 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. Ten percent of the SSO load was sourced through competitive bid in 2014, and an additional 50% and 100% will be sourced in this manner in 2015 and 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). Several communities in DP&L's service area have passed ordinances allowing the communities to become government aggregators for the purpose of offering retail generation service to their residences.

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. The RPM is PJM's capacity construct. The purpose of the RPM 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. DP&L's capacity is located in the remainder of the RTO area within PJM.

The PJM RPM auctions are held three years in advance for a period covering 12 months starting from June 1. Auctions for the period covering June 1, 2018 through May 30, 2019 are expected to take place in May 2015. 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 RPM capacity auctions. For DPL-owned generation, applicable capacity prices and capacity cleared for periods through the auction year 2017/18 are as follows:

Auction Year (June 01-May 31)	2017/18	2016/17	2015/16	2014/15	2013/14	2012/13
Capacity Clearing Price ($/MW-Day)	$120	$59	$136	$126	$28	$16
Capacity Cleared (MW)	2,960	2,957	2,923	3,277	3,283	3,609

On a calendar-year basis, capacity prices and annual capacity revenues earned or projected to be earned by DPL are as follows:

Year	2017	2016	2015	2014	2013
Computed Average Capacity Price ($/MW-Day)	$95	$91	$132	$85	$23
Computed Gross RPM Capacity Revenue ($ millions)	$103	$97	$147	$107	$29

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. Accordingly, in 2014, DP&L credited 29% of the RPM capacity revenue to SSO customers. However, with ongoing switching and transitioning to the market, the amount to be credited will decline each year until reaching zero by 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 to any customer that has not signed a contract with a CRES provider at SSO rates. SSO rates are subject to rules and regulations of the PUCO and are established based on an 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.

On October 5, 2012, DP&L filed an ESP with the PUCO to establish SSO rates that were to be in effect starting January 2013. An order was issued by the PUCO on September 4, 2013 and a correction to that order was issued on September 6, 2013 ("ESP Order"). After several rehearing requests the ESP Order was revised several times. Collectively, the ESP Orders state that DP&L's current ESP began January 2014 and extends through May 31, 2017. The PUCO authorized DP&L to collect a non-bypassable SSR equal to $110 million per year for 2014 - 2016. The ESP Order also directed DP&L to divest its generation assets no later than January 1, 2017 and established DP&L's Significantly Excessive Earnings Test ("SEET") threshold at a 12% ROE. Beginning in 2014, DP&L was no longer permitted to supply 100% of the generation service for SSO customers. Instead, the PUCO directed DP&L to phase in the competitive bidding structure with 10% of DP&L's SSO load sourced through the competitive bid starting in 2014, 60% in 2015, and 100% by January 1, 2016. The ESP Order approved DP&L's rate proposal to bifurcate its transmission charges into a non-bypassable component, Transmission Cost Recovery Rider - Nonbypassable ("TCRR-N") and a bypassable component, Transmission Cost Recovery Rider - Bypassable ("TCRR-B"). The ESP

order also required DP&L to establish a $2.0 million per year shareholder funded economic development fund.
In accordance with the ESP Order, on December 30, 2013, DP&L filed an application with the PUCO stating its plan to transfer or sell its generation assets. After a period of comments and response, DP&L filed amended applications on February 25, 2014 and May 23, 2014. On June 4, 2014, the PUCO issued a fourth entry on rehearing which reinstated the time by which DP&L must separate its generation assets from its transmission and distribution assets to no later than January 1, 2017. On July 14, 2014, DP&L publicly announced its decision to retain DP&L's generation assets but to maintain its plans to transfer the

assets to a separate affiliate of DPL in accordance with the PUCO orders by January 1, 2017. On September 17, 2014, the PUCO issued a Finding and Order which approved DP&L's plan to separate its generation assets with minor modifications. These modifications denied DP&L's request to defer costs associated with Ohio Valley Electric Corporation (which are not currently being recovered through existing rates) and ordered DP&L to transfer environmental liabilities with the generation assets.

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.

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 (as discussed above)
- Non-bypassable revenue: $110 million in 2014 and allowed to earn $110 million annually in 2015 and 2016
- Customer switching, competitive bidding and SSO rates (as discussed above)
- Retail margins earned at DPLER

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 $437 million in capital projects for the period 2015 through 2017. 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.

US Generation

Business Description. In the US, we own a diversified generation portfolio in terms of geography, technology and fuel source. The principal markets 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, which expires in mid-2018 (the "Tolling Agreement"). Under the Tolling Agreement, AES Southland's largest revenue driver is unit availability, as approximately 98% 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 Independent System Operator’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 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, construction is expected to begin in 2017, and commercial operation is 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 US 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 US Generation Businesses

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

Many of our US 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, 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 2017; the business could be subject to variability in coal pricing beginning in January 2018. To mitigate fuel risk beyond December 2017, 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 877 MW of wind capacity in the US, located in California, Pennsylvania, Texas and West Virginia. 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. The energy price of the entire production of Buffalo Gap I is guaranteed by a

PPA expiring in 2021. The PPAs of Buffalo Gap II and Buffalo Gap III guarantee 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 PPAs of Buffalo Gap II and Buffalo Gap III expire in December 2017 and December 2015, respectively. 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 US, 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 US 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. Many of these generation businesses have entered into long-term PPAs with utilities or other offtakers. Some coal-fired power plant businesses in the US 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 United States 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 United States 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 US wholesale electricity market consists of multiple distinct regional markets that are subject to both federal regulation, as implemented by the US 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 US 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 US business, see Item1.—US Environmental and Land-Use Legislation and Regulations.

Key Financial Drivers

US 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 and an energy storage project that will be adjacent to the existing Warrior Run coal plant located in Maryland. In addition to the new construction projects, US 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. Our Andes operations accounted for 19%, 17% and 16% of consolidated AES Operating Margin and 23%, 19% and 18% of AES Adjusted PTC (a non-GAAP measure) in 2014, 2013 and 2012, respectively. The percentages reflect the contribution by our Andes SBU to gross Operating Margin and Adjusted PTC before deductions for Corporate.

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 71% ownership interest in AES Gener and this business is consolidated in our financial statements.

The following table provides highlights of our Andes operations:

Countries	Chile, Colombia and Argentina
Generation Capacity	8,032 gross MW (6,354 proportional MW)
Generation Facilities	38 (including 6 under construction)
Key Generation Businesses	AES Gener Chile, Chivor and AES Argentina

Operating installed capacity of our Andes SBU totals 8,032 MW, of which 44%, 44% and 12% is located in Argentina, Chile and Colombia, respectively. Set forth 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	71	%	2000	Short-term	Various
Colombia Subtotal			1,000					
Electrica Santiago[1]	Chile	Gas/Diesel	750	71	%	2000		
Gener - SIC[2]	Chile	Hydro/Coal/Diesel/Biomass	716	71	%	2000	2015-2037	Various
Guacolda[3] [4]	Chile	Coal/Pet Coke	608	35	%	2000	2015-2032	Various
Electrica Angamos	Chile	Coal	545	71	%	2011	2026-2037	Minera Escondida, Minera Spence, Quebrada Blanca
Gener - SING[5]	Chile	Coal/Pet Coke	277	71	%	2000	2015-2037	Minera Escondida, Codelco, SQM, Quebrada Blanca
Electrica Ventanas[6]	Chile	Coal	272	71	%	2010	2025	Gener
Electrica Campiche[7]	Chile	Coal	272	71	%	2013	2020	Gener
Electrica Angamos ES[8]	Chile	Energy Storage	40	71	%	2011		
Gener - Norgener ES (Los Andes)[8]	Chile	Energy Storage	24	71	%	2009		
Chile Subtotal			3,504					
TermoAndes[9]	Argentina	Gas/Diesel	643	71	%	2000	Short-term	Various
AES Gener Subtotal			5,147					
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	2015	Various
Los Caracoles[10]	Argentina	Hydro	125	—	%	2009	2019	Energia Provincial Sociedad del Estado (EPSE)
Cabra Corral	Argentina	Hydro	102	100	%	1995		Various
Ullum	Argentina	Hydro	45	100	%	1996		Various
Sarmiento	Argentina	Gas/Diesel	33	100	%	1996		
El Tunal	Argentina	Hydro	10	100	%	1995		Various
Argentina Subtotal			2,885					

Andes Total	8,032

(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, San Francisco de Mostazal, Ventanas 1, Ventanas 2 and Volcán.
(3) Guacolda plants: Guacolda 1, Guacolda 2, Guacolda 3 and Guacolda 4. Unconsolidated entities for which the results of operations are reflected in Equity in Earnings of Affiliates.
(4) The Company's ownership in Guacolda is held through AES Gener, a 71%-owned consolidated subsidiary. AES Gener owns 50% of Guacolda, resulting in an AES effective ownership in Guacolda of 35%.
(5) Gener - SING plants: Norgener 1 and Norgener 2.
(6) Electrica Ventanas plant: Nueva Ventanas.
(7) Electrica Campiche plant: Ventanas 4.
(8) Energy Storage MW are power plant equivalent dispatchable resource, including supply and load capability.
(9) TermoAndes is located in Argentina, but is connected to both the SING in Chile and the SADI in Argentina.
(10) 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	42 %	2H 2016
Alto Maipo	Chile	Hydro	531	42 %	2H 2018
Guacolda V	Chile	Coal	152	35 %	2H 2015
Cochrane ES[1]	Chile	Energy Storage	40	42 %	2H 2016
Andes Solar	Chile	Solar	21	71 %	2H 2015
Chile Subtotal			1,276		
Tunjita	Colombia	Hydro	20	71 %	1H 2015
Colombia Subtotal			20		
Andes Total			1,296		

(1) Energy Storage MW are power plant equivalent dispatchable resource, including supply and load capability.

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 3,440 MW, excluding energy storage and TermoAndes, and a market share of 17.9% as of December 31, 2014.

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 to the SIC and SING. AES Gener has experienced significant growth in recent years responding to market opportunities with the completion of nine generation projects totaling approximately 1,700 MW and increasing AES Gener's installed capacity by 49% from 2006 to 2014. Additionally, we are constructing an additional 1,276 MW, comprised of the 21 MW Andes Solar and 40 MW Cochrane Energy Storage in the SING, the 152 MW coal-fired Guacolda V in the SIC, 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 with their efficient generation capacity, 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 U.S. Consumer Price Index ("U.S. 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 U.S. CPI and other relevant indices.

Market Structure. Chile has four 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 15,181 MW as of December 31, 2014. The SIC serves approximately 92% of the Chilean population, including the densely populated Santiago Metropolitan Region, and represents 75% of the country's electricity demand. The SING serves about 6% of the Chilean population, representing 24% of Chile's electricity consumption, and is mostly oriented toward mining companies.

In 2014, thermoelectric generation represented 64% of the total generation in Chile. In the SIC, thermoelectric generation represents 52% 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 95% 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 2014 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 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 100% 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, NOx 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, 2014, AES Gener has invested approximately $204 million and expects the remaining $48 million will be invested in 2015 in order to comply within the required time frame. Additionally, its equity method investee Guacolda started the installation of new equipment during 2013, as of December 31, 2014 spending approximately $114 million (Guacolda I, II and IV) and the remaining $107 million will be invested between 2015 and 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 6% 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 particulate material (PM), SO_2, NO_x and CO_2 produced for installations with an installed capacity over 50 MW. This new tax will be in force from 2017. In the case of CO_2, the tax will be equivalent to $5 per ton of CO_2 emitted. AES Gener is currently assessing the impacts of the new tax and possible mitigation strategies.

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:

- Availability of hydro generation: dry hydrology scenarios reduce hydro generation
- Availability of generation: forced outages may impact earnings
- Regulatory rulings: a change in current governmental rulings could alter the ability to pass through or recover certain costs
- Foreign exchange: 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

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

- Generation margins: current legislation is trending towards rewarding renewable energy and penalizing coal assets, posing a risk to future coal margins

Construction and Development

Since 2007, AES Gener has constructed and initiated commercial operations of approximately 1,700 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 second half of 2015, two coal-fired projects under construction with gross capacity of 684 MW, 152 MW of which is represented by Guacolda V in the northern part of the SIC, scheduled to begin operations in the second half of 2015 and the 532 MW Cochrane project in the SING, expected to begin operations in 2016. The Cochrane project includes a 40 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. Alto Maipo is the largest permitted project in the SIC market and includes 67 kilometers of tunnel work as part of the construction. This project is scheduled to start operations in 2018 and is expected to represent approximately 4% of the energy demand in the SIC at that time.

Colombia

Business Description. As of December 31, 2014, AES Gener's net power production in Colombia was 3,985 GWh (6% of the country's total generation). Chivor, a subsidiary of AES Gener, owns a hydroelectric facility with installed capacity of 1,000 MW, located approximately 160 km east of Bogota. The installed capacity represents approximately 6.4% of system capacity as of December 31, 2014. 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 on selling between 75% and 85% of the annual 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 15,528 MW as of December 31, 2014, comprised of 69.3% hydroelectric generation, 29.8% thermoelectric generation and 0.9% 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 2014, 70.7% of total energy demand was supplied by hydroelectric plants with the remaining supply from thermoelectric generation (28.6%) and cogeneration and self-generation power (0.7%). From 2003 to 2014, electricity demand in the SIN has grown at a compound annual growth rate of 3% and the UPME projects an average compound annual growth rate in electricity demand of 2.3% 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 Ministry of Mines and Energy, which defines the government's policy for the energy sector; the Public Utility Superintendency of Colombia, which is in charge of overseeing 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 February 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 must develop 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. 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.

Key Financial Drivers

Hedge levels at Chivor provide a high degree of certainty and clarity on the underlying financial drivers through 2016, however, some risks remain beyond 2016.

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

- Availability of generation: forced outages may impact earnings
- Availability of hydro generation: dry hydrology scenarios reduce hydro generation
- Foreign exchange: 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:

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

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.

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 2015.

Argentina

Business Description. As of December 31, 2014, AES Argentina operates 3,508 MW which represents 11% of the country's total installed capacity. The installed capacity in the SADI includes the TermoAndes plant, a subsidiary of AES Gener, which is connected both to the SADI and the Chilean SING. AES Argentina has a diversified generation portfolio of ten generation facilities, comprised of 61% thermoelectric and 39% 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 or fuel oil.

AES Argentina primarily sells its production to the wholesale electric market where prices are largely regulated. In 2014, 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 the CAMMESA.

All of the thermoelectric facilities not affected by the Resolution 95/2013, including TermoAndes, 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, 2014, the installed capacity of the SADI totaled 32,371 MW. In 2014, 63% 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, the wholesale electric market administrator, 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 under construction. 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 applies to all of AES Argentina's plants, excluding TermoAndes. Based on Note 2053 sent by the Ministry of Energy in March 2013, it is understood that TermoAndes' units are 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 90 MW of capacity into the system. CAMMESA will finance the investment utilizing the outstanding receivables as a guarantee.
Key Financial Drivers
Financial results are likely to be driven by many factors including, but not limited to, the following:
- Availability of generation - forced outages may impact earnings
- Exposure to fluctuations of the Argentine peso
- Hydrology
- Lack of subsequent regulatory adjustments for cost increases
- Timely collection of FONINVEMEM installment and outstanding receivables
- Level of gas prices for contracted generation (Energy Plus)
- Access to foreign exchange for imports

See Item 7.—Key Trends and Uncertainties—Argentina for further discussion of Argentina.
Brazil SBU
Our Brazil SBU has generation and distribution businesses. Our Brazil operations accounted for 24%, 27% and 27% of consolidated AES Operating Margin and 13%, 12% and 16% of consolidated AES Adjusted PTC (a non-GAAP measure) in 2014, 2013 and 2012, respectively. The percentages reflect the contribution by our Brazil SBU to gross operating margin and Adjusted PTC before deductions for Corporate.
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.
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	8.0 million customers (57,274 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, 2014, 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 the South of Brazil with an installed capacity of 640 MW.
Set forth in the table below is a list of 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	2015	Eletropaulo
Uruguaiana	Brazil	Gas	640	46	%	2000		
Brazil Total			3,298					

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(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 20.1 million people and 6.7 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 3.5 million people and 1.3 million consumer units.

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

Business	Location	Approximate Number of Customers Served as of 12/31/2014	GWh Sold in 2014	AES Equity Interest (% Rounded)		Year Acquired
Eletropaulo	Brazil	6,682,000	47,583	16	%	1998
Sul	Brazil	1,270,000	9,691	100	%	1997
		7,952,000	57,274			

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 sells nearly 100% of its assured capacity, approximately 11,108 GWh, to Eletropaulo under a long-term PPA, which is expiring in December 2015. The contract is price-adjusted annually for inflation, and as of December 31, 2014, the price was R$206/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, 2014, Tietê's contracted portfolio position is 83% and 73% with average prices of R$132/MWh and R$133/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 in 2014 caused an increase in energy prices going forward. Tietê is closely monitoring and analyzing system supply conditions to support energy commercialization decisions. In 2014, 31 new contracts were signed at an average price of approximately R$147/MWh. Tietê's current view on energy prices for 2016 is in the range of R$245 - R$265/MWh, prior to adjustment for inflation, depending on the length of the contract (vs. R$125-R$135/MWh expectation in the beginning of 2014). 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 eventual Assured Energy reduction 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. Future prices could vary materially, depending on the supply and demand for electricity, hydrology and other market conditions.

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. 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 (February and March) and 2014 (March, April, and May) due to the short-term supply of LNG for the facility. Uruguaiana continues to work towards securing gas on a long-term basis.

Market Structure. Brazil has installed capacity of 123,973 MW, which is 74% hydroelectric, 16% thermal and 10% renewable (biomass and wind). Brazil's national grid is divided into four subsystems. Tietê sells into the Southeast subsystem of the national grid, while Uruguaiana sells into 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.

Hydrological risk is shared among hydroelectric generation plants through the MRE. 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 as well and they are able to make extra revenues selling the excess energy on the spot market.

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$690/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 forward. The lower cap price will result in a meaningful reduction on the expenses of the agents that are negatively exposed to the spot price in 2015. AES’ expectation for 2015 is that spot prices will be near the new regulatory cap of R$388/MWh and hydro power generators may purchase energy due to lower Assured Energy in the system as a result of unfavorable hydrological conditions. See Item 7. Key Trends and Uncertainties- Operational - Weather Sensitivity for further information.

Key Financial Drivers

As the system is highly dependent on hydroelectric generation, Tietê and Uruguaiana 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 sold
- Re-contracting price
- Asset management and plant availability
- Cost management

- Ability to execute on its growth strategy

Through and beyond 2016, Uruguaiana 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 a 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, the 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 weighted-average cost of capital ("Regulatory WACC"), which is set for all industry participants during each tariff reset cycle. The current Regulatory WACC, after tax, is 7.5%. For the next tariff cycle which will be applied in July 2015 at Eletropaulo, the Regulatory WACC, after tax, will be 8.1%. This WACC will be updated again in three years before the next tariff review at 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.

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 2015. Sul's tariff is reset every five years and the next tariff reset is expected in April 2018.

ANEEL has challenged the parameters of a tariff reset for Eletropaulo implemented in July 2012 and retroactive to 2011. ANEEL has 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 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.

Key Financial Drivers

Through and beyond 2016, Eletropaulo and Sul 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
- Eletropaulo's Fourth tariff cycle outcomes in July 2015
- 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).

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. In addition, Eletropaulo is involved in a dispute with Centrais Elétricas Brasileiras S.A. ("Eletrobrás") regarding a liability from the privatization of Eletropaulo. See Item 3.—Legal Proceedings for further discussion of this dispute. If Eletropaulo is found liable in the dispute, Eletropaulo's results from operations could be materially affected.

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 3,140 MW and distribution networks serving 1.3 million customers as of December 31, 2014. MCAC operations accounted for 18%, 17% and 16% of consolidated AES Operating Margin and 19%, 19% and 19% of consolidated AES Adjusted PTC (a non-GAAP measure) in 2014, 2013 and 2012, respectively. The percentages reflect the contribution by our MCAC SBU to gross Operating Margin and Adjusted PTC 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	3,140 gross MW (2,434 proportional MW)
Generation Facilities	14 (including 1 under construction)
Key Generation Businesses	Andres, Panama and TEG TEP
Utilities Penetration	1.3 million customers (3,620 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	Gas	319	92	%	2003	2018	Ede Este/Non-Regulated Users/Linea Clave
Itabo[1]	Dominican Republic	Coal/Gas	295	46	%	2000	2016	Ede Este/Ede Sur/Ede Norte/Quitpe
DPP (Los Mina)	Dominican Republic	Gas	236	92	%	1996	2016	Ede Este
Dominican Republic Subtotal			850					
AES Nejapa	El Salvador	Landfill Gas	6	100	%	2011	2035	CAESS
El Salvador Subtotal			6					
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
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			705					
Puerto Rico	US-PR	Coal	524	100	%	2002	2027	Puerto Rico Electric Power Authority
Puerto Rico Subtotal			524					
MCAC Total			3,140					

(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
DPP (Los Mina) Conversion	Dominican Republic	Gas	122	92	%	1H 2017
			122			

Dominican Republic Subtotal						
Estrella del Mar I	Panama	Fuel Oil	72	49	%	1H 2015
Panama Subtotal			72			
MCAC Total			194			

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 in the table below:

Business	Location	Approximate Number of Customers Served as of 12/31/2014	GWh Sold in 2014	AES Equity Interest (% Rounded)		Year Acquired
CAESS	El Salvador	576,000	2,108	75	%	2000
CLESA	El Salvador	365,000	865	80	%	1998
DEUSEM	El Salvador	74,000	125	74	%	2000
EEO	El Salvador	283,000	522	89	%	2000
		1,298,000	3,620			

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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 40% 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 $84 million with an 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 46%-owned by AES, 4% 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 MWs of installed capacity. Itabo's PPAs are with government-owned distribution companies and expire in 2016.
Andres and DPP are owned 92% by AES and 8% 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. This translates into a competitive advantage as we are currently purchasing LNG at prices lower than those on the international market. 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.
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 2015 in order to secure supply and competitive pricing for actual and future distribution energy requirements. The existing business strategy is to secure approximately 70% to 80% 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.

Market Structure

Electricity Market. The Dominican Republic has one main interconnected system with approximately 3,700 MW of installed capacity, composed primarily of thermal generation (85%) and hydroelectric power plants (15%).

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 transportation and loading and compression plant; 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 2015 is close to 80%. 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.
- New market rules for ancillary services enacted in 2014, particularly with regard to primary frequency regulation, reduced the revenues in the latter part of the 2014 and may impact future earnings
- 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 122 MW of gross capacity at an estimated cost of $275 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 the first quarter 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 representing 705 MWs of installed capacity, or 26% of the installed capacity in Panama. The majority of our capacity in Panama is run-of-river, with the exception of the 260 MW Bayano project.

A portion of the distribution companies' PPAs will expire on December 2018 reducing the total contract capacity of the company from 424 MW to 350 MW and will remain at that level until December 2030.
Market Structure. Panama's current total installed capacity is 2,759 MW, of which 56% is hydroelectric, 2% wind and the remaining 42% 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 in 2014 reduced generation output from hydroelectric facilities and increased spot prices for electricity. From March to June 2014, the government of Panama implemented certain energy saving measures designed to reduce demand for electricity during peak hours by approximately 300 MW, which contributed to water savings in the key hydroelectric dams and lower spot prices. AES Panama had to purchase energy on the spot market to fulfill its contract obligations as its generation output was below contract levels. 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 high spot prices for the additional energy purchased to fulfill contracts, partially mitigated by the compensation agreement with the government and the power barge which is expected to be operational in the first half of 2015
- 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
- Spot prices are driven by hydrology since Panama is highly dependent on hydro generation (~56%), however, fluctuations in commodity prices, mainly oil prices, will affect the thermal generation cost impacting the spot prices and the opportunity cost of water

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 - Weather Sensitivity for further information.

Construction and Development.
Following the strategy to reduce reliance on hydrology, in September 2014 AES Panama acquired a a 72 MW gross capacity power barge for $27 million, financed with non-recourse debt. The barge arrived in Panama on September 25, 2014

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and is expected to become operational in the first half of 2015 with fuel to be supplied by Chevron. AES Panama executed a physical PPA for the supply of energy for a period of 5 years.

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.

Market Structure. Mexico has a single national electricity grid, the SEN, covering nearly all of Mexico's territory. Mexico has an installed capacity totaling 54 GW with a generation mix of 74% thermal, 21% hydroelectric and 5% other. Electricity consumption is split between the following end users: industrial (58%), residential (26%) and commercial and service (16%).

Regulatory Framework

The CFE, mandated by the Mexican Constitution, is the state-owned electric monopoly that operates the national grid and generates electricity for the public. CFE regulates wholesale tariffs which are largely set by the marginal production cost of oil and gas-fired generation. The Mexican energy system is fully integrated under the sole responsibility of CFE. The Electric Public Service Law allows privately owned projects to produce electricity for self-supply application and/or IPP structures.

Under current regulatory framework, private parties are allowed to invest in certain activities in Mexico's electric power market and obtain permits from the Ministry of Energy for: (i) generating power for self-supply; (ii) generating power through co-generation processes; (iii) generating power through independent production; (iv) small-scale production; and (v) importing and exporting electrical power. Permit holders are required to enter into PPAs with the CFE to sell all surplus power produced. Merida provides power exclusively to CFE under a long-term contract. TEG/TEP provides the majority of its output to two offtakers under long-term contracts and can sell any excess or surplus energy produced to CFE at a predetermined day-ahead price.

During 2014, the Mexican government promulgated the administrative regulations for the implementation of a new regulatory framework including the following aspects:

- Electricity Reform: implementing a complete restructuring of the industry including permitting process, terms and conditions for transmission and distribution services and a wholesale electricity market, among others. Under the proposed reform, the CFE will be transformed into a Productive State Enterprise, including separation of the vertically-integrated monopoly into generation, transmission, distribution and marketing activities.
- Regulations to the Geothermal Energy Law: setting forth details on terms and conditions of the permitting process and of the exploitation of the resources.

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 is a 524 MW coal-fired cogeneration plant utilizing CFB technology, representing approximately 9% of the installed capacity in Puerto Rico. The plant has a long-term PPA expiring in 2027 with the PREPA, a state-owned entity that supplies virtually all of the electric power consumed in Puerto Rico and generates, transmits and distributes electricity to 1.5 million customers. See Item 7. Key Trends and

Uncertainties—Macroeconomic and Political—Puerto Rico for further discussion of the long-term PPA with PREPA.
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 84% of the country. AES El Salvador accounted for 3,796 GWh of market energy purchases during 2014, or about 63% market share of the country's total energy purchases.

The sector is governed by the General Electricity Law and the general and specific orders 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 13%, 13% and 14% of AES consolidated Operating Margin and 19%, 19% and 18% of AES consolidated Adjusted PTC (a non-GAAP measure) in 2014, 2013 and 2012, respectively. The percentages reflect the contribution by our Europe SBU to gross Operating Margin and Adjusted PTC before deductions for Corporate.

The following table provides highlights of our Europe operations:

Countries	Bulgaria, Jordan, Kazakhstan, Netherlands and United Kingdom
Generation Capacity	6,699 gross MW (4,989 proportional MW)
Generation Facilities	11
Key Generation Businesses	Maritza, Kilroot, Ballylumford, and Kazakhstan

Operating installed capacity of our Europe SBU totaled 6,699 MW. Set forth 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	247	60	%	2014		
Jordan Subtotal			627					
Ust-Kamenogorsk CHP	Kazakhstan	Coal	1,354	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	301	100	%	1997	Short-term	Various
Kazakhstan Subtotal			2,688					
Elsta(2)	Netherlands	Gas	630	50	%	1998	2018	Dow Benelux, Delta, Nutsbedrijven, Essent Energy
Netherlands Subtotal			630					
Ballylumford	United Kingdom	Gas	1,246	100	%	2010	2023	Power NI and Single Electricity Market (SEM)
Kilroot(3)	United Kingdom	Coal/Oil	662	99	%	1992		SEM

United Kingdom Subtotal	1,908
Europe Total	6,699

(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 the only coal-fired power plant in Bulgaria that is fully compliant with the EU Industrial Emission Directive, which comes into force in 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 2014 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 practice, an organized market for trading electricity has not yet evolved, so NEK remains the main wholesale buyer for power generated in Bulgaria.
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, Bulgaria's State Energy and Water Regulatory Commission (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 could further impact 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, including taking one of Maritza's units out of the PPA and reducing the price of the remaining unit's output by 30%. Maritza has filed appeals of these SEWRC decisions with the Supreme Administrative Court in Bulgaria. In November 2014, SEWRC issued a new decision withdrawing the specific PPA amendment conditions and replacing with instructions to start negotiations without conditions. In addition, SEWRC announced that it has asked the Directorate-General for Competition of the European Commission (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.
On July 24, 2014, the Bulgarian government formally resigned and the caretaker government was appointed by the President. Preliminary parliamentary elections were held on October 5, 2014. Eight political parties were elected and the biggest party, supported by another three, formed a coalition government. Meanwhile, the caretaker government requested and received the resignations of the former chairman and two commissioners of the Regulator. The new leadership approved an end-consumer energy price increase of approximately 10% effective October 1, 2014, which is expected to slightly improve NEK's liquidity. At this time, it is difficult to predict the impact of these political conditions and regulatory changes on our businesses in Bulgaria.
Maritza has experienced ongoing delays in the collection of outstanding receivables from NEK. In November 2013, Maritza and NEK signed an agreement to reschedule payments of the overdue balance as of the agreement date. By December

2014, NEK has fulfilled its payment obligations under the agreement. On July 31, 2014, Maritza entered into a tripartite agreement with NEK and Mini Maritza Iztok EAD (MMI), our fuel supplier, which reduced Maritza's outstanding receivables from NEK by $17 million through an offset of payables due by Maritza to MMI. Additionally, NEK agreed to four additional monthly installments totaling $28 million to be paid equally from August to November 2014, which NEK made accordingly. As of December 31, 2014, Maritza had an outstanding receivables balance of $262 million including $57 million of current receivables, $75 million of receivables overdue by less than 90 days and $130 million of receivables overdue by more than 90 days. See Key Trends and Uncertainties, Macroeconomics, Bulgaria in Item 7—Management Discussion and Analysis to this Form 10-K for further information.

On February 18, 2014, Standard & Poor's lowered NEK's credit rating from BB- to B+ with a negative outlook. This credit rating is lower than the rating NEK had of BB upon the issuance of the Government Support Letter in 2005. Given the credit rating lowered, the PPA could be terminated at the discretion of Maritza and the lenders. Also, as a result of the restructuring, SEWRC revoked NEK's transmission license. These events trigger a cross default under the project debt agreements. 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 following:

- Availability of the operating units
- Level of wind resource for St. Nikola
- 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 SEM for the businesses located in Northern Ireland (1,908 MW). During 2014, AES sold its interests in four wind generation facilities totaling 87.5 MW located in Scotland and England which operated in the UK wholesale electricity market. AES is still continuing to develop a wind pipeline of approximately 250 MW in Scotland.

The Northern Ireland generation facilities consist of two plants within the Belfast region. Our Kilroot plant is a 662 MW coal-fired plant 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 capacity payments offered through the SEM Capacity Payment Mechanism, 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). In addition to the above, value is also secured from ancillary services.

Ballylumford is partially contracted for 600 MW under a PPA with NIE that expires in 2018, with an extension at the offtaker’s option through 2023, with the remaining capacity bid into the SEM market. The Ballylumford B station of 540 MW will not meet the standards of the EU Industrial Emission Directive following 2015. AES has secured a Local Reserve Services Agreement with the Transmission System Operator to refurbish two thermal units at the B station to provide at least 250 MW of capacity in the period 2016 to 2018 with an option to extend out to 2020.

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.

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 two largest 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 dispatched based on merit order.

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 IED that establishes the ELV for SO_2, NO_x and dust emissions to be complied with starting in 2016. This affects our Kilroot business which currently complies with the dust ELV, but for the SO_2, and particularly NO_x, significant investment will be required to be in compliance.

The IED provides for two options that may be implemented by the EU member states – TNP or Limited Life Time Derogation ("LLTD"). The TNP would allow the power plants to continue to operate between 2016-2020, being exempt from compliance with ELVs, but observing a ceiling set for maximum annual emissions that is established by looking at the last 10 years average emissions and operating hours. Under the TNP, power plants will have to implement investment plans that will ensure compliance by 2020. The LLTD will allow plants to run between 2016-2023, being exempt from the compliance with ELVs but for no more than 17,500 hours. Kilroot has elected the TNP as it gives the business significant operating flexibility without further investment. We are also reviewing the commercial positioning of the Kilroot business and the financial value that could be derived out of making the plant fully compliant with IED ELV's post-2016. As of the end of 2014, favorable commodity pricing is supportive of this investment and we will be performance testing new low NO_X technology in the second quarter of 2015. An investment of approximately $10 million is required to implement the TNP.

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 4% of the total annual generation in Kazakhstan. Of the total capacity of 2,688 MW, 1,033 MW is hydroelectric and operates under a concession agreement until the beginning of October 2017 and 1,655 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 2012 amendments to the Electricity Law state that a centrally organized capacity market will be established by 2016, 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). These sales could be considered as contracted, since Ust Kamenogorsk Heat Nets has no alternative suppliers.

Market Structure. The Kazakhstan electricity market totals approximately 20,591 MW, of which 17,108 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 $24 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 2009-2015 for each of the thirteen 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 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.

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, the 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, the following, and 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
- Regulated heat tariff levels
- Weather conditions

Other Europe Businesses

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

In the Netherlands, we own 50% of the Elsta facility, a 630 MW gas-fired plant that supplies steam and electricity under long-term contracts ending in 2018. Elsta's income is reported as Equity in Earnings of Affiliates in our consolidated results of operations.

In November 2014, AES sold its 95% ownership in a 294 MW gas-fired Ebute power plant in Nigeria to Cryex Energy Limited. The plant operated under a capacity-based PPA contract with the state-owned entity Power Holding Company of Nigeria ("PHCN"), which expired in November 2014. See Note 24—Dispositions included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information.

In December 2014, AES sold its 49.62% ownership of 364 MW of hydroelectric and gas-fired plants in Turkey to its partner Koc Holdings. The Turkey hydro businesses were under the renewable feed-in tariff, while the gas assets were dispatched in the market. Our businesses in Turkey were operated under a joint venture structure and reported as Equity in Earnings of Affiliates. See Note 8—Investments in and Advances to Affiliates included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information.

Asia SBU

Our Asia SBU has generation facilities in four countries. Our Asia operations accounted for 2%, 5% and 7% of AES consolidated Operating Margin and 2%, 8% and 10% of AES consolidated Adjusted PTC (a non-GAAP measure) in 2014, 2013 and 2012, respectively. The percentages reflect the contribution by our Asia SBU to gross Operating Margin and Adjusted PTC before deductions for Corporate.

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The following table provides highlights of our Asia operations:

Countries	India, Philippines, Sri Lanka and Vietnam
Generation Capacity	1,218 gross MW (678 proportional MW)
Generation Facilities	5 (including 2 under construction)
Key Businesses	Masinloc, OPGC I and Mong Duong II

Operating installed capacity of our Asia SBU totals 1,218 MW. Set forth 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					
Kelanitissa	Sri Lanka	Diesel	168	90	%	2003	2023	Ceylon Electricity Board
Sri Lanka Subtotal			168					
Asia Total			1,218					

(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			
Mong Duong II	Vietnam	Coal	1,240	51	%	2H 2015
Vietnam Subtotal			1,240			
Asia Total			2,560			

The following map illustrates the location of our Asia facilities:

Asia Businesses
Philippines
Business Description. The Masinloc power project in Philippines is a 630 (gross) MW coal-fired plant located in Masinloc, 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 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 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.
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) is interconnected with Visayas and represents 88% of the total demand of both regions. Luzon and Visayas together have an installed capacity of 14,732 MW.
There is diversity in the mix of the Luzon - Visayas generation, with coal accounting for 38%, natural gas for 22%, hydroelectric for 18%, geothermal generation for 4%, and the remaining 18% from other generating plants such as oil (dispatched during emergencies or during peak demand), wind, biomass, and solar (priority dispatch with feed-in tariff).
The primary customers for electricity are private distribution utilities, electric cooperatives, and to a lesser extent large industrial customers. Approximately 90%-95% of the system's total energy requirement is being sold/purchased through medium (3-5 years) to long (6-10 years) term bilateral contracts. The remaining 5%-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.
Regulatory Framework
Electricity Regulation. The Philippines has divided its power sector into generation, transmission, distribution and supply under the EPIRA. 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-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 ERC-approved bilateral contract rates, including WESM purchases.
Other Regulatory Considerations. Pursuant to EPIRA, the RC&OA 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 1,000 kW), 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 sells to two contestable customers.
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 the current draft of the Renewable Portfolio Standard of the law, certain customers (e.g. distribution utilities and retail electricity

suppliers) will be required to source certain percentage of their supply from eligible renewable energy sources. The National Renewable Energy Board ("NREB") is currently developing the 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.

Key Financial Drivers

Key financial drivers include, but are not limited to, the following:

- Availability - Masinloc carries the risk of providing replacement power to its customers whenever its availability is lower than the outage allowance provided for in the contracts
- Regulatory - ERC intervention in the spot market could result in lower spot prices, and the ongoing review of Masinloc's power supply contract with electric cooperatives could result in lower approved rates
- Fuel costs - higher coal prices decrease margins on spot sales
- Spot prices - high spot prices can positively impact the performance of the business when excess capacity is available to sell into the spot market and negatively impact the business when it is required to buy replacement power due to outages outside of the contractual allowance, while low spot prices decrease margins from sales of excess energy (mostly post-2017 due to contracted level at the business)

India

Business Description. Our generation business in India consists of the 420 MW coal-fired OPGC located in the State of Odisha as well as a collocated construction project. AES acquired 49% of OPGC in 1998, with the remaining 51% owned by the state.

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 in Equity in Earnings of Affiliates in our consolidated results of operations.

Construction and Development

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, 2014, total capitalized costs at the project level were $186 million (AES share of $91 million), while at the AES level capitalized costs were $10 million. 50% of the expansion capacity is contracted with the state offtaker, GRIDCO, for a period of 25 years, with a guaranteed after-tax rate of return of 16%. 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 long-term competitively bid Power Purchase Agreements and in the Indian merchant market.

In August 2014, the Supreme Court of India invalidated the allocation of coal blocks to companies with certain levels of private ownership. OPGC is currently pursuing another avenue of obtaining a long-term coal source.

Vietnam

Business Description. The Mong Duong II power project is a 1,240 MW plant being constructed under a BOT agreement in Quang Ninh province of Vietnam. The project is currently the largest private sector power project in the country. AES-VCM Mong Duong Power Company Limited ("the BOT Company") is a limited liability joint venture established by the affiliates of AES (51%), Posco Energy Corporation (30%) and China Investment Corporation (19%). The BOT Company has a PPA term of 25 years with EVN. At the end of the term of the PPA, the BOT Company will be transferred to the Vietnamese Government in accordance with the BOT contract. Upon reaching commercial operations, EVN will have exclusive rights on the facility's entire capacity and energy. Vinacomin, a state-owned entity, is the project's coal supplier under a 25-year coal supply agreement.

The tariff has two components: i) the Capacity charge and the foreign component of O&M charge, which are paid in U.S. Dollars, and ii) the local component of O&M and fuel charge, which are paid in Vietnam Dong. In addition, the U.S. Dollar and Vietnam Dong components of O&M are linked to a published Consumer Price Index of the U.S. and Vietnam, respectively. Fuel costs in general are pass-through elements in the fuel charge.

The project is currently under construction and is scheduled to commence full operations in the second half of 2015.

Financial Data by Country

See the table with our consolidated operations for each of the three years ended December 31, 2014, 2013 and 2012, and property, plant and equipment as of December 31, 2014 and 2013, by country, in Note 17— Segments 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 United States 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. 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, including a NOV issued by the EPA against IPL concerning new source review and prevention of significant deterioration issues under the CAA.

United States Environmental and Land-Use Legislation and Regulations

In the United States 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 will be implemented, in part, through a market-based program under which compliance may be achievable through the acquisition and use of new emissions allowances that the EPA will create. The CSAPR contemplates limited interstate and intra-state trading of emissions allowances by covered sources. Initially, the EPA will issue emissions allowances to affected power plants based on state emissions budgets established by the EPA under the CSAPR. The future availability of and cost to purchase allowances to meet the emission reduction requirements is uncertain at this time.

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

- January 1, 2015: Phase 1 (2015 and 2016) begins for annual trading programs. Existing units must begin monitoring and reporting SO_2 and NO_x emissions.
- May 1, 2015: Phase 1 begins for ozone-season NO_x trading program. Existing units must begin 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 Company will be required to comply with the CSAPR in several states, including Ohio and Indiana. We cannot predict at this time the impact that implementation of the CSAPR will have on the Company but note that the current, state-wide emissions in the states in which the Company's subsidiaries operate are below the CSAPR budgets for Phase 1. Nonetheless, in the future certain of the Company's subsidiaries could be required to increase their capital expenditures and face increasing compliance costs to fully comply with the CSAPR, which expenditures and costs could be material.

MATS. The EPA is obligated under Section 112 of the CAA to develop a rule requiring pollution controls for hazardous air pollutants, including mercury, hydrogen chloride, hydrogen fluoride, and nickel species, among other substances, from coal and oil-fired power plants. In connection with such rule, the CAA requires the EPA to establish MACT. MACT is defined as the emission limitation achieved by the "best performing 12%" of sources in the source category. Pursuant to Section 112 of the CAA, the EPA promulgated a final rule on December 16, 2011, called the MATS establishing National Emissions Standards for Hazardous Air Pollutants from coal and oil-fired electric utility steam generating units. These emission standards reflect the EPA's application of MATS for each pollutant regulated under the rule. The rule requires 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 United States coal-fired plants operated by the Company's subsidiaries have scrubbers or comparable control technologies designed to remove SO_2 and which also remove some acid gases. However, there are other improvements to such control technologies that may be needed even at these plants to assure compliance with the MATS standards. Older coal-fired facilities that do not currently have a SO_2 scrubbers installed are particularly at risk. 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 estimates additional expenditures related to the MATS rule for environmental controls for its baseload generating units to be approximately $511 million through 2016, excluding demolition costs. In August 2013, the IURC approved IPL's MATS petition and request for a Certificate of Public Convenience and Necessity for this amount (including supplemental testimony). These filings detail the installations of new pollution control equipment that IPL plans to add to its five largest baseload generating units. The IURC also approved, with certain stipulations, IPL's request to recover through its environmental rate adjustment mechanism all operating and capital expenditures (including a return) related to compliance. Recovery of these costs is through an Indiana statute that allows for 100% recovery of qualifying costs through a rate adjustment mechanism. As part of its Order, the IURC stipulated that if IPL's Harding Street unit is retired before IPL has fully depreciated the new controls (which have a 20-year depreciable life), IPL shall not continue to collect depreciation expense on the clean energy projects included in the MATS Order for that unit. IPL management is currently evaluating the impact of this recent Order.

Several lawsuits challenging the MATS rule were filed 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, a three-judge panel of the D.C. Circuit denied the challenges. On November 25, 2014, the U.S. Supreme Court granted certiorari in several petitions for review of the D.C. Circuit's decision. The U.S. Supreme Court is expected to review the case by July 2015. It is difficult to predict the outcome of this litigation, or its impact, if any, on our MATS compliance planning.

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 our U.S. utilities, DP&L and IPL, the utilities would seek recovery of any operating or capital expenditures related to air pollution control technology to reduce regulated air emissions; however, there can be no assurances that they would be successful in that regard.

Regional Haze Rule. In July 1999, the EPA published the "Regional Haze Rule" to reduce haze and protect visibility in designated federal areas. On June 15, 2005, the EPA proposed amendments to the Regional Haze Rule that set guidelines for determining BART at affected plants and how to demonstrate "reasonable progress" towards eliminating man-made haze by 2064. The amendment to 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 stayed while challenges to the CSAPR in the D.C. Circuit proceed, because vacatur of the CSAPR would effectively vacate EPA's actions related to BART.

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, the PSD program. 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 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.

The EPA proposed a rule establishing NSPS for new electric generating units on January 8, 2014. The proposed NSPS would establish CO_2 standards of 1100 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 also would impose standards of 1000 lbs/MWh for large NGCC facilities and 1100 lbs/MWh for smaller and peaking NGCC facilities. These standards would apply to any electric generating unit with construction commencing after January 8, 2014. The EPA is expected to issue the final NSPS during the summer of 2015. The Company cannot predict whether these standards will be changed prior to the rule becoming final but the NSPS could have an impact on the Company's plans to construct and/or reconstruct electric generating units in some locations.

The EPA issued proposed rules requiring states to establish GHG performance standards for existing power plants under Clean Air Act Section 111(d) on June 2, 2014. Under the proposed rule, called the Clean Power Plan (the "CPP"), states would be required to meet state-wide emission rate standards averaged across all fossil-fuel fired generation in the state. The requirements would begin in 2020 and would become increasingly stringent through 2030, with the goal being a 30% reduction in total U.S. power sector emissions from 2005 levels by 2030. The proposed

CPP requires states to submit implementation plans to meet the standards set forth in the rule by June 30, 2016, with the possibility of one or two-year extensions under certain circumstances. The EPA also plans to propose a federal plan for meeting such standards, which states could adopt rather than developing their own state plans. The EPA is expected to finalize the rule in late summer 2015. Among other things, the Company's U.S.-based businesses could be required to make efficiency improvements to existing facilities. The EPA also issued proposed carbon pollution standards for modified and reconstructed power plants on June 2, 2014, which are also expected to be finalized this summer. However, it is too soon to determine what the CPP, and rules for modified and reconstructed power plants, and the corresponding state implementation plans for existing facilities affecting the Company’s U.S.-based businesses, will require once they are finalized, whether they will survive judicial and other challenges that have been commenced, and if so, whether and when the rule and the corresponding state implementations plan would materially impact the Company’s business, operations or financial condition.

Cooling Water Intake. The Company's facilities are subject to a variety of rules governing water discharges. In particular, the Company's U.S. facilities are subject to the CWA Section 316(b) rule issued by the EPA which seeks to protect fish and other aquatic organisms by requiring existing steam electric generating facilities to utilize the BTA for cooling water intake structures. On August 15, 2014, the EPA published its final standards to protect fish and other aquatic organisms drawn into cooling water systems at large power plants and other industrial facilities. These standards require subject facilities that utilize at least 25% of the withdrawn water exclusively for cooling purposes and have a design intake flow of greater than two million gallons per day to choose among seven BTA options to reduce fish impingement. In addition, facilities that withdraw at least 125 million gallons per day for cooling purposes must conduct studies to assist permitting authorities to determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms. This decision 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.

At this time, it is contemplated that the Company's Redondo Beach, Huntington Beach and Alamitos power plants in California (collectively, "AES Southland") will need to have in place BTA by December 31, 2020, or repower the facilities. On April 1, 2011, AES Southland filed an Implementation Plan with the State Water Resources Control Board that indicated its intent to repower the facilities in a phased approach, with the final units being in compliance by 2024. The State Water Resources Board is currently reviewing the implementation plans and has requested additional information to assist with its evaluation. Power plants will be required to comply with the more stringent of state or federal requirements. At present, the Company cannot predict whether the federal EPA or California state requirements will be the more stringent and therefore applicable, but the Company anticipates compliance costs could 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 United States under the CWA. In June 2014, the EPA along with the U.S. Army Corps of Engineers issued a proposed rule defining the waters of the United States. This rulemaking has the potential to impact all programs under the CWA. Expansion of regulated waterways is possible based on initial review of the proposal, which may impact several permitting programs. Although we cannot at this time determine the timing or impact of compliance with any new regulations, more stringent regulations could have a material impact on our operations and/or consolidated financial results.

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 2015. 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 levels of acceptable metal effluent water discharge, 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 2017 for IPL’s Harding Street and Petersburg facilities through agreed orders with IDEM. IPL conducted studies to determine what operational changes and/or additional equipment will be required to comply with the new limitations. In October 2014, IPL filed its wastewater compliance plans for its power plants with the IURC. IPL is seeking approval for a CPCN for the installation and operation of wastewater treatment technologies at IPL's Petersburg Plant and Harding Street Station, as well as the refueling of Harding Street Unit 7 from coal to natural gas (about 410 MW net capacity). If approved, IPL will invest $332 million in these projects to ensure compliance with the wastewater treatment requirements by 2017. IPL expects to recover through its environmental rate adjustment mechanism, operating or capital expenditures related to compliance with these NPDES permit 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 permit requirements on our consolidated results of operations, cash flows, or financial condition, but it is expected to be material.

In June 2013, the EPA proposed rules to reduce toxic pollutants discharged into waterways by power plants. The proposed rules are intended to update the existing technology-based rules for controlling the discharge of pollutants from various waste streams associated with steam electric generating facilities. The proposed rules identify four preferred options for controlling the discharge of these pollutants, and the EPA believes that over half of existing power plants will comply with these rules, if they become final, without incurring costs. However, it is too early to determine whether the impacts of this rule, if and when it becomes final, will materially impact the Company or its subsidiaries. The EPA is required to finalize these rules by September 30, 2015.

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 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. In December 2014, the EPA adopted a final rule regulating CCR under Subtitle D of the Resource Conservation and Recovery Act. The final rule, expected to become effective in the summer of 2015, establishes nationally applicable minimum criteria for the disposal of CCR in new and currently operating landfills and surface impoundments. The rule addresses location restrictions, liner design criteria, structural integrity requirements, operating criteria, groundwater monitoring and corrective action requirements, closure and post-closure care requirements, and record keeping, notification, and internet posting requirements. 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 which, 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 sets forth 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 PRPs have sued DP&L and other unrelated entities seeking a contribution towards 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 $626 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 is expected to be completed in 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.

As a result of existing and expected environmental regulations, including MATS, DP&L notified PJM that it plans 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 are scheduled to retire 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 United States, 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 2014 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, 2014, we employed approximately 18,500 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, 51 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 Dayton 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 Degree distinction in Business Management and Finance, and an MBA with Cum Laude distinction from Universidad José Maria Vargas.

Andrés R. Gluski, 57 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 is also Chairman of AES Gener since 2005 and AES Brasiliana since 2006 and served on the Board of AES Entek, a joint venture between AES and Koc Holdings in Turkey. Mr. Gluski is also on the Boards of Waste Management, Inc., The Council of Americas, The Edison Electric Institute, and the U.S.-Brazil CEO Forum. In 2013, President Obama appointed Mr. Gluski to the President's Export Council. 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, 53 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 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. Indianapolis Power & Light and its parent company IPALCO, AES Sul and AES Chivor. She also serves as a Director on the Greater Washington Board of Trade and is a Strategic Advisor to the Paladin Group. Ms. Hackenson earned her degree from New York State University.

Tish Mendoza, 39 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 AES Panamá, S.A., 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, 49 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. In November of 2011, Mr. Miller joined the Board of DP&L and its parent company, DPL, Inc. and is also a member of the Board of 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, 55 years old, has served as EVP and CFO of the Company since September of 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 serves as a member of the Boards of AES Gener, 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 16, 2014.

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, 2014, we had approximately $20.9 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, 2014, we had approximately $20.9 billion of outstanding indebtedness on a consolidated basis, of which approximately $5.3 billion was recourse debt of The AES Corporation and approximately $15.6 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 $0.9 billion as of December 31, 2014. 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;
- 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

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- 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 of 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 in addition to other factors described below. Consequently, any changes in the supply and cost of coal, natural gas, or oil 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 United States 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 United States 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 Information 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 set forth 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 this 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;
- high inflation and monetary fluctuations;
- restrictions on imports of coal, oil, gas or other raw materials required by our generation businesses to operate;
- threatened or consummated expropriation or nationalization of our assets by foreign governments;
- risks relating to the failure to comply with the U.S. Foreign Corrupt Practices Act, United Kingdom Bribery Act or other anti-bribery laws applicable to our operations;
- difficulties in hiring, training and retaining qualified personnel, particularly finance and accounting personnel with GAAP expertise;
- unwillingness of governments, government agencies, similar organizations or other counterparties to honor their contracts;
- unwillingness of governments, government agencies, courts or similar bodies to enforce contracts that are economically advantageous to subsidiaries of the Company and economically unfavorable to counterparties, against such counterparties, whether such counterparties are governments or private parties;
- inability to obtain access to fair and equitable political, regulatory, administrative and legal systems;
- adverse changes in government tax policy;
- difficulties in enforcing our contractual rights or enforcing judgments or obtaining a favorable result in local jurisdictions; and
- potentially adverse tax consequences of operating in multiple jurisdictions.

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

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

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

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

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

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

As a result of the above risks and other potential hazards associated with the power generation, distribution and transmission industries, we may from time to time become exposed to significant liabilities for which we may not have adequate risk mitigation and/or insurance coverage. Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of rotating equipment and delivering electricity to transmission and distribution systems. In addition to natural risks, such as earthquakes, floods, lightning, hurricanes and wind, hazards, such as fire, explosion, collapse and machinery failure, are inherent risks in our operations which may occur as a result of inadequate internal processes, technological flaws, human error or actions of third parties or other external events. The control and management of these risks depend upon adequate development and training of personnel and on the existence of operational procedures, preventative maintenance plans and specific programs supported by quality control systems which reduce, but do not eliminate, the possibility of the occurrence and impact of these risks.

The hazards described above, along with other safety hazards associated with our operations, can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being named as a defendant in lawsuits asserting claims for substantial damages, environmental cleanup costs, personal injury and fines and/or penalties. We maintain an amount of insurance protection that we believe is customary, but there can be no assurance that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. A claim for which we are not fully insured or insured at all could hurt our financial results and materially harm our financial condition. Further, due to the cyclical nature of the insurance markets, we cannot provide assurance that insurance coverage will continue to be available on terms similar to those presently available to us or at all. Any losses not covered by insurance could have a material adverse effect on our financial condition, results of operations or cash flows.

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

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

Our inability to attract and retain skilled people could have a material adverse effect on our operations.

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

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

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

prices may not be favorable and thus could increase our operating costs.
We may not be able to enter into long-term contracts, which reduce volatility in our results of operations. Even when we successfully enter into long-term contracts, our generation businesses are often dependent on one or a limited number of customers and a limited number of fuel suppliers.
Many of our generation plants conduct business under long-term sales and supply contracts, which helps these businesses to manage risks by reducing the volatility associated with power and input costs and providing a stable revenue and cost structure. In these instances, we rely on power sales contracts with one or a limited number of customers for the majority of, and in some cases all of, the relevant plant's output and revenues over the term of the power sales contract. The remaining terms of the power sales contracts of our generation plants range from one to 25 years. In many cases, we also limit our

exposure to fluctuations in fuel prices by entering into long-term contracts for fuel with a limited number of suppliers. In these instances, the cash flows and results of operations are dependent on the continued ability of customers and suppliers to meet their obligations under the relevant power sales contract or fuel supply contract, respectively. Some of our long-term power sales agreements are at prices above current spot market prices and some of our long-term fuel supply contracts are at prices below current market prices. The loss of significant power sales contracts or fuel supply contracts, or the failure by any of the parties to such contracts that prevents us from fulfilling our obligations thereunder, could adversely impact our strategy by resulting in costs that exceed revenue, which could have a material adverse impact on our business, results of operations and financial condition. In addition, depending on market conditions and regulatory regimes, it may be difficult for us to secure long-term contracts, either where our current contracts are expiring or for new development projects. The inability to enter into long-term contracts could require many of our businesses to purchase inputs at market prices and sell electricity into spot markets, which may not be favorable.

We have sought to reduce counterparty credit risk under our long-term contracts in part by entering into power sales contracts with utilities or other customers of strong credit quality and by obtaining guarantees from certain sovereign governments of the customer’s obligations. However, many of our customers do not have, or have failed to maintain, an investment-grade credit rating, and our generation business cannot always obtain government guarantees and if they do, the government does not always have an investment grade credit rating. We have also sought to reduce our credit risk by locating our plants in different geographic areas in order to mitigate the effects of regional economic downturns. However, there can be no assurance that our efforts to mitigate this risk will be successful.

Competition is increasing and could adversely affect us.

The power production markets in which we operate are characterized by numerous strong and capable competitors, many of whom may have extensive and diversified developmental or operating experience (including both domestic and international) and financial resources similar to or greater than ours. Further, in recent years, the power production industry has been characterized by strong and increasing competition with respect to both obtaining power sales agreements and acquiring existing power generation assets. In certain markets, these factors have caused reductions in prices contained in new power sales agreements and, in many cases, have caused higher acquisition prices for existing assets through competitive bidding practices. The evolution of competitive electricity markets and the development of highly efficient gas-fired power plants have also caused, or are anticipated to cause, price pressure in certain power markets where we sell or intend to sell power. These competitive factors could have a material adverse effect on us.

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

Certain of our subsidiaries have defined benefit pension plans covering substantially all of their respective employees. Of the thirty one defined benefit plans, five are at United States subsidiaries and the remaining plans are at foreign subsidiaries. Pension costs are based upon a number of actuarial assumptions, including an expected long-term rate of return on pension plan assets, the expected life span of pension plan beneficiaries and the discount rate used to determine the present value of future pension obligations. Any of these assumptions could prove to be wrong, resulting in a shortfall of pension plan assets compared to pension obligations under the pension plan. The Company periodically evaluates the value of the pension plan assets to ensure that they will be sufficient to fund the respective pension obligations. The Company’s exposure to market volatility is mitigated to some extent due to the fact that the asset allocations in our largest plans include a significant weighting of investments in fixed income securities that are less volatile than investments in equity securities. Future downturns in the debt and/or equity markets, or the inaccuracy of any of our significant assumptions underlying the estimates of our subsidiaries’ pension plan obligations, could result in an increase in pension expense and future funding requirements, which may be material. Our subsidiaries who participate in these plans are responsible for satisfying the funding requirements required by law in their respective jurisdiction for any shortfall of pension plan assets compared to pension obligations under the pension plan. This may necessitate additional cash contributions to the pension plans that could adversely affect the Parent Company and our subsidiaries’ liquidity.

For additional information regarding the funding position of the Company’s pension plans, see Item 7.—Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Estimates—Pension and Postretirement Obligations and Note 15—Benefit Plans included in Item 8.—Financial Statements and Supplementary Data included in this Form 10-K.

Our business is subject to substantial development uncertainties.

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

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

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

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

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

The AES Corporation entered into a Shareholders Agreement with Terrific Investment Corporation ("Investor"), a subsidiary of China Investment Corporation, in connection with the purchase of shares from AES in 2010. The Shareholders Agreement provides Investor with certain rights, including, without limitation, the right to nominate a Director to the Board of The AES Corporation, registration rights for the shares held by Investor, including demand registration rights and piggyback registration rights. Further information regarding the Shareholders Agreement can be found in the agreement itself, which is filed as an exhibit to this Form 10-K. In December of 2013, Terrific sold a significant percentage of its holdings, though it continues to hold over 8% of the Company’s outstanding shares. In the event that Terrific determines to sell additional shares of the Company, there could be a material impact on our share price.

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

Wind Generation, our solar projects and our investments in projects such as energy storage are subject to substantial risks. Projects of this nature have been developed through advancement in technologies which may not be proven or whose commercial application is limited, and which are unrelated to our core business. Some of these business lines are dependent upon favorable regulatory incentives to support continued investment, and there is significant uncertainty about the extent to which such favorable regulatory incentives will be available in the future. Furthermore, production levels for our wind and solar projects may be dependent upon adequate wind or sunlight resulting in volatility in production levels and profitability. For example, for our wind projects, wind resource estimates are based on historical experience when available and on wind resource studies conducted by an independent engineer, and are not expected to reflect actual wind energy production in any given year.

As a result, these types of renewable energy projects face considerable risk relative to our core business, including the risk that favorable regulatory regimes expire or are adversely modified. In addition, because certain of these projects depend on technology outside of our expertise in generation and utility businesses, there are risks associated with our ability to develop and manage such projects profitably. Furthermore, at the development or acquisition stage, because of the nascent nature of these industries or the limited experience with the relevant technologies, our ability to predict actual performance results may be hindered and the projects may not perform as predicted. There are also risks associated with the fact that some of these projects exist in markets where long-term fixed price contracts for the major cost and revenue components may be unavailable, which in turn may result in these projects having relatively high levels of volatility. Even where available, many of our renewable projects sell power under a Feed-in-Tariff, which may be eliminated or reduced, which can impact the profitability of these projects, or make money through the sale of Emission Reductions products, such as Certified Emissions Reductions, Renewable Energy Certificates or Renewable Obligation Certificates, and the price of these products may be volatile.

These projects can be capital-intensive and generally are designed with a view to obtaining third party financing, which may be difficult to obtain. As a result, these capital constraints may reduce our ability to develop these projects or obtain third party financing for these projects. These risks may be exacerbated by the current global economic crisis, including our management's increased focus on liquidity, which may also result in slower growth in the number of projects we can pursue. The economic downturn could also impact the value of our assets in these countries and our ability to develop these projects. If the value of these assets decline, this could result in a material impairment or a series of impairments which are material in the aggregate, which would adversely affect our financial statements.

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

As of December 31, 2014, the Company had approximately $1.5 billion of goodwill, which represented approximately 3.7% of the total assets on its Consolidated Balance Sheets. Goodwill is not amortized, but is evaluated for impairment at least annually, or more frequently if impairment indicators are present. We could be required to evaluate the potential impairment of goodwill outside of the required annual evaluation process if we experience situations, including but not limited to: deterioration in general economic conditions, or our operating or regulatory environment; increased competitive environment; increase in fuel costs, particularly when we are unable to pass through the impact to customers; negative or declining cash flows; loss of a key contract or customer, particularly when we are unable to replace it on equally favorable terms; divestiture of a significant component of our business; or adverse actions or assessments by a regulator. These types of events and the resulting analyses could result in goodwill impairment, which could substantially affect our results of operations for those periods. Additionally, goodwill may be impaired if our acquisitions do not perform as expected. See the risk factor Our acquisitions may not perform as expected for further discussion.

Long-lived assets are initially recorded at fair value and are amortized or depreciated over their estimated useful lives. Long-lived assets are evaluated for impairment only when impairment indicators are present whereas goodwill is evaluated for impairment on an annual basis or more frequently if potential impairment indicators are present. Otherwise, the recoverability assessment of long-lived assets is similar to the potential impairment evaluation of goodwill particularly as it relates to the identification of potential impairment indicators, and making estimates and assumptions to determine fair value, as described above.

Certain of our businesses are sensitive to variations in weather.

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

In addition, we are dependent upon hydrological conditions prevailing from time to time in the broad geographic regions in which our hydroelectric generation facilities are located. If hydrological conditions result in droughts or other conditions that negatively affect our hydroelectric generation business, our results of operations could be materially adversely affected.

Information security breaches could harm our business.

A security breach of our information technology systems or plant control systems used to manage and monitor operations could impact the reliability of our generation fleets and/or the reliability of our transmission and distribution systems. A security breach that impairs our technology infrastructure could disrupt normal business operations and affect our ability to control our transmission and distribution assets, access customer information and limit our communications with third parties. Our security measures may not prevent such security breaches. Any loss of confidential or proprietary data through a breach could impair our reputation, expose us to legal claims, or impact our ability to make collections or otherwise impact our operations, and materially adversely affect our business and results of operations.

Our acquisitions may not perform as expected.

Historically, acquisitions have been a significant part of our growth strategy. We may continue to grow our business through acquisitions. Although acquired businesses may have significant operating histories, we will have a limited or no history of owning and operating many of these businesses and possibly limited or no experience operating in the country or region where these businesses are located. Some of these businesses may have been government owned and some may be operated as part of a larger integrated utility prior to their acquisition. If we were to acquire any of these types of businesses, there can be no assurance that:

- we will be successful in transitioning them to private ownership;
- such businesses will perform as expected;
- integration or other one-time costs will not be greater than expected;
- we will not incur unforeseen obligations or liabilities;
- such businesses will generate sufficient cash flow to support the indebtedness incurred to acquire them or the capital expenditures needed to develop them; or
- the rate of return from such businesses will justify our decision to invest capital to acquire them.

Risks associated with Governmental Regulation and Laws

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

Our inability to predict, influence or respond appropriately to changes in law or regulatory schemes, including any inability to obtain expected or contracted increases in electricity tariff or contract rates or tariff adjustments for increased expenses, could adversely impact our results of operations or our ability to meet publicly announced projections or analysts' expectations. Furthermore, changes in laws or regulations or changes in the application or interpretation of regulatory provisions in jurisdictions where we operate, particularly at our utilities where electricity tariffs are subject to regulatory review or approval, could adversely affect our business, including, but not limited to:

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

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

In many countries where we conduct business, the regulatory environment is constantly changing and it may be difficult to predict the impact of the regulations on our businesses. On July 21, 2010, President Obama signed the Dodd-Frank Act. While the bulk of regulations contained in the Dodd-Frank Act regulate financial institutions and their products, there are several provisions related to corporate governance, executive compensation, disclosure and other matters which relate to public companies generally. The types of provisions described above are currently not expected to have a material impact on the Company or its results of operations. Furthermore, while the Dodd-Frank Act substantially expands the regulation regarding the trading, clearing and reporting of derivative transactions, the Dodd-Frank Act provides for commercial end-user exemptions which may apply to our derivative transactions. However, even with the exemption, the Dodd-Frank Act could still have a material adverse impact on the Company, as the regulation of derivatives (which includes capital and margin requirements for non-exempt companies), could limit the availability of derivative transactions that we use to reduce interest rate, commodity and currency risks, which would increase our exposure to these risks. Even if derivative transactions remain available, the costs to enter into these transactions may increase, which could adversely affect the operating results of certain projects; cause us to default on certain types of contracts where we are contractually obligated to hedge certain risks, such as project financing agreements; prevent us from developing new projects where interest rate hedging is required; cause the Company to abandon certain of its hedging strategies and transactions, thereby increasing our exposure to interest rate, commodity and currency risk; and/or consume substantial liquidity by forcing the Company to post cash and/or other permitted collateral in support of these derivatives. In addition to the Dodd-Frank Act, in 2012, the EMIR became effective. EMIR includes regulations related to the trading, reporting and clearing of derivatives and the impacts described above could also result from our (or our subsidiaries') efforts to comply with EMIR. It is also possible that additional similar regulations may be passed in other jurisdictions where we conduct business. Any of these outcomes could have a material adverse effect on the Company.

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

EPAct 2005 authorizes the FERC to remove the obligation of electric utilities under Section 210 of PURPA to enter into new contracts for the purchase or sale of electricity from or to QFs if certain market conditions are met. Pursuant to this authority, the FERC has instituted a rebuttable presumption that utilities located within the control areas of the Midwest Independent Transmission System Operator, Inc., PJM Interconnection, L.L.C., ISO New England, Inc., the NYISO and the Electric Reliability Council of Texas, Inc. are not required to purchase or sell power from or to QFs above a certain size. In addition, the FERC is authorized under EPAct 2005 to remove the purchase/sale obligations of individual utilities on a case-by-case basis. While this law does not affect existing contracts, as a result of the changes to PURPA, our QFs may face a more difficult market environment when their current long-term contracts expire.

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

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

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

FERC has civil penalty authority over violations of any provision of Part II of the FPA which concerns wholesale generation or transmission, as well as any rule or order issued thereunder. FERC is authorized to assess a maximum civil penalty of $1 million per violation for each day that the violation continues. The FPA also provides for the assessment of criminal fines and imprisonment for violations under the FPA. This penalty authority was enhanced in EPAct 2005. With this expanded enforcement authority, violations of the FPA and FERC's regulations could potentially have more serious consequences than in the past.

Pursuant to EPAct 2005, the NERC has been certified by FERC as the Electric Reliability Organization ("ERO") to develop mandatory and enforceable electric system reliability standards applicable throughout the United States to improve the overall reliability of the electric grid. These standards are subject to FERC review and approval. Once approved, the reliability standards may be enforced by FERC independently, or, alternatively, by the ERO and regional reliability organizations with responsibility for auditing, investigating and otherwise ensuring compliance with reliability standards, subject to FERC oversight. Monetary penalties of up to $1 million per day per violation may be assessed for violations of the reliability standards.

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

Our businesses are subject to stringent environmental laws and regulations.

Our businesses are subject to stringent environmental laws and regulations by many federal, regional, state and local authorities, international treaties and foreign governmental authorities. These laws and regulations generally concern emissions into the air, effluents into the water, use of water, wetlands preservation, remediation of contamination, waste disposal, endangered species and noise regulation, among others. Failure to comply with such laws and regulations or to obtain or comply with any necessary environmental permits pursuant to such laws and regulations could result in fines or other sanctions. Environmental laws and regulations affecting power generation and distribution are complex and have tended to become more stringent over time. Congress and other domestic and foreign governmental authorities have either considered or implemented various laws and regulations to restrict or tax certain emissions, particularly those involving air emissions and water discharges. See the various descriptions of these laws and regulations contained in Item 1.—Business of this Form 10-K. These laws and regulations have imposed, and proposed laws and regulations could impose in the future, additional costs on the operation of our power plants. We have incurred and will continue to incur significant capital and other expenditures to comply with these and other environmental laws and regulations. Changes in, or new, environmental restrictions may force the Company to incur significant expenses or expenses that may exceed our estimates. There can be no assurance that we would be able to recover all or any increased environmental costs from our customers or that our business, financial condition, including recorded asset values or results of operations, would not be materially and adversely affected by such expenditures or any changes in domestic or foreign environmental laws and regulations.

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

The EPA has pursued an enforcement initiative against coal-fired generating plants alleging wide-spread violations of the new source review and prevention of significant deterioration provisions of the CAA. The EPA has brought suit against a number of companies and has obtained settlements with many of these companies over such allegations. The allegations typically involve claims that a company made major modifications to a coal-fired generating unit without proper permit approval and without installing best available control technology. The principal, but not exclusive, focus of this EPA enforcement initiative is emissions of SO_2 and NO_X. In connection with this enforcement initiative, the EPA has imposed fines and required companies to install improved pollution control technologies to reduce emissions of SO_2 and NO_X. There can be no assurance that foreign environmental regulatory agencies in countries in which our subsidiaries operate will not pursue similar enforcement initiatives under relevant laws and regulations.

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

As discussed in Item 1.—Business, at the international, federal and various regional and state levels, rules are in effect and policies are under development to regulate GHG emissions, thereby effectively putting a cost on such emissions in order to create financial incentives to reduce them. In 2014, the Company's subsidiaries operated businesses which had total CO_2 emissions of approximately 78.7 million metric tonnes, approximately 41.6 million of which were emitted by businesses located in the United States (both figures ownership adjusted). The Company uses CO_2 emission estimation methodologies supported by "The Greenhouse Gas Protocol" reporting standard on GHG emissions. For existing power generation plants, CO_2 emissions data are either obtained directly from plant continuous emission monitoring systems or calculated from actual fuel heat inputs and fuel type CO_2 emission factors. The estimated annual CO_2 emissions from fossil fuel electric power generation facilities of the Company's subsidiaries that are in construction or development and have received the necessary air permits for commercial operations are approximately 12.5 million metric tonnes (ownership adjusted). This overall estimate is based on a number of projections and assumptions which may prove to be incorrect, such as the forecasted dispatch, anticipated plant efficiency, fuel type, CO_2 emissions rates and our subsidiaries' achieving completion of such construction and development projects. However, it is certain that the projects under construction or development when completed will increase emissions of our portfolio and therefore could increase the risks associated with regulation of GHG emissions. Because there is significant uncertainty regarding these estimates, actual emissions from these projects under construction or development may vary substantially from these estimates.

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

Foreign, federal, state or regional regulation of GHG emissions could have a material adverse impact on the Company's financial performance. The actual impact on the Company's financial performance and the financial performance of the Company's subsidiaries will depend on a number of factors, including among others, the degree and timing of GHG emissions reductions required under any such legislation or regulations, the cost of emissions reduction equipment and the price and availability of offsets, the extent to which market based compliance options are available, the extent to which our subsidiaries would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market and the impact of such legislation or regulation on the ability of our subsidiaries to recover costs incurred through rate increases or otherwise. As a result of these factors, our cost of compliance could be substantial and could have a material adverse impact on our results of operations.

In January 2005, based on European Community "Directive 2003/87/EC on Greenhouse Gas Emission Allowance Trading," the EU ETS commenced operation as the largest multi-country GHG emission trading scheme in the world. On February 16, 2005, the Kyoto Protocol became effective. The Kyoto Protocol requires all developed countries that have ratified it to substantially reduce their GHG emissions, including CO_2. To date, compliance with the Kyoto Protocol and the EU ETS has not had a material adverse effect on the Company's consolidated results of operations, financial condition and cash flows. The parties to the United Nations Framework Convention on Climate Change are continuing to work to reach an international agreement on GHG emissions to replace the Kyoto Protocol, which expired in 2012 but which is still observed by some countries. We cannot predict the impact of any such agreement, but it could have a material adverse effect on the Company's consolidated results of operations, financial condition and cash flows.

The United States has not ratified the Kyoto Protocol. In the United States, there currently is no federal legislation imposing a mandatory GHG emission reduction programs (including for CO_2) affecting the electric power generation facilities of the Company's subsidiaries. However, the EPA has adopted regulations pertaining to GHG emissions that require new sources of GHG emissions of over 100,000 tons per year, and existing sources planning physical changes that would increase their GHG emissions by more than 75,000 tons per year, to obtain new source review permits from the EPA prior to construction or modification. Additionally, the EPA has proposed a rule establishing New Source Performance Standards for CO_2 emissions for newly constructed fossil-fueled EUSGUs larger than 25 MW. The EPA has also proposed rules that would apply to modified or existing EUSGUs. Under the proposed rules, states would be judged against state-specific CO_2 emissions targets beginning in 2020, with expected total U.S. power sector emissions reduction of 30% from 2005 levels by 2030. The proposed rules requires states to implement plans to meet the standards or adopt a federal plan the EPA will propose. For further discussion of the regulation of GHG emission, see Item 1.—Business—Environmental and Land-Use Regulations—United States Environmental and Land-Use Legislation and Regulations—Greenhouse Gas Emissions above.

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

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

The regional auctions of RGGI allowances needed to be acquired by power generators to comply with state programs implementing RGGI occur approximately every quarter. Our subsidiary in Maryland is our only subsidiary that was subject to RGGI in 2014. Of the approximately 41.6 million metric tonnes of CO_2 emitted in the United States by our subsidiaries in 2014 (ownership adjusted), approximately 1.36 million metric tonnes were emitted by our subsidiary in Maryland. The Company estimates that the RGGI compliance costs could be approximately $3.4 million for 2015. There is a risk that our actual compliance costs under RGGI will differ from our estimates by a material amount and that our model could underestimate our costs of compliance.

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

Furthermore, according to the Intergovernmental Panel on Climate Change, physical risks from climate change could include, but are not limited to, increased runoff and earlier spring peak discharge in many glacier and snow-fed rivers, warming of lakes and rivers, an increase in sea level, changes and variability in precipitation and in the intensity and frequency of extreme weather events. Physical impacts may have the potential to significantly affect the Company's business and operations, and any such potential impact may render it more difficult for our businesses to obtain financing. For example, extreme weather events could result in increased downtime and operation and maintenance costs at the electric power generation facilities and support facilities of the Company's subsidiaries. Variations in weather conditions, primarily temperature and humidity also would be expected to affect the energy needs of customers. A decrease in energy consumption could decrease the revenues of the Company's subsidiaries. In addition, while revenues would be expected to increase if the energy consumption of customers increased, such increase could prompt the need for additional investment in generation capacity. Changes in the temperature of lakes and rivers and changes in precipitation that result in drought could adversely affect the operations of the fossil fuel-fired electric power generation facilities of the Company's subsidiaries. Changes in temperature, precipitation and snow pack conditions also could affect the amount and timing of hydroelectric generation.

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

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

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

Our subsidiaries have operations in the United States and various non-United States jurisdictions. As such, we are subject to the tax laws and regulations of the United States federal, state and local governments and of many non-United States jurisdictions. From time to time, legislative measures may be enacted that could adversely affect our overall tax positions regarding income or other taxes. There can be no assurance that our effective tax rate or tax payments will not be adversely affected by these legislative measures. In addition, United States federal, state and local, as well as non-United States, tax laws and regulations are extremely complex and subject to varying interpretations. There can be no assurance that our tax positions will be sustained if challenged by relevant tax authorities and if not sustained, there could be a material impact on our results of operations.

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

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

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in certain claims, suits and legal proceedings in the normal course of business. The Company has accrued for litigation and claims where it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. The Company believes, based upon information it currently possesses and taking into account established reserves for estimated liabilities and its insurance coverage, that the ultimate outcome of these proceedings and actions is unlikely to have a material adverse effect on the Company's financial statements. It is reasonably possible, however, that some matters could be decided unfavorably to the Company and could require the Company to pay damages or make expenditures in amounts that could be material but cannot be estimated as of December 31, 2014.

In 1989, Centrais Elétricas Brasileiras S.A. ("Eletrobrás") filed suit in the Fifth District Court in the State of Rio de Janeiro ("FDC") against Eletropaulo Eletricidade de São Paulo S.A. ("EEDSP") relating to the methodology for calculating monetary adjustments under the parties' financing agreement. In April 1999, the FDC found for Eletrobrás and in September 2001, Eletrobrás initiated an execution suit in the FDC to collect approximately R$1.57 billion ($584 million) from Eletropaulo (as estimated by Eletropaulo) and a lesser amount from an unrelated company, Companhia de Transmissão de Energia Elétrica Paulista ("CTEEP") (Eletropaulo and CTEEP were spun off of EEDSP pursuant to its privatization in 1998). In November 2002, the FDC rejected Eletropaulo's defenses in the execution suit. On appeal, the case was remanded to the FDC for further proceedings to determine whether Eletropaulo is liable for the debt. In December 2012, the FDC issued a decision that Eletropaulo is liable for the debt. However, that decision was annulled on appeal and the case was remanded to the FDC for further proceedings. On remand at the FDC, the FDC has appointed an accounting expert who will issue a report on the amount of the alleged debt and the responsibility for its payment in light of the privatization. The parties will be entitled to take discovery and present arguments on the issues to be determined by the expert. If the FDC again finds Eletropaulo liable for the debt, after the amount of the alleged debt is determined, Eletrobrás will be entitled to resume the execution suit in the FDC. If Eletrobrás does so, Eletropaulo will be required to provide security for its alleged liability. In that case, if Eletrobrás requests the seizure of such security and the FDC grants such request, Eletropaulo's results of operations may be materially adversely affected and, in turn, the Company's results of operations could be materially adversely affected. In addition, in February 2008, CTEEP filed a lawsuit in the FDC against Eletrobrás and Eletropaulo seeking a declaration that CTEEP is not liable for any debt under the financing agreement. Eletropaulo believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In September 1996, a public civil action was asserted against Eletropaulo and Associação Desportiva Cultural Eletropaulo (the "Associação") relating to alleged environmental damage caused by construction of the Associação near Guarapiranga Reservoir. The initial decision that was upheld by the Appellate Court of the State of São Paulo in 2006 found that Eletropaulo should repair the alleged environmental damage by demolishing certain construction and reforesting the area, and either sponsor an environmental project which would cost approximately R$1.6 million ($596 thousand) as of December 31, 2014, or pay an indemnification amount of approximately R$15 million ($6 million). Eletropaulo has appealed this decision to the Supreme Court and the Supreme Court affirmed the decision of the Appellate Court. Following the Supreme Court's decision, the case has been remanded to the court of first instance for further proceedings and to monitor compliance by the defendants with the terms of the decision. In January 2014, Eletropaulo informed the court that it intended to comply with the court's decision by donating a green area inside a protection zone and restore watersheds, the aggregate cost of which is expected to be approximately R$1.6 million ($596 thousand). Eletropaulo also requested that the court add the current owner of the land where the Associação facilities are located, Empresa Metropolitana de Águas e Energia S.A. ("EMAE"), as a party to the lawsuit and order EMAE to perform the demolition and reforestation aspects of the court's decision. In July 2014, the court requested the Secretary of the Environment for the State of São Paulo to notify the court of its opinion regarding the acceptability of the green areas to be donated by Eletropaulo to the State of São Paulo.

In December 2001, Gridco Ltd. ("Gridco") served a notice to arbitrate pursuant to the Indian Arbitration and Conciliation Act of 1996 on the Company, AES Orissa Distribution Private Limited ("AES ODPL"), and Jyoti

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

In March 2003, the office of the Federal Public Prosecutor for the State of São Paulo, Brazil (“MPF”) notified Eletropaulo that it had commenced an inquiry into the BNDES financings provided to AES Elpa and AES Transgás, the rationing loan provided to Eletropaulo, changes in the control of Eletropaulo, sales of assets by Eletropaulo, and the quality of service provided by Eletropaulo to its customers. The MPF requested various documents from Eletropaulo relating to these matters. In July 2004, the MPF filed a public civil lawsuit in the Federal Court of São Paulo (“FCSP”) alleging that BNDES violated Law 8429/92 (the Administrative Misconduct Act) and BNDES’s internal rules by (1) approving the AES Elpa and AES Transgás loans; (2) extending the payment terms on the AES Elpa and AES Transgás loans; (3) authorizing the sale of Eletropaulo’s preferred shares at a stock-market auction; (4) accepting Eletropaulo’s preferred shares to secure the loan provided to Eletropaulo; and (5) allowing the restructurings of Light Serviços de Eletricidade S.A. and Eletropaulo. The MPF also named AES Elpa and AES Transgás as defendants in the lawsuit because they allegedly benefited from BNDES’s alleged violations. In May 2006, the FCSP ruled that the MPF could pursue its claims based on the first, second, and fourth alleged violations noted above. The MPF subsequently filed an interlocutory appeal with the Federal Court of Appeals (“FCA”) seeking to require the FCSP to consider all five alleged violations. The lawsuit remains before the FCSP, but the FCSP has suspended the lawsuit pending a decision on MPF's interlocutory appeal. AES Elpa and AES Brasiliana (the successor of AES Transgás) believe they have meritorious defenses to the allegations asserted against them and will defend themselves vigorously in these proceedings; however, there can be no assurances that they will be successful in their efforts.

Pursuant to their environmental audit, AES Sul and AES Florestal discovered 200 barrels of solid creosote waste and other contaminants at a pole factory that AES Florestal had been operating. The conclusion of the audit was that a prior operator of the pole factory, Companhia Estadual de Energia (“CEEE”), had been using those contaminants to treat the poles that were manufactured at the factory. On their initiative, AES Sul and AES Florestal communicated with Brazilian authorities and CEEE about the adoption of containment and remediation measures. In March 2008, the State Attorney of the State of Rio Grande do Sul, Brazil filed a public civil action against AES Sul, AES Florestal and CEEE seeking an order requiring the companies to recover the contaminated area located on the grounds of the pole factory and an indemnity payment (approximately R$6 million ($2 million)) to the State’s Environmental Fund. In October 2011, the State Attorney Office filed a request for an injunction ordering the defendant companies to contain and remove the contamination immediately. The court granted injunctive relief on October 18, 2011, but determined only that defendant CEEE was required to proceed with the removal work. In May 2012, CEEE began the removal work in compliance with the injunction. The removal costs are estimated to be approximately R$60 million ($22 million) and the work was completed in February 2014. In parallel with the removal activities, a court-appointed expert investigation took place, which was concluded in May 2014. The court-appointed expert final report was presented to the State Attorneys in October 2014, and in January 2015 to the defendant companies. The defendant companies have until March 2015 to present their response to the report. The case is in the evidentiary stage awaiting the conclusion of the court’s expert opinion on several matters, including which of the parties had utilized the products found in the area.The Company believes that it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In March 2009, AES Uruguaiana Empreendimentos S.A. (“AESU”) in Brazil initiated arbitration in the International Chamber of Commerce (“ICC”) against YPF S.A. (“YPF”) seeking damages and other relief relating to YPF’s breach of the parties’ gas supply agreement (“GSA”). Thereafter, in April 2009, YPF initiated arbitration in the ICC against AESU and two unrelated parties, Companhia de Gas do Estado do Rio Grande do Sul and Transportador de Gas del Mercosur S.A. (“TGM”), claiming that AESU wrongfully terminated the GSA and caused the termination of a transportation agreement (“TA”) between YPF and TGM (“YPF Arbitration”). YPF sought an unspecified amount of damages from AESU, a declaration that YPF’s performance was excused under the GSA due to certain alleged force majeure events, or, in the alternative, a declaration that the GSA and the TA should be terminated without a finding of liability against YPF because of the allegedly onerous obligations imposed on YPF by those agreements. In addition, in the YPF Arbitration, TGM asserted that if it was determined that AESU was responsible for the termination of the GSA, AESU was liable for TGM’s alleged losses, including losses under the TA. In April 2011, the arbitrations were consolidated into a single proceeding. The hearing on liability issues took place in December 2011. In May 2013, the arbitral Tribunal issued a liability award in AESU's favor. YPF thereafter challenged the award in Argentine court. That challenge remains pending. Also, there are competing decisions of the Argentine and Uruguayan courts on whether the arbitration should be suspended, including an Argentine appellate court's decision purporting to suspend the arbitration and a Uruguayan appellate court's decision directing the arbitration to continue. Given the competing decisions, the Tribunal suspended the damages phase of the arbitration until February 2, 2015, at which time the Tribunal was to consider whether to lift the suspension. Further, the Tribunal asked the parties to remove any alleged obstacles to the progress of the arbitration. However, to date, the Tribunal has not issued an order on whether to lift the suspension. AESU believes it has meritorious claims and defenses and will assert them vigorously; however, there can be no assurances that it will be successful in its efforts.

In April 2009, the Antimonopoly Agency in Kazakhstan initiated an investigation of certain power sales of Ust-Kamenogorsk HPP ("UK HPP") and Shulbinsk HPP, hydroelectric plants under AES concession (collectively, the "Hydros"). The Antimonopoly Agency determined that the Hydros had abused their market position and charged monopolistically high prices for power from January-February 2009. The Agency sought an order from the administrative court requiring UK HPP to pay an administrative fine of approximately KZT 120 million ($648 thousand) and to disgorge profits for the period at issue, estimated by the Antimonopoly Agency to be approximately KZT 440 million ($2 million). No fines or damages have been paid to date, however, as the proceedings in the administrative court have been suspended due to the initiation of related criminal proceedings against officials of the Hydros. In the course of criminal proceedings, the financial police expanded the periods at issue to the entirety of 2009 for UK HPP and from January-October 2009 for Shulbinsk HPP, and sought increased damages of KZT 1.2 billion ($6 million) from UK HPP and KZT 1.3 billion ($7 million) from Shulbinsk HPP. The Hydros believe they have meritorious defenses and will assert them vigorously in these proceedings; however, there can be no assurances that they will be successful in their efforts.

In October 2009, AES Mérida III, S. de R.L. de C.V. (AES Mérida), one of our businesses in Mexico, initiated arbitration against its fuel supplier and electricity offtaker, Comisión Federal de Electricidad (“CFE”), seeking a declaration that CFE breached the parties’ power purchase agreement (“PPA”) by supplying gas that did not comply with the PPA’s specifications. Alternatively, AES Mérida requested a declaration that the supply of such gas by CFE is a force majeure event under the PPA. CFE disputed the claims. Although it did not assert counterclaims, in its closing brief CFE asserted that it is entitled to a partial refund of the capacity charge payments that it made for power generated with the out-of-specification gas. In July 2012, the arbitral Tribunal issued an award in AES Mérida’s favor. In December 2012, CFE initiated an action in Mexican court seeking to nullify the award. AES Mérida opposed the request and asserted a counterclaim to confirm the award. In February 2014, the court rejected CFE's claims and granted AES Mérida's request to confirm the award. CFE has appealed the court's decision. AES Mérida believes it has meritorious grounds to defeat that action; however, there can be no assurances that it will be successful.

In October 2009, IPL received a Notice of Violation (“NOV”) and Finding of Violation from the EPA pursuant to the Clean Air Act (“CAA”) Section 113(a). The NOV alleges violations of the CAA at IPL’s three primarily coal-fired electric generating facilities dating back to 1986. The alleged violations primarily pertain to the Prevention of Significant Deterioration and nonattainment New Source Review requirements under the CAA. Since receiving the letter, IPL management has met with EPA staff regarding possible resolutions of the NOV. At this time, we cannot predict the ultimate resolution of this matter. However, settlements and litigated outcomes of similar cases have required companies to pay civil penalties, install additional pollution control technology on coal-fired electric generating units, retire existing generating units, and invest in additional environmental projects. A similar outcome in this case could have a material impact to IPL and could, in turn, have a material impact on the Company. IPL would seek recovery of any operating or capital expenditures related to air pollution control technology to reduce regulated air emissions; however, there can be no assurances that it would be successful in that regard.

In November 2009, April 2010, December 2010, April 2011, June 2011, August 2011, November 2011, and October 2014, substantially similar personal injury lawsuits were filed by a total of 50 residents and decedent estates in the Dominican Republic against the Company, AES Atlantis, Inc., AES Puerto Rico, LP, AES Puerto Rico, Inc., and AES Puerto Rico Services, Inc., in the Superior Court for the State of Delaware. In each lawsuit, the plaintiffs allege that the coal combustion by-products of AES Puerto Rico’s power plant were illegally placed in the Dominican Republic from October 2003 through March 2004 and subsequently caused the plaintiffs’ birth defects, other personal injuries, and/or deaths. The plaintiffs did not quantify their alleged damages, but generally alleged that they are entitled to compensatory and punitive damages. The Company is not able to estimate damages, if any, at this time. The AES defendants moved for partial dismissal of both the November 2009 and April 2010 lawsuits on various grounds. In July 2011, the Superior Court dismissed the plaintiffs’ international law and punitive damages claims, but held that the plaintiffs had stated intentional tort, negligence, and strict liability claims under Dominican law, which the Superior Court found governed the lawsuits. The Superior Court granted the plaintiffs leave to amend their complaints in accordance with its decision, and in September 2011, the plaintiffs in the November 2009 and April 2010 lawsuits did so. In November 2011, the AES defendants again moved for partial dismissal of those amended complaints, and in both lawsuits, the Superior Court dismissed the plaintiffs' claims for future medical monitoring expenses but declined to dismiss their claims under Dominican Republic Law 64-00. The AES defendants filed an answer to the November 2009 lawsuit in June 2012. The Superior Court has stayed the six lawsuits filed between April 2010 and November 2011, and may also stay the October 2014 lawsuit. Presently, discovery is proceeding only in the November 2009

lawsuit on causation and exposure issues. The AES defendants believe they have meritorious defenses and will defend themselves vigorously; however, there can be no assurances that they will be successful in their efforts.
On December 21, 2010, AES-3C Maritza East 1 EOOD, which owns a 670 MW lignite-fired power plant in Bulgaria, made the first in a series of demands on the performance bond securing the construction Contractor's obligations under the parties' EPC Contract. The Contractor failed to complete the plant on schedule. The total amount demanded by Maritza under the performance bond was approximately €155 million. The Contractor obtained an injunction from a lower French court purportedly preventing the issuing bank from honoring the bond demands. However, the Versailles Court of Appeal canceled the injunction in July 2011, and therefore the issuing bank paid the bond demands in full. In addition, in December 2010, the Contractor stopped commissioning of the power plant's two units, allegedly because of the purported characteristics of the lignite supplied to it for commissioning. In January 2011, the Contractor initiated arbitration on its lignite claim, seeking an extension of time to complete the power plant, an increase to the contract price, and other relief, including in relation to the bond demands. The Contractor later added claims relating to the alleged unavailability of the grid during commissioning and

Maritza's termination of the EPC Contract in March 2011. The Contractor sought approximately €240 million ($292 million) in the arbitration, plus interest and costs. Maritza rejected the Contractor's claims and asserted counterclaims for delay of liquidated damages and other relief relating to the Contractor's failure to complete the power plant and other breaches of the EPC Contract. The evidentiary hearing took place on November 27-December 6, 2013, and January 6-17, 2014. Closing arguments were heard on May 21-22, 2014. In December 2014, the parties settled the dispute.

On February 11, 2011, Eletropaulo received a notice of violation from São Paulo State's Environmental Authorities for allegedly destroying 0.32119 hectares of native vegetation at the Conservation Park of Serra do Mar ("Park"), without previous authorization or license. The notice of violation asserted a fine of approximately R$1 million ($372 thousand) and the suspension of Eletropaulo activities in the Park. As a response to this administrative procedure before the São Paulo State Environmental Authorities ("São Paulo EA"), Eletropaulo timely presented its defense on February 28, 2011 seeking to vacate the notice of violation or reduce the fine. In December 2011, the São Paulo EA declined to vacate the notice of violation but recognized the possibility of 40% reduction of the fine if Eletropaulo agrees to recover the affected area with additional vegetation. Eletropaulo has not appealed the decision and is now discussing the terms of a possible settlement with the São Paulo EA, including a plan to recover the affected area by primarily planting additional trees. In March 2012, the State of São Paulo Prosecutor's Office of São Bernardo do Campo initiated a Civil Proceeding to review the compliance by Eletropaulo with the terms of any possible settlement. Eletropaulo has had several meetings and field inspections to settle the details of the recovery project. Eletropaulo was informed by the Park Administrator that the area where the recovery project was to be located was no longer available. The Park Administrator subsequently approved a new area for the recovery project. Eletropaulo is currently awaiting the draft of the agreement by the environmental agency, and expects to proceed with the recovery project after reaching agreement with the environmental agency.

In June 2011, the São Paulo Municipal Tax Authority (the "Municipality") filed 60 tax assessments in São Paulo administrative court against Eletropaulo, seeking to collect services tax ("ISS") that allegedly had not been paid on revenues for services rendered by Eletropaulo. Eletropaulo challenged the assessments on the ground that the revenues at issue were not subject to ISS. In October 2013, the First Instance Administrative Court determined that Eletropaulo was liable for ISS, interest, and related penalties totaling approximately R$2.95 billion ($1 billion) as estimated by Eletropaulo. Eletropaulo has appealed to the Second Instance Administrative Court. No tax is due while the appeal is pending. Eletropaulo believes it has meritorious defenses to the assessments and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In January 2012, the Brazil Federal Tax Authority issued an assessment alleging that AES Tietê paid PIS and COFINS taxes from 2007 to 2010 at a lower rate than the tax authority believed was applicable. AES Tietê challenged the assessment on the ground that the tax rate was set in the applicable legislation. In April 2013, the First Instance Administrative Court determined that AES Tietê should have calculated the taxes at the higher rate and that AES Tietê was liable for unpaid taxes, interest and penalties totaling approximately R$864 million ($322 million) as estimated by AES Tietê. AES Tietê appealed to the Second Instance Administrative Court ("SAIC"). In January 2015, the SAIC issued a decision in AES Tietê's favor, finding that AES Tietê was not liable for unpaid taxes. The Tax Authority may appeal. AES Tietê believes it has meritorious defenses to the claim and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In August 2012, Fondo Patrimonial de las Empresas Reformadas ("FONPER") (the Dominican instrumentality that holds the Dominican Republic's shares in Empresa Generadora de Electricidad Itabo, S.A. ("Itabo")) filed a criminal complaint against certain current and former employees of AES. The criminal proceedings include a related civil component initiated against Coastal Itabo, Ltd. ("Coastal") (the AES affiliate shareholder of Itabo) and New Caribbean Investment, S.A. ("NC") (the AES affiliate that manages Itabo). FONPER asserts claims relating to the alleged mismanagement of Itabo and seeks approximately $270 million in damages. The Dominican District Attorney ("DA") has admitted the criminal complaint and is investigating the allegations set forth therein. In September 2012, one of the individual defendants responded to the criminal complaint, denying the charges and seeking an immediate dismissal of same. In April 2013, the DA requested that the Dominican Camara de Cuentas ("Camara") perform an audit of the allegations in the criminal complaint. The audit is ongoing and the Camara has not issued its report to date. Further, in August 2012, Coastal and NC initiated an international arbitration proceeding against FONPER and the Dominican Republic, seeking a declaration that Coastal and NC have acted both lawfully and in accordance with the relevant contracts with FONPER and the Dominican Republic in relation to the management of Itabo. Coastal and NC also seek a declaration that the criminal complaint is a breach of the relevant contracts between the parties, including the obligation to arbitrate disputes. Coastal and NC further seek damages from FONPER and the Dominican Republic resulting from their breach of contract. FONPER and the Dominican Republic have denied the claims and challenged the jurisdiction of the arbitral Tribunal. The Tribunal has established the procedural schedule for the arbitration, but has not yet scheduled dates for the final evidentiary hearing. The AES defendants believe they have meritorious claims and defenses, which they will assert vigorously; however, there can be no assurances that they will be successful in their efforts.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Recent Sales of Unregistered Securities

None.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Stock Repurchase Program

In July 2014, the Company's Board of Directors approved an increase of $140 million to the stock repurchase program (the "Program") under which the Company can repurchase AES common stock. The Board authorization permits the Company to repurchase stock through a variety of methods, including open market repurchases and/or privately negotiated transactions. There can be no assurances as to the amount, timing or prices of repurchases, which may vary based on market conditions and other factors. The Program does not have an expiration date and can be modified or terminated by the Board of Directors at any time. During the year ended December 31, 2014, the Company repurchased 21,900,246 shares of its common stock under the Program at a total cost of $308 million. At December 31, 2014, the cumulative repurchases under the Program totaled 105,912,477 shares at a total cost of $1.3 billion, at an average price per share of $12.37 (including a nominal amount of commissions).

The following table presents information regarding repurchases made by The AES Corporation of its common stock in the fourth quarter of 2014.

Repurchase Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Repurchased as Part of a Publicly Announced Purchase Plan	Dollar Value of Maximum Number of Shares to be Purchased Under the Plan
10/1/2014 - 10/31/14	2,960,908	14.19	2,960,908	$149,877,967
11/1/2014 - 11/30/14	3,106,165	13.66	3,106,165	107,463,716
12/1/2014 - 12/31/14	6,149,073	13.67	6,149,073	23,481,022
Total	12,216,146	$13.79	12,216,146	

Market Information

Our common stock is currently traded on the NYSE under the symbol "AES." The closing price of our common stock as reported by the NYSE on February 18, 2015, was $11.83 per share. The Company repurchased 21,900,246, 25,297,042, and 24,790,384 shares of its common stock in 2014, 2013 and 2012, respectively. The following tables set forth the high and low stock prices and cash dividends declared for the periods indicated:

	2014			2013		
	Sales Prices		Cash Dividends	Sales Prices		Cash Dividends
	High	Low	Declared	High	Low	Declared
First Quarter	$14.94	$13.42	$ —	$12.73	$10.66	$ —
Second Quarter	15.65	13.42	0.05	14.00	11.17	0.08
Third Quarter	15.64	14.01	0.05	13.77	11.62	—
Fourth Quarter	14.49	12.38	0.15	15.54	13.16	0.09

Dividends

The Company commenced a quarterly cash dividend of $0.04 per share beginning in the fourth quarter of 2012, which was increased to $0.05 per share beginning in the fourth quarter of 2013. During the fourth quarter of 2014, the Board of Directors voted to increase the quarterly dividend to $0.10 per share, beginning in the first quarter of 2015. There can be no assurance that the AES Board will declare the dividend or, if declared, the amount of any dividend. Our ability to pay dividends will also depend on receipt of dividends from our various subsidiaries across our portfolio. Under the terms of our senior secured credit facility, which we entered into with a commercial bank syndicate, we have limitations on our ability to pay cash dividends and/or repurchase stock. Our project subsidiaries' ability to declare and pay cash dividends to us is also subject to certain limitations contained in the project loans, governmental provisions and other agreements to which our project subsidiaries are subject. See the information contained under

Item 12.—Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters—Securities Authorized for Issuance under Equity Compensation Plans of this Form 10-K.

Holders

As of February 18, 2015, there were approximately 4,980 record holders of our common stock.

Performance Graph
THE AES CORPORATION
PEER GROUP INDEX/STOCK PRICE PERFORMANCE

Source: Bloomberg
We have selected the Standard and Poor's ("S&P") 500 Utilities Index as our peer group index. The S&P 500 Utilities Index is a published sector index comprising the 31 electric and gas utilities included in the S&P 500.
The five year total return chart assumes $100 invested on December 31, 2009 in AES Common Stock, the S&P 500 Index and the S&P 500 Utilities Index. The information included under the heading Performance Graph shall not be considered "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 or incorporated by reference in any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected financial data as of the dates and for the periods indicated. You should read this data together with Item 7.—Management's Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements and the notes thereto included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K. The selected financial data for each of the years in the five year period ended December 31, 2014 have been derived from our audited Consolidated Financial Statements. Prior period amounts have been restated to reflect discontinued operations in all periods presented. Effective July 1, 2014, the Company adopted new accounting guidance on discontinued operations. Please refer to Footnote 1 in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further explanation. Our historical results are not necessarily indicative of our future results.
Acquisitions, disposals, reclassifications and changes in accounting principles affect the comparability of information included in the tables below. Please refer to the Notes to the Consolidated Financial Statements included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further explanation of the effect of such activities. Please also refer to Item 1A.—Risk Factors of this Form 10-K and Note 26—Risks and Uncertainties to the Consolidated Financial Statements included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for certain risks and uncertainties that may cause the data reflected herein not to be indicative of our future financial condition or results of operations.

SELECTED FINANCIAL DATA

Statement of Operations Data	Years Ended December 31, 2014	2013	2012	2011[1]	2010
	(in millions, except per share amounts)				
Revenue	$17,146	$15,891	$17,164	$16,098	$14,644
Income (loss) from continuing operations[2]	1,176	730	(420)	1,602	1,420
Income (loss) from continuing operations attributable to The AES Corporation, net of tax	789	284	(960)	506	457
Discontinued operations, net of tax	(20)	(170)	48	(448)	(448)
Net income (loss) attributable to The AES Corporation	$769	$114	$(912)	$58	$9
Per Common Share Data					
Basic earnings (loss) per share:					
Income (loss) from continuing operations attributable to The AES Corporation, net of tax	$1.10	$0.38	$(1.27)	$0.65	$0.59
Discontinued operations, net of tax	(0.03)	(0.23)	0.06	(0.58)	(0.58)
Basic earnings (loss) per share	$1.07	$0.15	$(1.21)	$0.07	$0.01
Diluted earnings (loss) per share:					
Income (loss) from continuing operations attributable to The AES Corporation, net of tax	$1.09	$0.38	$(1.27)	$0.65	$0.59
Discontinued operations, net of tax	(0.03)	(0.23)	0.06	(0.58)	(0.58)
Diluted earnings (loss) per share	$1.06	$0.15	$(1.21)	$0.07	$0.01
Dividends Declared Per Common Share	$0.25	0.17	0.08	—	—

Balance Sheet Data:	December 31, 2014	2013	2012	2011[1]	2010
	(in millions)				
Total assets	$38,966	$40,411	$41,830	$45,346	$40,511
Non-recourse debt (noncurrent)	13,618	13,318	12,265	13,261	10,986
Non-recourse debt (noncurrent)—Discontinued operations	—	124	322	1,369	1,558
Recourse debt (noncurrent)	5,107	5,551	5,951	6,180	4,149
Cumulative preferred stock of subsidiaries	78	78	78	78	60
Retained earnings (accumulated deficit)	512	(150)	(264)	678	620
The AES Corporation stockholders' equity	4,272	4,330	4,569	5,946	6,473

(1) On November 28, 2011, AES completed the acquisition of 100% of the common stock of DPL Inc. Its results of operations have been included in AES's consolidated results of operations from the date of acquisition.

(2) Includes pretax impairment expense of $383 million, $596 million, $1.9 billion, $272 million, and $332 million for the years ended December 31, 2014, 2013, 2012, 2011 and 2010, respectively. See Note 9—Other Non-Operating Expense, Note 10—Goodwill and Other Intangible Assets and Note 21—Asset Impairment Expense included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information.

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

Key Topics in the Management Discussion and Analysis

Our discussion covers the following:

- Overview of 2014 Results and Strategic Performance
- Review of Consolidated Results of Operations
- SBU Analysis and Non-GAAP Measures
- Key Trends and Uncertainties
- Capital Resources and Liquidity

Overview of 2014 Results and Strategic Performance

Management's Strategic Priorities

Management is focused on the following priorities:

- Reducing complexity: By exiting businesses and markets where we do not have a competitive advantage, we have simplified our portfolio and reduced risk.
- Leveraging our platforms: Focusing our growth on platform expansions, including adjacencies, in markets where we already operate and have a competitive advantage to realize attractive risk-adjusted returns.
- Performance excellence: We strive to be the low-cost manager of a portfolio of assets and to derive synergies and scale from our businesses.
- Expanding access to capital: 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 other 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.

In 2014, we made significant progress on our strategy and continued to position our company for the future. We also met our financial guidance, despite sustained poor hydrological conditions in Latin America, particularly in Brazil and Panama, where rainfall has been at some of the lowest levels recorded in many decades. Our key achievements in 2014 were:

- Adjusted EPS of $1.30 and Proportional Free Cash Flow (FCF) of $891 million
- Diluted EPS from continuing operations of $1.09 and net cash provided by operating activities of $1.8 billion
- Returned 76% of discretionary cash to shareholders
- Increased our quarterly dividend by 100%, to $0.10 per share, beginning in the first quarter of 2015
- Invested $916 million in our balance sheet, by repurchasing shares and prepaying and refinancing debt
- Closed ten transactions for $1.8 billion in equity proceeds from asset sales
- Brought in four strategic partners to invest $1.9 billion in our subsidiaries
- Achieved goal of reducing global G&A expenses by $200 million one year early
- Capitalized on our existing footprint - broke ground on six new construction projects, totaling 2,226 MW, expected to come on-line from 2015 through 2018
- Awarded long-term PPAs by Southern California Edison, for 1,284 MW of combined cycle gas-fired generation and 100 MW of battery-based energy storage

2014 Strategic Performance

Earnings Per Share Results in 2014

	Years Ended December 31,		
	2014	2013	2012
Diluted earnings per share from continuing operations	$1.09	$0.38	(1.27)
Adjusted earnings per share (a non-GAAP measure)[1]	$1.30	$1.29	$1.21

[1] See reconciliation and definition under Non-GAAP Measures.

Diluted earnings per share from continuing operations increased $0.71, to $1.09, principally due to lower goodwill impairment expense and current year gains on the sale of investments. Additionally, higher interest income, foreign currency transaction gains, and lower general and administrative expenses added to the increase. These increases were partially offset by lower operating margin, higher income tax expense, and higher losses on debt extinguishments.

Adjusted EPS increased by 1% to $1.30 primarily due to lower Parent Company interest expense, lower general and administrative expenses, and lower share count, partially offset by lower contribution from the Asia SBU and increased tax expense.

Capital Management and Allocation

We continue to focus on improving cash generation and optimizing the use of our parent discretionary cash. During 2014, we generated $1.8 billion of cash flow from operating activities and closed multiple asset sales. In terms of uses, we deployed our discretionary cash to pay quarterly dividends of $0.05 per share, allocated $308 million to repurchase 22 million shares (see Note 16—Equity in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information), allocated $608 million to reduce recourse debt and extend near-term maturities at the Parent Company, and invested $327 million in our subsidiaries, largely for platform expansions. The largest investments in platform expansions in 2014 were related to environmental upgrades at IPL, where we expect to receive full recovery for qualifying costs, including a return on equity, and our expansion project at our Amman East facility in Jordan.

Reducing Complexity

In 2014, we announced or closed asset sale transactions representing $1.8 billion in equity proceeds to AES. With these transactions, we exited operations in Cameroon, Nigeria and Turkey. These asset sales are part of our strategy to maximize shareholder value by exiting markets where we do not have a compelling competitive advantage and reinvesting capital into expanding our platforms.

In 2014, we added 247 MW of new capacity, through one platform expansion project: IPP4 in Jordan. Our planned future capacity growth will come from a combination of projects currently under construction and development. We have 7,141 MW of new capacity under construction and expected to come on-line through 2018.

Safe, Reliable and Sustainable Operations

Our 2014 operating performance for the year was driven by the strategic management of our assets and cost reductions across our portfolio, but we also faced dry hydrological conditions across many markets in Latin America and reliability challenges at two of our generation assets in the Philippines and the US and utilities in Brazil.

We continue to focus on safety as our top priority. Our safety performance improved in 2014, as we lowered our lost-time incident case rates for both employees and operational contractors.

Generation in GWh is down 4% compared to 2013, mainly driven by dry hydrological conditions in Brazil and Panama, as well as higher unplanned outages at our generation plants in Ohio and Philippines. The dry conditions were partially offset by new capacity in Chile.

Compared to 2013, KPI performance declined in our generation metrics. Our Commercial Availability and EFOF performance deteriorated, largely driven by our unplanned outages at our generation plants in Ohio and the Philippines as discussed above. Most of these events have been resolved and mitigation plans have been implemented. Additionally, one strategic initiative focusing on coal blending can reduce the efficiency of certain generating units, which unfavorably affects our heat rate; however, it is offset by the financial benefits from utilizing lower-cost coal.

Our utility portfolio performance also declined mainly driven by severe weather-related impacts in our Brazil businesses which increased our SAIDI and SAIFI. However, we saw improvements in our non-technical losses performance mainly through strategic initiatives in our Brazil businesses on identifying and preventing fraudulent customers.

Our key performance indicators for the years ended December 31, 2014 and 2013 are as follows:

	2014		2013		Variance 2013-2014	
Safety: Employee Lost-Time Incident Case Rate	.082		.104		22%	
Safety: Operational Contractor Lost-Time Incident Case Rate	.078		.116		33%	
Generation						
Commercial Availability (%)	90.50	%	93.55	%	(3.05	)%
Equivalent Forced Outage Factor (EFOF, %)	3.29	%	2.92	%	(0.4	)%
Heat Rate (BTU/kWh)	9,791		9,638		(153	)
Utility						
System Average Interruption Duration Index (SAIDI, hours)	6.13		5.96		(0.17	)
System Average Interruption Frequency Index (SAIFI, number of interruptions)	3.70		2.97		(0.73	)
Non-Technical Losses (%)	2.03	%	2.52	%	0.49	%

Definitions:

- Lost-Time Incident Case Rate: Number of lost-time cases per number of full-time employees or contractors.
- Commercial Availability: Actual variable margin, as a percentage of potential variable margin if the unit had been available at full capacity during outages.
- Equivalent Forced Outage Factor: The percentage of the time that a plant is not capable of producing energy, due to unplanned operational reductions in production.
- Heat Rate: The amount of energy used by an electrical generator or power plant to generate one kilowatt-hour (kWh).
- System Average Interruption Duration Index: The total hours of interruption the average customer experiences annually.
- System Average Interruption Frequency Index: The average number of interruptions the average customer experiences annually.
- Non-Technical Losses: Delivered energy that was not billed due to measurement error, theft or other reasons.

Review of Consolidated Results of Operations

Results of operations	Years Ended December 31, 2014	2013	2012	% change 2014 vs. 2013	% change 2013 vs. 2012
	(in millions, except per share amounts)				
Revenue:					
US SBU	$3,826	$3,630	$3,736	5 %	-3 %
Andes SBU	2,642	2,639	3,020	— %	-13 %
Brazil SBU	6,009	5,015	5,788	20 %	-13 %
MCAC SBU	2,682	2,713	2,573	-1 %	5 %
Europe SBU	1,439	1,347	1,344	7 %	— %
Asia SBU	558	550	733	1 %	-25 %
Corporate and Other	15	7	9	114 %	-22 %
Intersegment eliminations	(25)	(10)	(39)	-150 %	74 %
Total Revenue	17,146	15,891	17,164	8 %	-7 %
Operating Margin:					
US SBU	699	668	711	5 %	-6 %
Andes SBU	587	533	580	10 %	-8 %
Brazil SBU	742	871	969	-15 %	-10 %
MCAC SBU	541	543	560	— %	-3 %
Europe SBU	403	415	504	-3 %	-18 %
Asia SBU	76	169	236	-55 %	-28 %
Corporate and Other	53	25	(15)	112 %	267 %
Intersegment eliminations	(13)	23	38	-157 %	-39 %
Total Operating Margin	3,088	3,247	3,583	-5 %	-9 %
General and administrative expenses	(187)	(220)	(274)	15 %	20 %
Interest expense	(1,471)	(1,482)	(1,544)	1 %	4 %
Interest income	365	275	348	33 %	-21 %
Loss on extinguishment of debt	(261)	(229)	(8)	-14 %	NM
Other expense	(68)	(76)	(82)	11 %	7 %
Other income	124	125	98	-1 %	28 %
Gain on disposal and sale of investments	358	26	219	NM	-88 %
Goodwill impairment expense	(164)	(372)	(1,817)	56 %	80 %
Asset impairment expense	(91)	(95)	(73)	4 %	-30 %
Foreign currency transaction gains (losses)	11	(22)	(170)	150 %	87 %
Other non-operating expense	(128)	(129)	(50)	1 %	-158 %
Income tax expense	(419)	(343)	(685)	-22 %	50 %
Net equity in earnings of affiliates	19	25	35	-24 %	-29 %
INCOME (LOSS) FROM CONTINUING OPERATIONS	1,176	730	(420)	61 %	274 %
Income (loss) from operations of discontinued businesses	27	(27)	47	200 %	-157 %
Net gain (loss) from disposal and impairments of discontinued operations	(56)	(152)	16	63 %	NM
NET INCOME (LOSS)	1,147	551	(357)	108 %	254 %
Noncontrolling interests:					
(Income) from continuing operations attributable to noncontrolling interests	(387)	(446)	(540)	13 %	17 %

(Income) loss from discontinued operations attributable to noncontrolling interests	9	9	(15)	— %	160 %
Net income (loss) attributable to The AES Corporation	$769	$114	$(912)	575 %	113 %
AMOUNTS ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:					
Income (loss) from continuing operations, net of tax	$789	$284	$(960)	178 %	130 %
Income (loss) from discontinued operations, net of tax	(20)	(170)	48	88 %	-454 %
Net income (loss)	$769	$114	$(912)	575 %	113 %
Net cash provided by operating activities	$1,791	$2,715	$2,901	-34 %	-6 %
DIVIDENDS DECLARED PER COMMON SHARE	$0.25	$0.17	$0.08	47 %	113 %

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NM — Not meaningful

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

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

Operating margin is defined as revenue less cost of sales.

Year ended December 31, 2014:

Revenue increased $1.3 billion, or 8%, to $17.1 billion in 2014 compared with $15.9 billion in 2013. The key operating drivers of the change at each of the SBUs are as follows:

- US — Overall favorable variance of $196 million driven by regulatory retail rate increases at DPL in Ohio as well as higher rates, primarily pass-through, at IPL in Indiana, partially offset by lower volume at DPL primarily due to customer switching.
- Andes — Overall favorable impact of $3 million driven by Chivor in Colombia due to higher spot and contract rates, somewhat offset by unfavorable foreign exchange rates, and Gener in Chile as a result of higher volume, partially offset by lower rates. Offsetting these results, Argentina decreased due to unfavorable foreign exchange rates.
- Brazil — Overall favorable impact of $994 million driven by higher volumes and higher tariffs, primarily pass-through costs, at Eletropaulo and Sul. Tietê also increased due to higher rates. Unfavorable foreign exchange partially offset these results.
- MCAC — Overall unfavorable impact of $31 million driven by the Dominican Republic due to lower third party gas sales, partially offset by higher PPA rates. El Salvador also decreased as a result of an unfavorable adjustment to unbilled revenue and lower pass-through costs. Offsetting these results, Puerto Rico and Panama increased due to higher volume and rates.
- Europe — Overall favorable impact of $92 million driven by the start of operations at Jordan IPP4 which commenced operations in July 2014 and Ballylumford in the U.K. due to higher volume and favorable foreign exchange rates, somewhat offset by lower rates. These results were partially offset by Kilroot in the U.K. primarily due to lower volume.
- Asia — Overall favorable impact of $8 million driven by higher pass-through fuel costs resulting from higher generation at Kelanitissa in Sri Lanka, partially offset by decrease in the Philippines primarily due to lower rates, somewhat offset by higher volume.

Operating margin decreased $159 million, or 5%, to $3.1 billion in 2014 compared with $3.2 billion in 2013. The key operating drivers of the change at each of the SBUs are as follows:

- US — Overall favorable impact of $31 million driven by favorable results at US Generation including contributions from a platform expansion project at Tait energy storage project, combined with higher availability at Hawaii and increased market prices at Laurel Mountain. US Utilities benefited with favorable results at IPL in Indiana driven by higher wholesale and retail margin as well as lower pension costs, were largely offset by lower results at DPL in Ohio. DPL was driven by outages and lower gas availability in the first half of 2014 resulting in higher purchased power and related costs to supply higher demand from cold weather, partially offset by improvements in Q3 2014 from increased retail rates, lower fuel costs and higher capacity prices. Revenue increases due to pass-through costs do not have a corresponding impact on operating margin.
- Andes — Overall favorable impact of $54 million driven by Chivor in Colombia due to higher generation, higher spot and contract prices, as well as ancillary services. Increases in Argentina were offset by lower results at Gener in Chile. Argentina increased due to the impact of Resolution 529, higher generation and availability, partially offset by higher fixed costs while Gener in Chile decreased due to lower contract and spot prices and lower availability, partially offset by full impact of new operations at Ventanas IV in 2014 and lower fixed costs.
- Brazil — Overall unfavorable impact of $129 million driven by unfavorable foreign exchange rates and Tietê due to lower water inflows which led to lower generation and an increase in energy purchases at higher prices, partially offset by higher spot sales in first half of 2014 due to lower contracted volumes of energy sold. In addition, Uruguaiana decreased due to a non-recurring extinguishment of a liability based on a favorable arbitration decision of $53 million in the second quarter of 2013. These results were partially offset by Eletropaulo driven by a non-recurring 2013 charge related to the recognition of a regulatory liability related to potential customer refunds as well as higher tariffs and volume. Revenue increases due to pass-through costs do not have a corresponding impact on operating margin.
- MCAC — Overall unfavorable impact of $2 million driven by El Salvador due to an unfavorable adjustment to unbilled revenue, higher energy losses and lower demand. These results were largely offset by the Dominican Republic mainly

related to higher spot sales and higher availability, partially offset by lower gas sales to third parties, lower frequency regulation, and lower PPA results.

- Europe — Overall unfavorable impact of $12 million driven by Kilroot in the U.K. and Maritza in Bulgaria due to lower volume and higher outages, partially offset by higher rates. These results were partially offset by the new operations at Jordan IPP4 as discussed above, and Kazakhstan due to higher generation volume and rates, partially offset by unfavorable foreign exchange rates.

- Asia — Overall unfavorable impact of $93 million driven by Masinloc in the Philippines, due to lower plant availability and the market operator's adjustment in the first quarter of 2014 to retrospectively recalculate energy prices related to an unprecedented increase in spot energy prices in November and December 2013, and lower spot rates, partially offset by higher contract demand. Kelanitissa also decreased due to a reduction in rates according to the PPA.

Year Ended December 31, 2013

Revenue decreased $1.3 billion, or 7%, to $15.9 billion in 2013 compared with $17.2 billion in 2012. The key operating drivers of the change at each of the SBUs are as follows:

- US — Overall unfavorable impact of $106 million driven by the early termination of the PPA at Beaver Valley in Pennsylvania in early 2013, customer switching as well as lower capacity rates at DPL in Ohio, and the short-term restart in 2012 of two Huntington Beach generating units at Southland in California, partially offset by higher wholesale volume and prices at IPL in Indiana.
- Andes — Overall unfavorable impact of $381 million driven by unfavorable foreign exchange rates of $128 million, lower prices from the impact of Resolution 95 in Argentina, and lower contract and spot prices at Gener in Chile, partially offset by higher spot prices at Chivor in Colombia as a result of dry hydrology.
- Brazil — Overall unfavorable impact of $773 million driven by unfavorable foreign exchange rates of $631 million, lower demand as well as lower pass-through costs and the tariff reset implemented in April 2013 at Sul, and a decrease at Eletropaulo related to the recognition of a regulatory liability for customer refunds (See Item 1.—Business—Brazil SBU— Eletropaulo Regulatory Asset Base Update) somewhat offset by higher tariffs. Negative results above partially offset by higher prices and sales at Tietê and the temporary restart of operations during February and March of 2013 at Uruguaiana.
- MCAC — Overall favorable impact of $140 million driven by higher spot prices as well as higher spot and gas sales to third parties in the Dominican Republic, higher prices in Mexico and Puerto Rico, partially offset by lower generation net of higher prices due to lower hydrology in Panama.
- Europe — Overall favorable impact of $3 million driven by higher energy prices at Kilroot in the UK, pass-through costs at Maritza in Bulgaria and Jordan, as well as higher dispatch and fewer outages at Ballylumford in the UK, partially offset by lower capacity prices. The favorable results above were largely offset by the sale of 80% of our ownership in Cartagena in Spain in February 2012 and a non-recurring favorable arbitration settlement in 2012 prior to final sale of remaining AES interest in April 2013.
- Asia — Overall unfavorable impact of $183 million due to higher contract levels at lower prices to reduce spot exposure, the reversal of a contingency and unrealized derivative gains in 2012 at Masinloc in the Philippines as well as lower generation at Kelanitissa in Sri Lanka as a result of higher hydrology.

Operating margin decreased $336 million, or 9%, to $3.2 billion in 2013 compared with $3.6 billion in 2012. The key operating drivers of the change at each of the SBUs are as follows:

- US — Overall unfavorable impact of $43 million driven by the short-term restart of two Huntington Beach units at Southland in 2012, higher outages and related fixed costs at Hawaii, and higher maintenance costs at IPL in Indiana. The negative drivers above were partially offset by higher contributions for US Wind businesses and DPL with lower amortization expense largely offset by higher customer switching.
- Andes — Largely unfavorable impact of $47 million driven by Chivor due to lower generation, somewhat offset by higher spot prices due to dry hydrology. Chile also decreased due to lower generation, higher spot purchases, and lower contract prices, offset by the commencement of operations of Ventanas IV in March 2013. These negative drivers were partially offset by an increase in Argentina driven by lower outages and higher volumes, somewhat offset by unfavorable foreign currency translation of $18 million and lower rates.
- Brazil — Overall unfavorable impact of $98 million driven by an unfavorable foreign exchange impact of $84 million, lower tariffs and demand at Sul, as well as lower volumes and higher energy purchases due to low hydrology at Tietê, partially offset by the favorable reversal of a liability and the temporary restart of operations at Uruguaiana and higher tariffs and lower fixed costs at Eletropaulo, somewhat offset by recognition of a regulatory liability as discussed above.
-

MCAC — Overall unfavorable impact of $17 million driven by Panama due to dry hydrological conditions, which resulted in lower generation and higher energy purchases at higher prices, somewhat offset by favorable net settlements. Negative drivers above were partially offset by the Dominican Republic with higher spot sales, higher international gas prices and volume of gas sales to third parties and higher availability in El Salvador due to the tariff increase at the beginning of 2013.

- Europe — Overall unfavorable impact of $89 million driven by Cartagena due to a non-recurring, favorable arbitration settlement in 2012 and the two-stage sale of the business as discussed above as well as Ballylumford due to lower capacity payments, somewhat offset by fewer outages. The negative results above were partially offset by favorable dark spreads from higher energy prices and lower coal costs at Kilroot and fewer outages and lower fixed costs at Maritza in Bulgaria.
- Asia — Overall unfavorable impact of $67 million driven by higher contracted volume at lower prices as discussed above as well as reversal of a contingency of $16 million and an unrealized derivative gain in 2012 at Masinloc.

General and administrative expenses

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

General and administrative expenses decreased $33 million, or 15%, to $187 million in 2014 from 2013 primarily due to lower employee-related costs and business development costs.

General and administrative expenses decreased $54 million, or 20%, to $220 million in 2013 from 2012 primarily due to Company restructuring efforts, resulting in a decrease in employee related costs, professional fees and business development costs.

Interest expense

Interest expense decreased $11 million, or 1%, to $1.5 billion in 2014 from 2013. The decrease was primarily attributable to lower interest expense of $53 million at the Parent Company due to a reduction in debt principal, and a $48 million reversal of contingent interest accruals associated with disputed purchased energy obligations at Sul for which it was determined, based on developments during the second quarter of 2014, that the likelihood of an unfavorable outcome for the payment of interest on the disputed obligation was no longer probable. These decreases were partially offset by income of $34 million in the prior year resulting from the ineffectiveness on derivative interest rate swaps accounted for as cash flow hedges at Puerto Rico, and higher interest expense of $24 million at Gener due to an increase in debt principal.

Interest expense decreased $62 million, or 4%, to $1.5 billion in 2013 from 2012. This decrease was primarily due to reduced debt principal as well as the prior year prepayment of an interest rate cash flow hedge that resulted in a reclassification of deferred losses from other comprehensive income to earnings at the Parent Company, favorable foreign currency translation and lower interest rates in Brazil, as well as income resulting from ineffectiveness on interest rate swaps in Puerto Rico that continue to qualify for hedge accounting. These decreases were partially offset by a monetary correction on the adjustment to the regulatory liability related to the asset base at Eletropaulo as a result of a ruling by the regulator in December 2013.

Interest income

Interest income increased $90 million, or 33%, to $365 million in 2014 from 2013. The increase was primarily due to interest income of $59 million recognized on FONINVEMEM III receivables in Argentina which satisfied the criteria for revenue recognition in the fourth quarter and $23 million in higher interest rates from an increase in regulatory assets at Eletropaulo. See Note 7—Financing Receivables included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information.

Interest income decreased $73 million, or 21%, to $275 million in 2013 from 2012. The decrease was primarily in Brazil, due to lower interest-bearing assets, lower investment balances, unfavorable foreign currency translation, and lower interest rates. The decrease was partially offset by interest income related to FONINVEMEM III receivables in Argentina which satisfied the criteria for revenue recognition during 2013.

Loss on extinguishment of debt

Loss on extinguishment of debt was $261 million for the year ended December 31, 2014. This loss was primarily related to $193 million, $31 million, and $20 million in early extinguishment of debt at the Parent Company, DPL, and Gener, respectively. See Note 12—Debt included in Item 8.—Financial Statements and Supplementary Data of this

Form 10-K for further information.

Loss on extinguishment of debt was $229 million and $8 million for the years ended December 31, 2013 and 2012. The loss in 2013 was primarily related to the loss on the early retirement of recourse debt at the Parent Company and the loss on the early extinguishment of debt at Masinloc. See Note 12—Debt included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information. The loss in 2012 was primarily related to a early retirement of debt at the Parent Company and at Eletropaulo.

Other income and expense

See discussion of the components of other income and expense in Note 20—Other Income and Expense included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information.

Gain on sale of investments

Gain on sale of investments for the year ended December 31, 2014 was $358 million, which is primarily related to the sale of 45% of our investment in Masin-AES Pte Ltd. and 100% of our interest in UK Wind. See Note 16—Equity of this form 10-K for further information.

Gain on sale of investments for the year ended December 31, 2013 was $26 million, which was primarily related to the sale of our remaining 20% interest in Cartagena as well as the sale of our 10% equity interest in Trinidad Generation Unlimited. See Note 24—Dispositions included in Item 8.—Financial Statements and Supplemental Data of this Form 10-K for further information.

Gain on sale of investments for the year ended December 31, 2012 was $219 million, which was primarily related to the sale of 80% of our interest in Cartagena, as well as the sale of certain investments in China.

Goodwill impairment

The Company recognized goodwill impairment expense of $164 million, $372 million, and $1.8 billion for the years ended December 31, 2014, 2013, and 2012. See Note 10—Goodwill and Other Intangible Assets included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information.

Asset impairment expense

The Company recognized asset impairment expense of $91 million, $95 million and $73 million, respectively, for the years ended December 31, 2014, 2013 and 2012. See Note 21—Asset Impairment Expense included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information.

Foreign currency transaction gains (losses)

Foreign currency transaction gains (losses) were as follows:

	Years Ended December 31,		
	2014	2013	2012
	(in millions)		
Argentina	$66	$2	$(5)
Colombia	17	6	(7)
United Kingdom	12	2	(6)
Philippines	11	(10)	(159)
Brazil	(4)	(12)	(16)
Mexico	(14)	—	3
Chile	(30)	(20)	9
AES Corporation	(34)	5	5
Other	(13)	5	6
Total[1]	$11	$(22)	$(170)

[1] Includes gains (losses) of $172 million, $60 million and $(160) million on foreign currency derivative contracts for the years ended December 31, 2014, 2013 and 2012, respectively.

The Company recognized net foreign currency transaction gains of $11 million for the year ended December 31, 2014 primarily due to gains of:

- $66 million in Argentina, due to the favorable impact from foreign currency derivatives related to government receivables, partially offset by losses from the devaluation of the Argentine Peso by 31% associated with U.S. Dollar denominated debt, and losses at Termoandes (a U.S. Dollar functional currency subsidiary) primarily associated with cash and accounts receivable balances in local currency, and the purchase of Argentine sovereign bonds;
- $17 million in Colombia, primarily due to a 23% depreciation of the Colombian Peso, positively impacting Chivor (a U.S. Dollar functional currency subsidiary) due to liabilities denominated in Colombian Pesos, primarily income tax payable and accounts payable;

- $12 million in the United Kingdom, primarily due to a 6% depreciation of the Pound Sterling, resulting in gains at Ballylumford Holdings (a U.S. Dollar functional currency subsidiary) associated with intercompany notes payable denominated in Pound Sterling, and gains related to foreign currency derivatives; and

- $11 million in the Philippines, primarily due to amortization of frozen embedded derivatives and a 4% appreciation of the Philippine Peso against the U.S. Dollar, resulting in a revaluation of cash accounts, customer receivables, and deferred tax asset.

These gains were partially offset by losses of:

- $34 million at The AES Corporation primarily due to decreases in the valuation of intercompany notes receivable denominated in foreign currency, resulting from the weakening of the Euro and British Pound during the year, partially offset by gains related to foreign currency option purchases;
- $30 million in Chile primarily due to a 16% devaluation of the Chilean Peso, resulting in a $39 million loss at Gener (a U.S. Dollar functional currency subsidiary) from working capital denominated in Chilean Pesos, primarily cash, accounts receivable and VAT receivables, partially offset by income of $9 million on foreign currency derivatives; and
- $14 million in Mexico, primarily due to a 13% devaluation of the Mexican Peso, resulting in a loss at TEGTEP and Merida (U.S. Dollar functional currency subsidiaries) from working capital denominated in Pesos (primarily cash, recoverable tax, and VAT).

The Company recognized foreign currency transaction losses of $22 million for the year ended December 31, 2013 primarily due to losses of:

- $20 million in Chile, primarily due to a 9% weakening of the Chilean Peso, resulting in losses at Gener (a U.S. Dollar functional currency subsidiary) associated with net working capital denominated in Chilean Pesos, mainly cash, accounts receivables and tax receivables, partially offset by gains related to foreign currency derivatives;
- $12 million in Brazil, primarily due to a 15% weakening of the Brazilian Real resulting in losses mainly associated with U.S. Dollar denominated liabilities; and
- $10 million in the Philippines (a U.S. Dollar functional currency subsidiary beginning in 2013), primarily due to the 8% weakening of the Philippine Peso, resulting in revaluation of cash accounts, customer receivables and deferred tax asset.

The Company recognized foreign currency transaction losses of $170 million for the year ended December 31, 2012 primarily due to losses of:

- $159 million in the Philippines, primarily due to unrealized foreign exchange losses on embedded derivatives as a result of the forecasted strengthening of the Philippine Peso, partially offset by gains from the 7% appreciation of the Philippine Peso on U.S. Dollar denominated debt at Masinloc, which had been a Philippine Peso functional currency subsidiary; and
- $16 million in Brazil, primarily due to a 9% devaluation of the Brazilian Real resulting in losses mainly associated with U.S. Dollar denominated liabilities.

Other non-operating expense

Total other non-operating expense was $128 million, $129 million and $50 million for the years ended December 31, 2014, 2013 and 2012. The amounts in 2014 consist of other-than-temporary impairment losses of $86 million and $42 million at Entek and Silver Ridge, respectively. See Note 9—Other Non-Operating Expense included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information.

Income tax expense

Income tax expense increased $76 million, or 22%, to $419 million in 2014. The Company’s effective tax rates were 27% and 33% for the years ended December 31, 2014 and 2013, respectively.

The net decrease in the 2014 effective tax rate was due, in part, to the 2014 sale of approximately 45% of the Company's interest in Masin AES Pte Ltd., which owns the Company's business interests in the Philippines, and the 2014 sale of the Company's interests in four U.K. wind projects. Neither of these transactions gave rise to income tax expense. Further, the 2014 effective tax rate benefited from the release of valuation allowance against U.S. capital loss carryforwards and a change in tax status at a subsidiary operating in the Dominican Republic. Offsetting these items is the unfavorable impact of Chilean income tax law reform enacted in the third quarter of 2014. See Note 16—Equity for additional information regarding the sale of approximately 45% of the Company's interest in Masin - AES Pte Ltd. See Note 24—Dispositions for additional information regarding the sale of the Company's interests in four U.K wind

projects. See Note 22—Income Taxes for additional information regarding the Chilean tax law reform.
Income tax expense decreased $342 million, or 50%, to $343 million in 2013. The Company’s effective tax rates were 33% and 298% for the years ended December 31, 2013 and 2012, respectively.

The net decrease in the 2013 effective tax rate was principally due to a 2012 nondeductible impairment of goodwill at our U.S. utility, DPL, and in part to the net favorable resolution of various uncertain tax positions in 2013. See Note 10—Goodwill and Other Intangible Assets for additional information regarding goodwill impairment.

Our effective tax rate reflects the tax effect of significant operations outside the United States, which are generally taxed at rates lower than the U.S. statutory rate of 35 percent. A future proportionate change in the composition of income before income taxes from foreign and domestic tax jurisdictions could impact our periodic effective tax rate.

We recognized tax expense of $419 million for the year ended December 31, 2014, while our cash payments for income taxes, net of refunds, totaled $480 million. The difference resulted primarily from income tax benefit on current year U.S. losses.

The Company also benefits from reduced tax rates in certain countries as a result of satisfying specific commitments regarding employment and capital investment. One such benefit related to our operations in the Philippines expired in the 4th quarter of 2014. Accordingly, the Company’s effective tax rate and cash tax payments may increase in future periods. See Note 22—Income Taxes for additional information regarding these reduced rates.

Net equity in earnings of affiliates

Net equity in earnings of affiliates decreased $6 million, or 24%, to $19 million in 2014 from $25 million in 2013. The decrease was primarily a result of an asset impairment charge at Elsta due to long lived assets that were determined to not be recoverable of which our share was $41 million. These items were partially offset by a $22 million lower loss recognized at Entek on an embedded foreign currency derivative and a $19 million increase as a result of the sale of equity interests in Silver Ridge Power, LLC ("SRP") See Note 8—Investments in and Advances to Affiliates included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information.

Net equity in earnings of affiliates decreased $10 million to $25 million in 2013 from $35 million in 2012. The decrease was primarily related to the sale of Yangcheng in China in the third quarter of 2012 as well as higher losses at Entek in Turkey resulting from a loss on an embedded foreign currency derivative, partially offset by increased earnings at Guacolda due to higher energy sales as a result of lower purchase costs.

Income from continuing operations attributable to noncontrolling interests

Income from continuing operations attributable to noncontrolling interests decreased $59 million, or 13%, to $387 million in 2014. The decrease was primarily due to decreased operating margin at Tietê related to lower hydrology and higher prices of energy purchased in the spot market, decreased operating margin at Uruguaiana due to a favorable arbitration settlement in 2013 for $53 million, and decreased operating margin at Panama related to lower hydrology. This was partially offset by increased operating margin at Eletropaulo due to the 2013 recognition of a $269 million regulatory liability related to customer refunds. For details on regulatory liabilities, see Note 11—Regulatory Assets and Liabilities.

Income from continuing operations attributable to noncontrolling interests decreased $94 million, or 17%, from $540 million to $446 million in 2013. This was primarily due to lower operating income at Tietê and Panama related to lower hydrology, the recognition of a regulatory liability related to customer refunds at Eletropaulo, and a reduction in income at Cartagena which was deconsolidated in February 2012 as a result of the sale of 80% of our interest.

Discontinued operations

Total discontinued operations was a net loss of $29 million, a net loss of $179 million, and a net income of $63 million for the years ended December 31, 2014, 2013 and 2012, respectively. See Note 23—Discontinued Operations and Held-for-Sale Businesses included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information.

Net income attributable to The AES Corporation

Net income attributable to The AES Corporation increased $655 million to $769 million in 2014 compared to net income of $114 million in 2013. The key drivers of the increase included:

- the gain on sale of 45% of our investment in Masin - AES Pte Ltd. as well as the gain on sale of the Company's entire interest in the UK Wind projects;
- lower goodwill impairment expense recognized in 2014 compared to 2013;
- higher interest income;

- lower general and administrative expense;
- gain on foreign currency transactions;
- increase in income from operations of discontinued businesses; and
- lower loss from disposal and impairments of discontinued businesses.

These increases were partially offset by:
- lower operating margin;
- increase in income tax expense; and
- higher losses from debt extinguishments.

Net income attributable to The AES Corporation was $114 million in 2013, which is an increase of $1.03 billion compared to net loss of $912 million in 2012. The key drivers included:
- lower goodwill impairment expense;
- lower income tax expense;
- lower foreign currency losses;
- lower interest expense, primarily at the Parent Company, due to a reduction in debt principal as well as the prior year prepayment of an interest rate cash flow hedge that resulted in a reclassification of deferred losses from other comprehensive income to earnings; and
- lower general and administrative expense.

These increases were partially offset by:
- lower operating margin as described above;
- the loss on the early extinguishment of debt at the Parent Company and at Masinloc;
- lower gain on sale of investments recorded in 2013 on the sale of our remaining 20% interest in Cartagena as well as our 10% equity interest in Trinidad compared to the prior year gain recorded from the sale of 80% of our interest in Cartagena in the first quarter of 2012;
- an increase in losses from the disposal and impairment of the discontinued businesses;
- other non-operating expense associated with an impairment at our equity method investment at Elsta in the Netherlands.

Non-GAAP Measures

Adjusted Operating Margin, Adjusted PTC, Adjusted EPS, and Proportional Free Cash Flow are non-GAAP supplemental measures that are used by management and external users of our consolidated financial statements such as investors, industry analysts and lenders.

Adjusted Operating Margin

Operating margin is defined as revenue less cost of sales. Cost of sales includes costs incurred directly by the businesses in the ordinary course of business, such as:
- Electricity and fuel purchases,
- Operations and maintenance costs,
- Depreciation and amortization expense,
- Bad debt expense and recoveries,
- General administrative and support costs at the businesses, and
- Gains or losses on derivatives associated with the purchase of electricity or fuel.

We define Adjusted Operating Margin as operating margin, adjusted for the impact of noncontrolling interests, excluding unrealized gains or losses related to derivative transactions.

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

Adjusted PTC and Adjusted EPS

We define Adjusted PTC as pretax income from continuing operations attributable to AES excluding gains or losses of
the consolidated entity due to (a) unrealized gains or losses related to derivative transactions, (b) unrealized foreign currency

gains or losses, (c) gains 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 also includes net equity in earnings of affiliates on an after-tax basis, adjusted for the aforementioned items.

Adjusted PTC reflects the impact of noncontrolling interests and excludes the items specified in the definition above. In addition to the revenue and cost of sales reflected in operating margin, Adjusted PTC includes the other components of our income statement, such as:

- General and administrative expense in the corporate segment, as well as business development costs;
- Interest expense and interest income;
- Other expense and other income;
- Realized foreign currency transaction gains and losses; and
- Net equity in earnings of affiliates.

We define Adjusted EPS as diluted earnings per share from continuing operations excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses related to derivative transactions, (b) unrealized foreign currency gains or losses, (c) gains 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.

The GAAP measure most comparable to Adjusted PTC is income from continuing operations attributable to AES. The GAAP measure most comparable to Adjusted EPS is diluted earnings per share from continuing operations. We believe that Adjusted PTC and Adjusted EPS better reflect the underlying business performance of the Company and are considered in the Company's internal evaluation of financial performance. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions, unrealized foreign currency gains or losses, losses due to impairments and strategic decisions to dispose of or acquire business interests or retire debt, which affect results in a given period or periods. In addition, for Adjusted PTC, earnings before tax represents the business performance of the Company before the application of statutory income tax rates and tax adjustments, including the effects of tax planning, corresponding to the various jurisdictions in which the Company operates. Adjusted PTC and Adjusted EPS should not be construed as alternatives to income from continuing operations attributable to AES and diluted earnings per share from continuing operations, which are determined in accordance with GAAP.

Proportional Free Cash Flow

Refer to Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Proportional Free Cash Flow (A non-GAAP Measure) for the discussion and reconciliation of Proportional Free Cash Flow to its nearest GAAP measure.

Reconciliations of Non-GAAP Measures

Adjusted Operating Margin

Reconciliation of Adjusted Operating Margin to Operating Margin	Years Ended December 31,		
	2014	2013	2012
Adjusted Operating Margin	(in millions)		
US	$711	$684	$707
Andes	444	402	431
Brazil	235	271	356
MCAC	482	472	489
Europe	373	392	447
Asia	51	159	204
Corp/Other	53	25	(15)
Intersegment Eliminations	(13)	23	38
Total Adjusted Operating Margin	2,336	2,428	2,657
Noncontrolling Interests Adjustment	760	833	908
Derivatives Adjustment	(8)	(14)	18
Operating Margin	$3,088	$3,247	$3,583

Adjusted PTC

Adjusted Pretax Contribution[1]	Total Adjusted PTC			Intersegment			External Adjusted PTC		
Year Ended December 31,	2014	2013	2012	2014	2013	2012	2014	2013	2012
	(in millions)								
US SBU	$445	$440	403	$10	$11	40	$455	$451	$443
Andes SBU	421	353	369	6	19	(16)	427	372	353
Brazil SBU	242	212	321	3	3	3	245	215	324
MCAC SBU	352	339	387	26	12	10	378	351	397
Europe SBU	348	345	375	5	7	(2)	353	352	373
Asia SBU	46	142	201	2	2	2	48	144	203
Corporate and Other	(533)	(624)	(717)	(52)	(54)	(37)	(585)	(678)	(754)
Total Adjusted Pretax Contribution	1,321	1,207	1,339	—	—	—	1,321	1,207	1,339
Reconciliation to Income from Continuing Operations before Taxes and Equity Earnings of Affiliates:									
Non-GAAP Adjustments:									
Unrealized derivative gains (losses)							135	57	(120)
Unrealized foreign currency gains (losses)							(110)	(41)	13
Disposition/acquisition gains							361	30	206
Impairment losses							(416)	(588)	(1,951)
Loss on extinguishment of debt							(274)	(225)	(16)
Pre-tax contribution							1,017	440	(529)
Add: Income from continuing operations before taxes, attributable to noncontrolling interests							578	633	794
Less: Net equity in earnings of affiliates							19	25	35
Income from continuing operations before taxes and equity in earnings of affiliates							$1,576	$1,048	$230

(1) Adjusted pretax contribution in each segment before intersegment eliminations includes the effect of intercompany transactions with other segments except for interest, charges for certain management fees and the write-off of intercompany balances.

Adjusted EPS

	Years Ended December 31,		
Reconciliation of Adjusted EPS	2014	2013	2012
Diluted earnings (loss) per share from continuing operations	$1.09	$0.38	$(1.26)
Unrealized derivative (gains) losses[1]	(0.12)	(0.05)	0.11
Unrealized foreign currency transaction (gains) losses[2]	0.14	0.02	(0.02)
Disposition/acquisition (gains)	(0.59) [3]	(0.03) [4]	(0.18) [5]
Impairment losses	0.53 [6]	0.75 [7]	2.55 [8]
Loss on extinguishment of debt	0.25 [9]	0.22 [10]	0.01 [11]
Adjusted EPS	$1.30	$1.29	$1.21

(1) Unrealized derivative (gains) losses were net of income tax per share of $(0.07), $(0.02) and $0.04 in 2014, 2013, and 2012, respectively.

(2) Unrealized foreign currency transaction (gains) losses were net of income tax per share of $0.02, $0.02 and $0.00 in 2014, 2013, and 2012, respectively.

(3) Amount primarily relates to the gain from the sale of a noncontrolling interest in Masinloc of $283 million ($283 million, or $0.39 per share, net of income tax per share of $0.00), the gain from the sale of the UK wind projects of $78 million ($78 million, or $0.11 per share, net of income tax per share of $0.00), the loss from the sale of Ebute of $6 million ($6 million, or $0.01 per share, net of income tax per share of $0.00), the loss from the liquidation of AgCert International of $1 million (net benefit of $18 million, or $0.03 per share, including income tax per share of

$0.03), the tax benefit of $24 million ($0.03 per share) related to the Silver Ridge Power transaction, the tax benefit of $18 million ($0.02 per share) associated with the agreement executed in December 2014 to sell a noncontrolling interest in IPALCO, and the tax benefit of $7 million ($0.01 per share) associated with the sale of a noncontrolling interest in our Dominican Republic businesses.

(4) Amount primarily relates to the gain from the sale of the remaining 20% of our interest in Cartagena for $20 million ($15 million, or $0.02 per share, net of income tax per share of $0.01) as well as the gain from the sale of Trinidad for $3 million ($4 million, or $0.01 per share, net of income tax per share of $0.00).

(5) Amount primarily relates to the gains from the sale of 80% of our interest in Cartagena for $178 million ($109 million, or $0.14 per share, net of income tax per share of $0.09) and equity method investments in China of $24 million ($25 million, or $0.03 per share, including an income tax credit of $1 million, or income tax per share of $0.00).

(6) Amount primarily relates to the goodwill impairments at DPLER of $136 million ($136 million, or $0.19 per share, net of income tax per share of $0.00), and at Buffalo Gap of $28 million ($28 million, or $0.04 per share, net of income tax per share of $0.00), and asset impairments at Ebute of $67 million ($64 million, or $0.09 per share, net of noncontrolling interest of $3 million and of income tax per share of $0.00), at DPL of $12 million ($7 million, or $0.01 per share, net of income tax per share of $0.01), at Newfield of $12 million ($6 million, or $0.01 per share, net of noncontrolling interest of $6 million and of income tax per share of $0.00), and at Elsta of $41 million ($31 million, or $0.04 per share, net of income tax per share of $0.01), as well as the other-than-temporary impairments of our equity method investment at Silver Ridge Power of $42 million ($27 million, or $0.04 per share, net of income tax per share of $0.02), and at Entek of $86 million ($86 million, or $0.12 per share, net of income tax per share of $0.00).

(7) Amount primarily relates to the goodwill impairments at DPL of $307 million ($307 million, or $0.41 per share, net of income tax per share of $0.00), at Ebute of $58 million ($58 million, or $0.08 per share, net of income tax per share of $0.00) and at Mountain View of $7 million ($7 million, or $0.01 per share, net of income tax per share of $0.00). Amount also includes an other-than-temporary impairment of our equity method investment at Elsta of $129 million ($128 million, or $0.17 per share, net of income tax per share of $0.00) and asset impairments at Beaver Valley of $46 million ($30 million, or $0.04 per share, net of income tax per share of $0.02), at DPL of $26 million ($17 million, or $0.02 per share, net of income tax per

share of $0.01), at Itabo (San Lorenzo) of $16 million ($6 million, or $0.01 per share, net of noncontrolling interest of $8 million and of income tax per share of $0.00), at El Salvador for $4 million ($4 million, or $0.01 per share, net of income tax per share of $0.00).

(8) Amount primarily relates to the goodwill impairment at DPL of $1.82 billion ($1.82 billion, or $2.39 per share, net of income tax per share of $0.00). Amount also includes other-than-temporary impairment of equity method investments in China of $32 million ($32 million, or $0.04 per share, net of income tax per share of $0.00), and at Inno Vent of $17 million ($17 million, or $0.02 per share, net of income tax per share of $0.00), as well as asset impairments of Wind turbines and projects of $41 million ($26 million, or $0.03 per share, net of income tax per share of $0.02) and asset impairments at Kelanitissa of $19 million ($17 million, or $0.02 per share, net of noncontrolling interest of $2 million and of income tax per share of $0.00) and at St. Patrick of $11 million ($11 million or $0.01 per share, net of income tax per share of $0.00).

(9) Amount primarily relates to the loss on early retirement of debt at the Parent Company of $200 million ($130 million, or $0.18 per share, net of income tax per share of $0.10), at DPL of $31 million ($20 million, or $0.03 per share, net of income tax per share of $0.02), at Electrica Angamos of $20 million ($11 million, or $0.02 per share, net of noncontrolling interest of $6 million and of income tax per share of $0.00), at UK wind projects of $18 million ($15 million, or $0.02 per share, net of income tax per share of $0.00), at Warrior Run of $8 million ($5 million, or $0.01 per share, net of income tax per share of $0.00) and at Gener of $7 million ($4 million, or $0.01 per share, net of noncontrolling interest of $2 million and of income tax per share of $0.00).

(10) Amount primarily relates to the loss on early retirement of debt at Parent Company of $165 million ($107 million, or $0.14 per share, net of income tax per share of $0.08), at Masinloc of $43 million ($39 million, or $0.05 per share, net of income tax per share of $0.00) and Changuinola of $14 million ($10 million, or $0.01 per share, net of income tax per share of $0.01).

(11) Amount primarily relates to the loss on retirement of debt at the Parent Company of $15 million ($10 million, or $0.01 per share, net of income tax per share of $0.01).

The Company reported a loss from continuing operations of $1.27 per share in 2012. For purposes of measuring diluted loss per share under GAAP, common stock equivalents were excluded from weighted-average shares as their inclusion would be anti-dilutive. However, for purposes of computing Adjusted EPS, the Company has included the impact of dilutive common stock equivalents as the inclusion of the defined adjustments result in income for Adjusted EPS. The table below reconciles the weighted-average shares used in GAAP diluted earnings per share to the weighted-average shares used in calculating the non-GAAP measure of Adjusted EPS.

	December 31, 2012		
	Loss	Shares	$ Per Share
Reconciliation of Denominator Used For Adjusted EPS	(in millions except per share data)		
GAAP DILUTED (LOSS) PER SHARE			
Loss from continuing operations attributable to The AES Corporation common stockholders	$(960)	755	$(1.27)
EFFECT OF DILUTIVE SECURITIES			
Stock options	—	1	—
Restricted stock units	—	4	0.01
NON-GAAP DILUTED (LOSS) PER SHARE	$(960)	760	$(1.26)

Operating Margin and Adjusted PTC Analysis

US SBU

The following table summarizes Operating Margin, Adjusted Operating Margin and Adjusted PTC for our US SBU for the periods indicated:

	For the Years Ended December 31,						
	2014	2013	2012	$ Change 2014 vs. 2013	$ Change 2013 vs. 2012	% Change 2014 vs. 2013	% Change 2013 vs. 2012

($’s in millions)							
Operating Margin	$699	$668	$711	$31	$(43)	5%	-6%
Noncontrolling Interests Adjustment	—	—	—				
Derivatives Adjustment	12	$16	(4)				
Adjusted Operating Margin	$711	$684	$707	$27	$(23)	4%	-3%
Adjusted PTC	$445	$440	$403	$5	$37	1%	9%

Fiscal year 2014 versus 2013

Operating margin for 2014 increased $31 million, or 5%. This performance was driven primarily by the following businesses and key operating drivers:

- US Generation increased by $26 million, primarily due to $11 million from increased availability as a result of fewer outages at Hawaii, $8 million at Laurel Mountain due to increased market prices, and $8 million due to the September 2013 completion of the Tait energy storage project; and
- IPL in Indiana increased $24 million driven by higher wholesale margin of $14 million and lower fixed costs of $11 million primarily due to lower pension expense.

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These increases were partially offset by:

- DPL decreased $19 million, primarily due to decreases of $71 million mainly attributable to outages which resulted in higher purchased power and related costs, especially in the first quarter when we experienced lower gas availability and higher demand as result of cold weather. Also contributing to the decrease was increased customer switching to third party CRES providers. These results were largely offset by higher rates of $57 million from increased retail rates, lower fuel costs and capacity pricing.

Adjusted Operating Margin increased $27 million for the US SBU due to the drivers above, excluding the impact of unrealized derivative gains and losses. AES owned 100% of its businesses in the US in 2014, so there is no adjustment for noncontrolling interests.

Adjusted PTC decreased $5 million driven by net gains of $53 million recognized as a result of the early termination of the PPA and coal supply contract at Beaver Valley during the first quarter of 2013, largely offset by an increase of $27 million in Adjusted Operating Margin described above as well as an increase in the Company's share of earnings under the HLBV allocation of noncontrolling interest at Buffalo Gap and Armenia Wind of $13 million and settlements at Laurel Mountain of $6 million.

Fiscal year 2013 versus 2012

Operating margin decreased by $43 million, or 6%. This performance was driven primarily by the following businesses and key operating drivers:

- US Generation decreased $26 million, driven by a $24 million decline from the short-term restart of two Huntington Beach units at Southland in 2012, and higher outages at Hawaii of $24 million, partially offset by higher contributions from the US Wind portfolio of $32 million; and
- IPL in Indiana declined $23 million, as a result of $13 million in higher maintenance costs driven by the timing and duration of major generating unit overhauls, and higher depreciation expense of $6 million due to additional utility plant assets placed in service.

These decreases were partially offset by:

- DPL increased $6 million, as lower amortization expense of $81 million offset:

A $30 million decrease in sales margin, as customer switching drove retail price decreases, partially offset by higher wholesale volumes;

Lower PJM capacity margins of $12 million; and

$19 million from unrealized gains on derivatives in 2012, which did not recur in 2013.

Adjusted Operating Margin decreased $23 million due to the drivers above, excluding the impact of unrealized derivative gains and losses. AES owns 100% of its businesses in the US, so there is no adjustment for noncontrolling interests.

Adjusted PTC increased $37 million driven by net gains of $53 million recognized as a result of the early termination of the PPA and coal supply contract at Beaver Valley, partially offset by the decrease of $23 million in Adjusted Operating Margin discussed above.

Andes SBU

The following table summarizes Operating Margin, Adjusted Operating Margin and Adjusted PTC for our Andes SBU for the periods indicated:

	For the Years Ended December 31,						
	2014	2013	2012	$ Change 2014 vs. 2013	$ Change 2013 vs. 2012	% Change 2014 vs. 2013	% Change 2013 vs. 2012
	($'s in millions)						
Operating Margin	$587	$533	$580	$54	$(47)	10 %	-8 %
Noncontrolling Interests Adjustment	$(143)	(131)	(149)				
Derivatives Adjustment	—	—	—				
Adjusted Operating Margin	$444	$402	$431	$42	$(29)	10 %	-7 %

Adjusted PTC	$421	$353	$369	$68	$(16	)	19 %	-4 %

Fiscal year 2014 versus 2013

Including the unfavorable impact of foreign currency translation and remeasurement of $14 million, operating margin increased $54 million, or 10%. This performance was driven primarily by the following businesses and key operating drivers:

- Chivor in Colombia increased $55 million of which $72 million was due to higher generation, higher spot and contract prices, and ancillary services, partially offset by higher maintenance costs of $12 million and unfavorable foreign exchange rates of $9 million.
- Argentina increased $8 million driven primarily by higher rates of $30 million as a result of the impact of Resolution 529, higher generation and availability of $13 million, partially offset by higher fixed costs of $27 million driven by higher inflation and unfavorable exchange rates of $5 million.

This increase was offset by:

- Gener in Chile decreased $9 million, largely driven by a reduction of $32 million from lower contract prices, spot prices in the SADI and lower Energy Plus margin and lower availability of $9 million; partially offset by the contribution of $10 million from Ventanas IV, which commenced operations in March 2013, and lower fixed costs from lower maintenance and salaries of $19 million.

Adjusted Operating Margin increased $42 million for the year due to the drivers above, adjusted for the impact of noncontrolling interests. AES owns 71% of Gener and Chivor and 100% of AES Argentina.

Adjusted PTC increased $68 million, driven by the increase of $42 million in Adjusted Operating Margin described above, and a net benefit of $45 million related to FONINVEMEM interest income on receivables in 2014 and 2013, partially offset by realized FX losses at Chile as well as non-recurring equity tax reversal of $8 million at Colombia in 2013.

Fiscal year 2013 versus 2012

Including the unfavorable impact of foreign currency translation and remeasurement of $18 million, operating margin for 2013 decreased $47 million, or 8%. This performance was driven primarily by the following businesses and key operating drivers:

- Chivor in Colombia decreased $42 million, as dry hydrological conditions reduced generation output and spot volumes but increased spot prices in the market. Lower volumes had an unfavorable impact of $115 million, partially offset by the favorable impact of $84 million from higher prices.
- Gener in Chile decreased $8 million, as a reduction of $30 million from lower contract prices and higher spot purchases was partially offset by higher generation of $24 million, as the commencement of operations at Ventanas IV in March 2013 was offset by lower gas availability and lower coal generation.

These decreases were partially offset by:

- AES Argentina increased $4 million, as lower outages of $18 million and higher volumes of $15 million were partially offset by lower rates of $8 million from the implementation of Resolution 95 and unfavorable exchange rates of $9 million.

Adjusted Operating Margin decreased $29 million due to the drivers above. AES owns 71% of Gener and Chivor and 100% of AES Argentina.

Adjusted PTC decreased $16 million driven by the decrease of $29 million in Adjusted Operating Margin described above, partially offset by higher interest income from the beginning of the accrual of interest on the FONINVEMEM III receivables in Argentina.

Brazil SBU

The following table summarizes Operating Margin, Adjusted Operating Margin and Adjusted PTC for our Brazil SBU for the periods indicated:

	For the Years Ended December 31,						
	2014	2013	2012	$ Change 2014 vs. 2013	$ Change 2013 vs. 2012	% Change 2014 vs. 2013	% Change 2013 vs. 2012
	($'s in millions)						
Operating Margin	$742	$871	$969	$(129)	$(98)	-15%	-10%
Noncontrolling Interests Adjustment	$(507)	(600)	(613)				
Derivatives Adjustment	—	—	—				

Adjusted Operating Margin	$235	$271	$356	$(36)	$(85)	-13%	-24%
Adjusted PTC	$242	$212	$321	$30	$(109)	14%	-34%

Fiscal year 2014 versus 2013

Including the unfavorable impact of foreign currency translation of $97 million, operating margin decreased $129 million, or 15%. This performance was driven primarily by the following businesses and key operating drivers:

- Tietê decreased $315 million, driven by unfavorable foreign exchange rates of $58 million and the net impact of $252 million of lower hydrology which led to lower generation and an increase in energy purchases at higher prices, partially offset by higher spot sales in the first half of 2014 due to lower contracted volumes of energy sold; and
- Uruguaiana decreased $51 million, as a result of the extinguishment of a liability based on a favorable arbitration decision of $53 million in the second quarter of 2013, partially offset by higher generation in 2014 during the period of temporary restart of operations.

These results were partially offset by:

- Eletropaulo increased $207 million, driven by a non-recurring 2013 charge related to the recognition of a regulatory liability of $198 million related to potential customer refunds, higher rates of $124 million driven by higher tariff and volume of $46 million, partially offset by higher fixed costs and depreciation of $133 million, primarily personnel/pension costs related, and unfavorable foreign exchange rates of $28 million; and
- Sul increased $31 million, due to higher volume and rates of $52 million, partially offset by higher fixed costs and depreciation of $11 million and unfavorable foreign exchange rates of $10 million.

Adjusted Operating Margin decreased $36 million primarily due to the drivers discussed above, adjusted for the impact of noncontrolling interests. AES owns 16% of Eletropaulo, 46% of Uruguaiana, 100% of Sul and 24% of Tietê.

Adjusted PTC increased $30 million, driven by the reversal of a loss contingency resulting from a change in estimate related to interest expense of $47 million that is no longer considered probable and 2014 municipalities settlement interest of $12 million at Sul, partially offset by the decrease of $36 million in Adjusted Operating Margin described above and higher interest rates and debt.

Fiscal year 2013 versus 2012

Including the unfavorable impact of foreign currency translation of $84 million, operating margin decreased $98 million, or 10%. This performance was driven primarily by the following businesses and key operating drivers:

- Sul decreased $96 million, due to lower tariffs of $33 million from the April 2013 tariff reset and lower volume of $44 million due to lower demand; and
- Tietê decreased $81 million, driven by the negative impact of foreign currency translation of $68 million as well as lower volume and higher energy purchases of $24 million due to lower hydrology.

These decreases were partially offset by:

- Uruguaiana increased $64 million, as a result of the extinguishment of a liability of $57 million and the temporary re-start of operations during February and March of 2013.
- Eletropaulo increased $17 million, driven by higher tariffs of $171 million and lower fixed costs of $42 million, partially offset by the recognition of a regulatory liability of $224 million related to potential customer refunds.

Adjusted Operating Margin decreased $85 million for the year primarily due to the drivers discussed above, adjusted for the impact of noncontrolling interests. AES owns 16% of Eletropaulo, 46% of Uruguaiana, 100% of Sul and 24% of Tietê.

Adjusted PTC decreased $109 million, as a result of the decrease of $85 million in Adjusted Operating Margin described above, and higher interest expense from higher outstanding debt and a monetary correction related to the asset base ruling for Eletropaulo in December 2013.

MCAC SBU

The following table summarizes Operating Margin, Adjusted Operating Margin and Adjusted PTC for our MCAC SBU for the periods indicated:

	For the Years Ended December 31,						
	2014	2013	2012	$ Change 2014 vs. 2013	$ Change 2013 vs. 2012	% Change 2014 vs. 2013	% Change 2013 vs. 2012
	($'s in millions)						
Operating Margin	$541	$543	$560	$(2)	$(17)	—%	(3)%
	$(59)	$(69)	$(74)				

Noncontrolling Interests Adjustment							
Derivatives Adjustment	—	(2)	3				
Adjusted Operating Margin	$482	$472	$489	$10	$(17)	2%	(3)%
Adjusted PTC	$352	$339	$387	$13	$(48)	4%	(12)%

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Fiscal year 2014 versus 2013

Including the unfavorable impact of currency translation of $3 million, operating margin decreased $2 million, or 0.4%. This performance was driven primarily by the following businesses and key operating drivers:

- El Salvador decreased $22 million, due primarily to a one-time unfavorable adjustment to unbilled revenue, as well as higher energy losses and other fixed costs; and
- Panama decreased $8 million, driven by dry hydrological conditions, which resulted in lower generation and higher energy purchases of $38 million and the Esti tunnel settlement agreement received during 2013 of $31 million, partially offset by compensation from the government of Panama of approximately $40 million related to spot purchases from dry hydrological conditions, as well as lower fixed and other costs of $22 million.

These decreases were partially offset by:

- Dominican Republic increased $19 million, mainly related to higher spot sales of $58 million and higher availability of $20 million, partially offset by lower gas sales to third parties of $27 million, lower frequency regulation of $26 million and lower PPA results of $14 million; and
- Puerto Rico increased by $6 million, driven by a favorable bad debt reversal.

Adjusted Operating Margin increased $10 million due to the drivers above, adjusted for the impact of noncontrolling interests and excluding unrealized gains and losses on derivatives. AES owns 89.8% of Changuinola and 49% of its other generation facilities in Panama, 100% of Andres and Los Mina and 50% of Itabo in the Dominican Republic, 99% of TEG/TEP and 55% of Merida in Mexico and a weighted average of 75% of its businesses in El Salvador.

Adjusted PTC increased $13 million, driven by the increase in Adjusted Operating Margin of $10 million as described above.

Fiscal year 2013 versus 2012

Including the unfavorable impact of foreign currency translation of $2 million, operating margin decreased $17 million, or 3%. This performance was driven primarily by the following businesses and key operating drivers:

- Panama decreased $75 million, driven by dry hydrological conditions, which resulted in lower generation and higher energy purchases at higher prices of $88 million, partially offset by favorable net settlements related to the Esti tunnel of $22 million.

This decrease was partially offset by:

- Dominican Republic increased $42 million, as a result of higher net energy transactions of $28 million, higher gas sales to third parties of $20 million, partially offset by $6 million due to other factors such as higher fixed costs.
- El Salvador increased $17 million, due to the tariff increase approved by the regulator at the beginning of 2013.

Adjusted Operating Margin increased $17 million due to the drivers above adjusted for the impact of noncontrolling interests and excluding unrealized gains and losses on derivatives. AES owns 89.8% of Changuinola (as of December 2013) and 49% of its other generation facilities in Panama, 100% of Andres and Los Mina and 50% of Itabo in the Dominican Republic, 99% of TEG/TEP and 55% of Merida in Mexico, and a weighted average of 75% of its businesses in El Salvador.

Adjusted PTC increased $48 million, driven by the increase in Adjusted Operating Margin of $17 million described above, and lower interest income in the Dominican Republic and the receipt of property damage insurance proceeds in 2012 related to the Esti tunnel in Panama.

Europe SBU

The following table summarizes Operating Margin, Adjusted Operating Margin and Adjusted PTC for our Europe SBU for the periods indicated:

	For the Years Ended December 31,						
	2014	2013	2012	$ Change 2014 vs. 2013	$ Change 2013 vs. 2012	% Change 2014 vs. 2013	% Change 2013 vs. 2012
	($'s in millions)						
Operating Margin	$403	$415	$504	$(12)	$(89)	-3%	-18%
	$(26)	$(23)	$(55)				

Noncontrolling Interests Adjustment							
Derivatives Adjustment	(4)	—	(2)				
Adjusted Operating Margin	$373	$392	$447	$(19)	$(55)	-5%	-12%
Adjusted PTC	$348	$345	$375	$3	$(30)	1%	-8%

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Fiscal year 2014 versus 2013

Including the unfavorable impact of foreign currency translation of $10 million, operating margin decreased $12 million, or 3%. This performance was driven primarily by the following businesses and key operating drivers:

- Kilroot decreased $31 million driven by lower dispatch and higher outages and related maintenance costs of $46 million, partially offset by higher rates of $13 million, including income from energy price hedges, and favorable foreign exchange rates; and
- Maritza decreased $17 million due to higher outages and related maintenance costs of $32 million, partially offset by higher rates of $10 million.

These results were partially offset by:

- Jordan increased $17 million as the IPP4 Jordan plant commenced operations in July 2014; and
- Kazakhstan increased $11 million driven by higher volumes and rates of $29 million, partially offset by unfavorable foreign exchange impact of $13 million.

Adjusted Operating Margin decreased $19 million due to the drivers above adjusted for noncontrolling interests, primarily Jordan with Amman East at 36% and IPP4 at 60%, and excluding unrealized gains and losses on derivatives.

Adjusted PTC increased $3 million, driven primarily by the decrease of $19 million in Adjusted Operating Margin described above, offset by the reversal of a liability of $18 million in Kazakhstan from the expiration of a statute of limitations for the Republic of Kazakhstan to claim payment from AES.

Fiscal year 2013 versus 2012

Including the favorable impact of foreign currency translation of $5 million, operating margin decreased $89 million, or 18%. This performance was driven primarily by the following businesses and key operating drivers:

- Cartagena in Spain decreased $105 million, as a result of:
  A non-recurring, favorable arbitration settlement of $95 million in the first quarter of 2012; and
  The two-stage sale of the business, as AES owned 71% of the facility through February 2012 and 14% through April 2013, when the sale was completed.
- Ballylumford in the U.K. decreased $29 million due to lower rates and capacity payments of $48 million, partially offset by fewer outages of $19 million.

These decreases were partially offset by:

- Maritza in Bulgaria increased $30 million driven by $10 million from fewer outages, $6 million of lower fixed costs, and favorable foreign exchange rates of $7 million.
- Kilroot in the U.K. increased $28 million driven by favorable dark spreads from higher energy prices and lower coal costs.

Adjusted Operating Margin decreased $55 million due to the drivers above adjusted for the impact of noncontrolling interests, primarily Cartagena in Spain due to the two stage sale of the business as described above, and excluding unrealized gains and losses on derivatives.

Adjusted PTC decreased $30 million, driven by the decrease of $55 million in Adjusted Operating Margin described above, partially offset by lower interest expense and realized foreign currency gains at Kilroot and higher equity earnings from Turkey and Elsta in the Netherlands.

Asia SBU

The following table summarizes Operating Margin, Adjusted Operating Margin and Adjusted PTC for our Generation businesses in Asia for the periods indicated:

	For the Years Ended December 31,						
	2014	2013	2012	$ Change 2014 vs. 2013	$ Change 2013 vs. 2012	% Change 2014 vs. 2013	% Change 2013 vs. 2012
	($'s in millions)						
Operating Margin	$76	$169	$236	$(93)	$(67)	-55%	-28%
Noncontrolling Interests Adjustment	(25)	(10)	(17)				

Derivatives Adjustment	—	—	(15)				
Adjusted Operating Margin	$51	$159	$204	$(108)	$(45)	-68%	-22%
Adjusted PTC	$46	$142	$201	$(96)	$(59)	-68%	-29%

Fiscal year 2014 versus 2013

Operating margin decreased $93 million, or 55%. This performance was driven primarily by the following businesses and key operating drivers:

- Masinloc in the Philippines decreased by $79 million, driven by $33 million due to lower plant availability, a net decrease of $21 million of lower spot rates partially offset by higher volume, an unfavorable impact of $15 million resulting from the market operator's adjustment in the first quarter of 2014 to retrospectively recalculate energy prices related to an unprecedented increase in spot energy prices in November and December 2013, higher maintenance costs of $4 million; and
- Kelanitissa in Sri Lanka decreased by $17 million, driven by the step-down in the contracted PPA price.

Adjusted Operating Margin decreased $108 million due to the drivers above adjusted for the impact of non-controlling interests and excluding unrealized gains on derivatives. AES owned 92% of Masinloc until July 2014 when AES reduced its ownership to 51%.

Adjusted PTC decreased $96 million, driven by the decrease of $108 million in Adjusted Operating Margin described above, partially offset by the impact of lower proportional interest expense at Masinloc and gains on foreign currency.

Fiscal year 2013 versus 2012

Operating margin decreased $67 million, or 28%. This performance was driven primarily by the following business and key operating drivers:

- Masinloc in Philippines decreased $62 million, due to:
  - The net impact of higher contracted volumes at lower prices, as a result of a new 7-year contract to reduce spot exposure, with an unfavorable impact of $31 million;
  - A reversal of a contingency of $16 million in 2012; and
  - An unrealized derivative gain of $15 million in 2012.

Adjusted Operating Margin decreased $45 million due to the drivers discussed above adjusted for the impact of noncontrolling interests and excluding unrealized gains on derivatives. AES owned 92% of Masinloc (prior to partial sale in 2014).

Adjusted PTC decreased $59 million, driven primarily by the decrease of $45 million in Adjusted Operating Margin described above, as well as a reduction in equity earnings from the sale of our businesses in China in 2012, partially offset by lower interest expense at Masinloc.

Key Trends and Uncertainties

During 2015 and beyond, we expect to face the following challenges at certain of our businesses. Management expects that improved operating performance at certain businesses, growth from new businesses and global cost reduction initiatives may lessen or offset their impact. If these favorable effects do not occur, or if the challenges described below and elsewhere in this section impact us more significantly than we currently anticipate, or if volatile foreign currencies and commodities move more unfavorably, then these adverse factors (or other adverse factors unknown to us) may impact our operating margin, net income attributable to The AES Corporation and cash flows. We continue to monitor our operations and address challenges as they arise. For the risk factors related to our business, see Item 1.—Business and Item 1A.—Risk Factors of this Form 10-K.

Regulatory

Philippines—In November and December 2013, the Philippines spot market witnessed an unprecedented price spike compared to historical levels. On March 11, 2014, the ERC declared the market prices from this period void and ordered the market operator to recalculate the prices for all market participants for November and December 2013 billing months. The recalculation of prices based on the load weighted average prices for the first nine months of 2013 resulted in an unfavorable adjustment of approximately $15 million to Masinloc spot sales. The ERC denied all motions for reconsideration filed by the generating companies.

Prior to the high price events in 2013, there was a primary price cap for spot prices set at 62,000 pesos per MWh. This cap was lowered to 32,000 pesos per MWh on January 4, 2014 pursuant to a joint resolution by the ERC, the Department of Energy (DoE) and the market operator. On May 5, 2014, a secondary price cap of 6,245 pesos per MWh was established on an interim basis to be applied when certain high price thresholds were met over time. On

December 15, 2014, the ERC issued a resolution to change the temporary nature of the secondary price cap into a permanent secondary price cap. Based on historical trends we do not expect either the primary or the secondary price cap mechanisms to be triggered.

Dominican Republic—In August 2014, the Superintendence of Electricity (Sectoral Regulatory Body of the Electricity Sector) modified the rules for offering primary frequency regulation service, an ancillary service item. The former rules allocated the service to generators based on merit order and those which were the most flexible and could enter the system quickly met the supply requirement. The new rule assigns a mandatory minimum margin to all generators which must be provided by its own source or through bilateral contracts with other generators who can offer the service. Additional supply requirements are allocated using the merit order process. The AES businesses, Andres and Los Mina, were previously lower in the merit order and received a majority of the allocation under the former rules. The lower allocation of this service to these units under the new rules will have an impact of lowering margin from frequency regulation, which will be partially offset by higher energy dispatch due to increased capacity.

Operational

Sensitivity to Dry Hydrological Conditions

Our hydroelectric generation facilities are sensitive to changes in the weather, particularly the level of water inflows into generation facilities. Throughout 2013 and 2014, dry hydrological conditions in Brazil, Panama, Chile and Colombia have presented challenges for our businesses in these markets. Low rainfall and water inflows caused reservoir levels to be below historical levels, reduced generation output, and increased prices for electricity. If hydrological conditions do not improve and our hydroelectric generation facilities cannot generate sufficient energy to meet contractual arrangements, we may need to purchase energy to fulfill our obligations, which could have a material adverse impact on our results of operations. Some local forecasts suggest continued dry conditions may continue through first half of 2015. Even if rainfall and water inflows return to historical average, high market prices and low generation could persist until reservoir levels are fully recovered.

In Brazil, the system operator controls all hydroelectric generation dispatch and reservoir levels, and there is a mechanism called MRE created to share hydrological risk across all generators. If the system of hydroelectric generation facilities generates less than the assured energy of the system, the shortfall is shared among generators, and depending on a generator's contract level, is fulfilled with spot market purchases. The system average inflows in 2014 were the 10th worst of the historical data since 1931. The consequences of unfavorable hydrology are (i) thermal plants (more expensive to the system) being dispatched, (ii) lower hydro power generation with deficits in the MRE and (iii) high spot prices. During 2014 spot prices sustained significantly high levels causing financial stress to most agents in the energy sector. From February to April 2014, the spot price was at the cap level of R$822/MWh, contributing to the average spot price of R$690/MWh in 2014. During October and November 2014, ANEEL conducted a public hearing to define a new spot price cap, reducing it from R$822/MWh to R$388/MWh from January 2015 forward. The lower cap price will result in a meaningful reduction on expenses for the agents that are negatively exposed to the spot price in 2015.

We expect the system operator in Brazil to continue to pursue a more conservative reservoir management strategy going forward, including the dispatch of up to 17 GW of thermal generation capacity, which could result in lower dispatch of hydroelectric generation facilities and electricity prices at high levels. AES Tietê has contract obligations throughout 2015 and may need to fulfill some of these obligations with spot purchases, so they will be sensitive to generation output and spot prices for electricity during this period. In addition, the costs incurred by our distribution companies, AES Eletropaulo and AES Sul, on energy purchases are passed through to customers with adjustments on a yearly basis, so working capital will be sensitive to significant increases in energy prices. In order to reduce potential working capital needs, on February 2015 ANEEL opened two public hearings i) to discuss an Extraordinary Tariff Review 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 are expected to increase tariffs starting in March 2015, anticipating pass-through of energy costs thus reducing potential working capital needs for distribution companies.

Finally, if dry conditions persist into the next rainy season through April 2015, there is a risk that the government of Brazil could implement a rationing program in 2015. If rationing were to occur, we would expect rules to be implemented that may include, but are not limited to, i) adjustments to hydroelectric generation PPAs in accordance with the overall load reduction affecting contracting position of hydroelectric generators and distribution companies,

ii) reduction in energy consumption impacting hydroelectric generation and margins of distribution companies, iii) increases in costs for distribution companies to provide additional customer services, communications, and to comply with rationing decree rules and iv) increases in losses and delinquency for distribution companies due to higher tariffs and potential penalties. As a result, if below long-term average hydrology continues and/or Brazil implements a rationing program, we would expect there to be an adverse impact on our results of operations and cash flows of our generation and distribution businesses in Brazil. Finally, an Extraordinary Tariff Review may be applied to partially or completely offset the reduction in margin and increase on costs, losses and delinquency incurred by distribution companies due to rationing, mitigating the adverse impact on results.

In Panama, dry hydrological conditions continued in 2014 reducing generation output from hydroelectric facilities and increasing spot prices for electricity. From March to June 2014, the government of Panama implemented certain energy saving measures designed to reduce demand for electricity during the peak hours by approximately 300 MW, which contributed to water savings in the key hydroelectric dams and lower spot prices. AES Panama had to purchase energy on the spot market to fulfill its contract obligations when its generation output is below its contract levels, and we expect this trend to continue through the first half of the year which will continue to impact our results of operations. As authorized on March 31, 2014, the government of Panama agreed to reduce the financial impact of spot electricity purchases and transmission constraints equivalent to a 70MW 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. Compensation payments recognized through December 31, 2014 were $40 million, of which $3 million are pending to be collected. Additionally, as part of our strategy to reduce our reliance on hydrology, AES Panama acquired a 72MW power barge for $27 million, financed with non-recourse debt, in September 2014, which we expect to become operational in the first quarter of 2015.

Taxes

The Company expects its effective tax rate in future years to be higher than the current year effective rate of 27%. As discussed in Item 7.— Review of Consolidated Results of Operations, the current year rate was favorably impacted by certain non-recurring items and the Company's benefit from reduced income tax rates on its operations in the Philippines which expired in the fourth quarter of 2014. Further, as noted in Critical Accounting Policies and Estimates (also in Item 7. of this Form 10-K), the Company is subject to higher income tax rates in Colombia for the next four years.

Macroeconomic and Political

During the past few years, economic conditions in some countries where our subsidiaries conduct business have deteriorated. Global economic conditions remain volatile and could have an adverse impact on our businesses in the event these recent trends continue.

Argentina—In Argentina, economic conditions remain unfavorable, as measured by indicators such as non-receding inflation, increased government deficits, diminished sovereign reserves, lack of foreign currency accessibility, the potential for continued devaluation of the local currency, and a decline in expectations for economic growth. Many of these economic conditions in conjunction with the restrictions to freely access the foreign exchange currency established by the Argentine Government since 2012, have contributed to the development of a limited parallel unofficial foreign exchange market that is less favorable than the official exchange. At December 31, 2014, 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. In January 2014, the Argentine Peso devalued by approximately 20%, the most rapid depreciation since 2002. While the currency has stabilized in the later part of 2014, 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. Argentina defaulted on its public debt in 2001, when it stopped making payments on about $100 billion amid a deep economic crisis. In 2005 and 2010, Argentina restructured its defaulted bonds into new securities valued at about 33 cents on the dollar. Between the two transactions, 93% of the bondholders agreed to exchange their defaulted bonds for new bonds. The remaining 7% did not accept the restructured deal. Since then, a certain group of the "hold-out" bondholders have been in judicial proceedings with Argentina regarding payment. More recently, the United States District Court ruled that Argentina would need to make payment to such hold-out bondholders according to the original applicable terms. Despite intense negotiations with the hold-out bondholders through the U.S. District Court appointed Special Master, on July 30, 2014 the parties failed to reach a settlement agreement and consequently (as referred by S&P and Fitch ratings) Argentina fell into a selective default resulting from failure to make interest payments on its Discount Bonds maturing in December 2033. Although this situation remains unresolved, it has not caused any significant changes that impact our current exposures, however, as noted above, there could be impacts on our businesses in the future.

Bulgaria—Our investments in Bulgaria rely on offtaker contracts with NEK, the state-owned electricity public supplier and energy trading company. Maritza, a lignite-fired generation facility, has experienced ongoing delays in the collection of outstanding receivables as a result of liquidity issues faced by NEK. In November 2013, Maritza and

NEK signed a rescheduling agreement for the overdue receivables as of November 12, 2013. Under the terms of the agreement, NEK paid $70 million of the overdue receivables and agreed to pay the remaining receivables in 13 equal monthly installments beginning December 2013. NEK has made payments according to the schedule through December 2014 when the final installment was paid. On July 31, 2014 Maritza entered into a tripartite agreement with NEK and Mini Maritza Iztok EAD ("MMI"), our fuel supplier, which reduced Maritza's outstanding receivables from NEK by $17 million through an offset of payables due by Maritza to MMI. Additionally in 2014, NEK paid four additional monthly installments totaling $28 million as agreed upon on time. As of December 31, 2014, Maritza had outstanding receivables of $262 million, representing $57 million of current receivables, $75 million of receivables overdue by less than 90 days and $130 million of receivables overdue by more than 90 days. Although Maritza continued to collect overdue receivables during the fourth quarter of 2014 and thereafter, there continue to be risks associated with collections, which could result in a write-off of the remaining receivables and/or liquidity problems which could impact Maritza's ability to meet its obligations, if the situation around collections were to deteriorate significantly. No allowance has been recognized on the receivables as the Company continues to assert that collection is probable. See Note 12—Debt included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information on current existing debt defaults. Litigation related to construction delays and related matters was settled in December 2014. For further information on the litigation see Item 3.—Legal Proceedings.

In May and June 2014, Bulgaria's 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 further 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, including taking one of Maritza's units out of the PPA and reducing the price of the remaining unit's output by 30%. However, SEWRC confirmed that until such negotiations conclude, the PPA is in full force and effect and NEK has not objected to Maritza's invoices. Maritza has filed appeals and requests for suspension of these SEWRC decisions with the Supreme Administrative Court in Bulgaria. The requests for suspension were denied by SAC. Further, on November 17, 2014, SEWRC replaced its May 2014 decision taking one of Maritza's units out of the PPA and reducing the price of the remaining unit's output by 30% with a decision which only required NEK and Maritza to start negotiations towards amending the PPA, without any prescribed parameters. Following the repeal of the decision, Maritza withdrew its appeal against that decision but continues to appeal the other May 2014 decisions. In addition, SEWRC announced in June 2014 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. If necessary, Maritza will defend the PPA in any assessment or proceeding that may be initiated by DG Comp in response to SEWRC's request.

In June 2014, new measures aiming at allocating to renewable energy producers the cost associated with the imbalance between forecasted and actual generation (known as Balancing Market) became effective. Saint-Nikola, a wind farm located in Kavarna, has been negatively impacted by these measures. Saint-Nikola is challenging the validity of the calculation methodology with SEWRC, and will take all actions necessary to protect its interests.

On July 24, 2014, the Government of Bulgaria formally resigned and the Caretaker Government was appointed by the President. Preliminary Parliamentary Elections were held on October 5, 2014. A coalition led by center-right party GERB formed a new government led by Prime Minister Boyko Borisov. The new government set as one of its priorities the restructuring of the energy sector, which is necessary to restore NEK's liquidity. The first measure announced by the new government was an end-consumer energy price increase of approximately 10% effective October 1, 2014. The other measures are being prepared by the Energy Commission of the Parliament, and are expected to be promulgated by June 2015. One of the components of the energy sector restructuring is the negotiation of an amendment of Maritza's PPA. Maritza has engaged in negotiations with SEWRC, NEK, and other Bulgarian instrumentalities concerning these matters. In February 2015, the Company signed a Memorandum of Understanding with the Government of Bulgaria to commence negotiations on proposed amendments to the existing PPA with NEK, which includes the payment of all outstanding receivables. Maritza will take all actions necessary to protect its interests, whether through negotiated agreement with NEK or through enforcement of its rights under the PPA.

Furthermore, as noted in Item 1.—Business—Bulgaria, during the fourth quarter of 2013, NEK requested a consent from Maritza for a restructuring. In February 2014, the NEK restructuring was implemented after approval by the regulatory authorities. As a result, NEK's credit rating fell below the rating NEK had upon the issuance of the Government Support Letter in 2005. Also, as a result of this restructuring NEK transmission license was revoked by the Regulator. These are defaults under the PPA, which triggered additional events of default under the project debt agreements. For further information on the importance of long-term contracts and our counterparty credit risk, 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.

As of December 31, 2014, we concluded there is no indicator of an impairment of the long-lived assets in Bulgaria for Maritza, which were $1.3 billion and total debt of $690 million, and Kavarna, which were $242 million and total debt of $168 million. Therefore, management believes the carrying amount of the asset group is recoverable as of December 31, 2014.

In December 2014 the Agency for State Financial Inspection started an audit to evaluate the compliance of Maritza with Public Procurement rules. Based on an extensive regulatory review conducted in 2011 at the time of Maritza plant commissioning, Maritza does not follow Public Procurement rules and will defend its rights if necessary after the conclusion of the audit, expected by June 2015.

Puerto Rico— Our subsidiary in Puerto Rico has a long-term PPA with the PREPA, a state-owned entity that supplies virtually all of the electric power consumed in the Commonwealth and generates, transmits and distributes electricity to 1.5 million customers. As a result of macroeconomic challenges in the country, including a seven-year recession, PREPA faces economic challenges including, but not limited to, reliance on high cost fuel oil, decline in electricity sales, high customer power rates, high operating costs, past due accounts receivable from government institutions, and very low liquidity along with challenges obtaining financing due to the recent downgrades, and has struggled to honor its payment obligations to electricity generators on a timely basis.

In February 2014, all agencies downgraded the Commonwealth of Puerto Rico and its public sector companies (PREPA included) to below investment grade. On June 28, 2014, the Governor of Puerto Rico signed into law the Recovery Act, which allows public corporations to adjust their debts in the interest of all creditors and establishes procedures for the orderly enforcement. With the recent passing of the Recovery Act, the ratings were further reduced. The downgrade on PREPA has had a direct impact on AES Puerto Rico's bonds. While Fitch rates both AES PR and PREPA with CC, Moody's rates AES Puerto Rico bonds (B3) three notches above PREPA (Caa3) citing as reasons the priority position of PREPA's contractual payments to AES PR as an operating expense as well as the project's strategic importance to PREPA as an efficient, reliable and relatively low cost source of power. We believe that AES Puerto Rico’s unique position as the lowest cost energy producer and cost-effective alternative for PREPA relative to fuel oil generated power, positions the business well and reduces the probability of negative impacts from a potential PREPA restructuring process. However, there can be no assurance as to the final terms of any restructuring or potential impacts on AES Puerto Rico.

On December 14, 2014 PREPA presented the first stage of the business plan to bondholders, which laid out key financial information on the current affairs of PREPA. The report, presented by PREPA's Chief Restructuring Officer ("CRO") complied with a key milestone in the Forbearance Agreement that expires on March 2, 2015 with bondholders. While the report is subject to strict confidentiality clauses, the CRO has stated that it does not contain recommendations or proposals on the utility’s capital structure, rates, payroll or any other fronts. During January, the CRO informed that their recommendations will not be ready until June 2015. The CRO is required to submit the recommendations to the Forbearance Committee which should state whether PREPA intends to restructure its debt combined with other restructuring actions on vendor negotiations, fuel cost contacts, capital needs and labor costs.

If AES Puerto Rico fails to receive payment in accordance with the terms of the PPA with PREPA, its liquidity issues could worsen, which could impact AES Puerto Rico's ability to meet its obligations. For further information, see Item 1A.—Risk Factors—“We may not be able to enter into long-term contracts, which reduce volatility in our results of operations” and "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 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. AES Puerto Rico's receivables balance as of December 31, 2014 is $89 million, of which $24 million is overdue. Subsequent to December 31, 2014, the full overdue amount has been collected.

Our Puerto Rico business will take all actions necessary to protect its interests, whether through negotiated agreement with PREPA or through enforcement of its rights under the PPA. In October 2014, the Parent Company reached an agreement with an investor in AES Puerto Rico's preferred shares to retire the investment at a fixed redemption value of $52 million. As the events pertaining to the Recovery Act continue to unfold, we concluded that there was no indicator of an impairment of the long-lived assets in Puerto Rico, which were $632 million and total debt of $528 million. Therefore, management believes the carrying amount of the asset group is recoverable as of December 31, 2014.

If the above referenced economic conditions deteriorate further, it could also affect the prices we receive for the electricity we generate or transmit. Utility regulators or parties to our generation contracts may seek to lower our prices based on prevailing market conditions pursuant to PPAs, concession agreements or other contracts as they come up for renewal or reset. In addition, rising fuel and other costs coupled with contractual price or tariff decreases could restrict our ability to operate profitably in a given market. Each of these factors, as well as those discussed above, could result in a decline in the value of our assets including those at the businesses we operate, our equity investments and projects under development and could result in asset impairments that could be material to our operations. We continue to monitor our projects and businesses.

Impairments

Goodwill — In the fourth quarter of 2014, the Company completed its annual October 1 goodwill impairment tests and recognized goodwill impairment expense of $10 million. Year to date, the Company has recognized goodwill impairment expense of $164 million. The Company has no reporting units considered to be "at risk." A reporting unit is considered “at risk” when its fair value is not higher than its carrying amount by more than 10%. The Company monitors its reporting units at risk of step 1 failure on an ongoing basis. It is possible that the Company may incur goodwill impairment charges at any reporting units containing goodwill in future periods if adverse changes in their business or operating environments occur. See Note 10—Goodwill and Other Intangible Assets included in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information.

Capital Resources and Liquidity

Overview

As of December 31, 2014, the Company had unrestricted cash and cash equivalents of $1.5 billion, of which $507 million was held at the Parent Company and qualified holding companies. The Company also had $709 million in short term investments, held primarily at subsidiaries. In addition, we had restricted cash and debt service reserves of $694 million. The Company also had non-recourse and recourse aggregate principal amounts of debt outstanding of $15.6 billion and $5.3 billion, respectively. Of the approximately $2.0 billion of our current non-recourse debt, $1.1 billion was presented as such because it is due in the next twelve months and $858 million relates to debt considered in default due to covenant violations. The defaults are not payment defaults, but are instead technical defaults triggered by failure to comply with other covenants and/or other conditions such as (but not limited to) failure to meet information covenants, complete construction or other milestones in an allocated time, meet certain minimum or maximum financial ratios, or other requirements contained in the non-recourse debt documents of the Company.

We expect such current maturities will be repaid from net cash provided by operating activities of the subsidiary to which the debt relates or through opportunistic refinancing activity or some combination thereof. Approximately $151 million of our recourse debt matures within the next twelve months, which we expect to repay using a combination of cash on hand at the Parent Company, net cash provided by operating activities and/or net proceeds from the issuance of new debt at the Parent Company.

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

Given our long-term debt obligations, the Company is subject to interest rate risk on debt balances that accrue interest at variable rates. When possible, the Company will borrow funds at fixed interest rates or hedge its variable rate debt to fix its interest costs on such obligations. In addition, the Company has historically tried to maintain at least 70% of its consolidated long-term obligations at fixed interest rates, including fixing the interest rate through the use of interest rate swaps. These efforts apply to the notional amount of the swaps compared to the amount of related underlying debt. Presently, the Parent Company's only material un-hedged exposure to variable interest rate debt relates to indebtedness under its senior secured credit facility and floating rate senior unsecured notes due 2019. On a consolidated basis, of the Company's $15.6 billion of total non-recourse debt outstanding as of December 31, 2014, approximately $3.9 billion bore interest at variable rates that were not subject to a derivative instrument which fixed the interest rate.

In addition to utilizing non-recourse debt at a subsidiary level when available, the Parent Company provides a portion, or in certain instances all, of the remaining long-term financing or credit required to fund development, construction or acquisition of a particular project. These investments have generally taken the form of equity investments or intercompany loans, which are subordinated to the project's non-recourse loans. We generally obtain the funds for these investments from our cash flows from operations, proceeds from the sales of assets and/or the proceeds from our issuances of debt, common stock and other securities. Similarly, in certain of our businesses, the Parent Company may provide financial guarantees or other credit support for the benefit of counterparties who have entered into contracts for the purchase or sale of electricity, equipment or other services with our subsidiaries or lenders. In such circumstances, if a business defaults on its payment or supply obligation, the Parent Company will be responsible for the business' obligations up to the amount provided for in the relevant guarantee or other credit support. At December 31, 2014, the Parent Company had provided outstanding financial and performance-related guarantees or other credit support commitments to or for the benefit of our businesses, which were limited by the terms of the agreements, of approximately $417 million in aggregate (excluding those collateralized by letters of credit and other obligations discussed below).

As a result of the Parent Company's below investment grade rating, counterparties may be unwilling to accept our general unsecured commitments to provide credit support. Accordingly, with respect to both new and existing commitments, the Parent Company may be required to provide some other form of assurance, such as a letter of credit, to backstop or replace our credit support. The Parent Company may not be able to provide adequate assurances to such counterparties. To the extent we are required and able to provide letters of credit or other collateral to such counterparties, this will reduce the amount of credit available to us to meet our other liquidity needs. At December 31, 2014, we had $61 million in letters of credit outstanding, provided under our senior secured credit facility, and $74 million in cash collateralized letters of credit outstanding outside of our senior secured credit facility. These letters of credit operate to guarantee performance relating to certain project development activities and business operations. During the year ended December 31, 2014, the Company paid letter of credit fees ranging from 0.2% to 2.5% per annum on the outstanding amounts.

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

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

As of December 31, 2014, the Company had approximately $293 million and $31 million of accounts receivable related to certain of its generation businesses in Argentina and the Dominican Republic and its utility businesses in Brazil classified as “Noncurrent assets—other” and “Current assets—Accounts receivable,” respectively. The noncurrent portion primarily consists of accounts receivable in Argentina that, pursuant to amended agreements or government resolutions, have collection periods that extend beyond December 31, 2015, or one year from the latest balance sheet date. The majority of Argentinian receivables have been converted into long-term financing for the construction of power plants. See Note 7—Financing Receivables included in Item 8.—Financial Statements and Supplementary Data and Item 1.—Business—Regulatory Matters—Argentina of this Form 10-K for further information.

Consolidated Cash Flows

During the year ended December 31, 2014, cash and cash equivalents decreased $103 million to $1.5 billion. The decrease in cash and cash equivalents was due to $1.8 billion of cash provided by operating activities, $656 million of cash used in investing activities, $1.3 billion of cash used in financing activities, an unfavorable effect of foreign currency exchange rates on cash of $51 million and a $75 million decrease in cash of discontinued and held-for-sale businesses.

	2014	2013	2012	$ Change 2014 vs. 2013	2013 vs. 2012
	(in millions)				
Net cash provided by (used in) operating activities	$1,791	$2,715	$2,901	$(924)	$(186)
Net cash provided by (used in) investing activities	(656)	(1,774)	(895)	1,118	(879)
Net cash provided by (used in) financing activities	(1,262)	(1,136)	(1,867)	(126)	731

Operating Activities

2014 Cash Flows from Operating Activities

For the year ended December 31, 2014 compared to the year ended December 31, 2013, the net decrease in cash flows from operating activities of $924 million, or 34% to $1.8 billion was primarily the result of the following:

- Brazil — decrease of $549 million primarily driven by higher tax payments of $244 million across the region and higher energy purchases in excess of collections resulting from poor hydrology of $153 million and $84 million at the Utilities and Tietê, respectively;
- MCAC — a decrease of $184 million primarily driven by a non-recurring $90 million settlement received in 2013 related to a fuel contract amendment and $12 million lower collections in Dominican Republic, as well as higher energy purchases of $46 million in Panama, and;
- Europe — a decrease of $180 million primarily due to lower collections of $56 million at Maritza in Bulgaria and higher working capital requirements of $52 million in Northern Ireland in the U.K.

Operating cash flow of $1.8 billion for the year ended December 31, 2014 resulted primarily from net income and adjustments for non-cash items (principally depreciation and amortization, gain from sale of assets and investments, and impairment expense), which was partially offset by a net use of cash from changes in operating assets and liabilities of $1.0 billion due to the following:

- an increase of $723 million in other assets primarily related to increased regulatory assets at Eletropaulo and Sul resulting from higher priced energy purchases recoverable through future tariffs as well as an increase at Alicura related to the recognition of interest associated with the FONINVEMEM agreement;
- an increase of $520 million in accounts receivable primarily related to higher sales at Eletropaulo and Sul and lower collections at Maritza; and
- a decrease of $89 million in net income tax and other tax payables primarily for payments of income taxes in excess of accruals of new current tax liabilities; partially offset by
- an increase of $516 million in other liabilities primarily related to an increase in regulatory liabilities at Eletropaulo and Sul partially offset by pension contributions at IPL and payments for share-based compensation issuance withholding tax and termination of a derivative contract at the Parent Company.

2013 Cash Flows from Operating Activities

For the year ended December 31, 2013 compared to the year ended December 31, 2012, the net decrease in cash flows from operating activities of $186 million, or 6% to $2.7 billion was primarily the result of the following:

- US — an increase of $74 million primarily due to a bankruptcy settlement payment of the New York entities in 2012 and the proceeds from the PPA termination at Beaver Valley in January 2013;
- Andes — a decrease of $276 million primarily driven by higher working capital requirements;
- Brazil — a decrease of $106 million primarily related to lower collections and higher energy purchases at Sul, partially offset by the recovery of deferred costs from ANEEL, rate regulator, lower transmission costs and regulatory charges at Eletropaulo;
- MCAC — an increase of $185 million primarily driven by a $90 million settlement received related to an amendment to a fuel contract and lower working capital requirements; and
- Asia — a decrease of $85 million primarily driven by higher working capital requirements and lower operating results at Masinloc.

Operating cash flow of $2.7 billion for the year ended December 31, 2013 resulted primarily from net loss and adjustments for non-cash items (principally gain and losses on sales and disposals, impairment charges, depreciation and amortization, and deferred income taxes), which was partially offset by a net use of cash from changes in operating assets and liabilities of $76 million due to the following:

- a decrease of $725 million in accounts payable and other current liabilities primarily at Eletropaulo and Sul due to lower costs and a decrease in regulatory liabilities and at Uruguaiana primarily related to the extinguishment of a liability as well as lower generation and higher payments to fuel supplier at Kelanitissa;
- an increase of $103 million in other assets primarily due to an increase in noncurrent regulatory assets at Eletropaulo and Sul, resulting from higher priced energy purchases which are recoverable through future tariffs and an increase at Alicura related to the recognition of interest associated to FONINVEMEM agreement, partially offset by a decrease in noncurrent regulatory assets at IPL related to the annual adjustment to pension benefits based on the actuarial valuation; partially offset by
- a decrease of $358 million in prepaid expenses and other current assets mainly due to a decrease in current regulatory assets, for the recovery of prior period tariff cycle energy purchases and regulatory charges at Eletropaulo;
- a decrease of $146 million in accounts receivable primarily related to lower tariffs at Eletropaulo combined with lower tariff and reduced consumption at Sul as well as lower revenue offset by higher collections at Kelanitissa, partially offset by lower collections at Maritza;
- an increase of $137 million in other liabilities primarily due to an increase in noncurrent regulatory liabilities at Eletropaulo partially offset by a decrease in pension liability at IPL; and
- a increase of $95 million in net income tax and other tax payables primarily due to accruals for new current tax liabilities offset by payments of income taxes.

2012 Cash Flows from Operating Activities

Net cash provided by operating activities was $2.9 billion for the year ended December 31, 2012. Operating cash flow resulted primarily from net income and adjustments for non-cash items (principally depreciation and amortization, contingencies, deferred income taxes, losses on the extinguishment of debt, gains and losses on sales and disposals, and impairment charges), as well as a net source of cash from changes in operating assets and liabilities of $68 million due to the following:

- an increase of $589 million in other assets primarily due to an increase in noncurrent regulatory assets at Eletropaulo, resulting from higher priced energy purchases, regulatory charges and transmission costs which are recoverable through future tariffs and the establishment of a noncurrent note receivable at Cartagena in Spain following the arbitration settlement, prior to its deconsolidation;
- an increase of $241 million in accounts receivable primarily due to lower collection Eletropaulo and Andres as well as an increase in revenue at Sul and Kelanitissa;
- a decrease of $47 million net income tax payables and other tax payables primarily for the payment of income taxes in excess of the accrual of new tax liabilities; partially offset by
- an increase of $335 million in other liabilities primarily explained by an increase in noncurrent regulatory liabilities at Eletropaulo related to the tariff reset;
- an increase of $330 million in accounts payable and other current liabilities primarily at Eletropaulo due to an increase in current regulatory liabilities driven by the tariff reset, offset by a decrease in other current liabilities arising from value-added tax payables; and
- a decrease of $120 million in prepaid expenses and other current assets mainly due to the recovery of value-added taxes at our construction projects in Chile.

Investing Activities

2014 Cash Flows from Investing Activities

Net cash used in investing activities was $656 million for the year ended December 31, 2014 primarily attributable to the following:

- Capital expenditures of $2.0 billion consisting of $1.2 billion of growth capital expenditures and $865 million of maintenance and environmental capital expenditures. Material expenditures by business are as follows:

Growth capital expenditures included amounts at Gener of $399 million, Eletropaulo of $146 million, IPL of $126 million, Mong Duong of $111 million, Jordan of $72 million, Maritza of $62 million, DPL of $46 million, Sul of $45 million and Panama of $42 million;

Maintenance and environmental capital expenditures included amounts at IPL of $265 million, Eletropaulo of $90 million, Gener of $89 million, Tietê of $80 million, DPL of $65 million, Sul of $54 million and Altai of $43 million;

- Acquisitions, net of cash acquired of $728 million consisted primarily of an acquisition at Gener in the second quarter for the remaining 50% interest in our equity investment in Guacolda, of which 50% less one share was subsequently sold during the same quarter. See Note 8—Investment in and Advances to Affiliates in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for further information;
- Purchases of short-term investments, net of sales of $120 million including amounts at Brasiliana Energia of $81 million and Tietê of $63 million offset by net sales at Eletropaulo of $39 million; partially offset by
- Proceeds from the sale of businesses, net of cash sold of $1.8 billion including $730 million at Gener related to the sale of 50% less one share of our interest in Guacolda, $436 million for the sale of 45% of our equity interest in Masinloc, $174 million related to the the sale of AES' interest in Silver Ridge Power's assets in Bulgaria, France, Greece, India and the United States, $158 million related to the UK Wind Sale, $156 million from the sale of our businesses in Cameroon and $125 million for the sale of Entek, our equity investment in Turkey; and
- Decreases in restricted cash, debt service reserve and other assets of $419 million including amounts of $98 million primarily related to the Alstom settlement repayment at Maritza, $96 million at the Parent Company pertaining to letter of credit reductions for Jordan and Mong Duong development projects, as well as project debt refinancing of $70 million and $45 million at Angamos and Southland, respectively.

2013 Cash Flows from Investing Activities

Net cash used in investing activities was $1.8 billion for the year ended December 31, 2013 primarily attributable to the following:

- Capital expenditures of $2.0 billion consisting of $1.1 billion of growth capital expenditures and $934 million of maintenance and environmental capital expenditures.

Growth capital expenditures included amounts at Gener of $317 million, Eletropaulo of $223 million, Jordan of $200 million, Sul of $72 million, Mong Duong of $48 million, DPL of $40 million, Sixpenny Wood of $25 million, Altai of

$21 million, Yelvertoft of $20 million and Kribi of $20 million;

Maintenance and environmental expenditures included amounts at IPL of $246 million, Eletropaulo of $138 million, Tietê of $94 million, Gener of $92 million, DPL of $76 million, Sul of $61 million and Altai of $43 million; partially offset by

- Proceeds from the sale of businesses, net of cash sold of $170 million including $110 million for the sale of the Ukraine businesses, $31 million for the sale of our 10% equity interest in Trinidad and $24 million for the sale of our remaining interest in Cartagena.

Financing Activities

2014 Cash Flows from Financing Activities

Net cash used in financing activities was $1.3 billion for the year ended December 31, 2014 primarily attributable to the following:

- Repayments of recourse and non-recourse debt of $5.6 billion including amounts at the Parent Company of $2.1 billion, Gener of $905 million, Angamos of $780 million, DPL of $364 million, Southland of $188 million, Chivor of $165 million, Tietê of $132 million, $114 million related to the UK Wind sale, Eletropaulo of $110 million and Warrior Run of $109 million;
- Payments for financed capital expenditures were $528 million including $310 million at Mong Duong, $143 million at Cochrane and $30 million at Changuinola;
- Distributions to noncontrolling interests of $485 million including amounts at Tietê of $188 million, Brasiliana Energia of $69 million, Gener of $66 million and Buffalo Gap of $45 million;
- Purchase of treasury stock of $308 million at the Parent Company; partially offset by
- Issuances of recourse and non-recourse debt of $5.7 billion including new issuances at the Parent Company of $1.5 billion, Angamos of $800 million, Gener of $700 million, Mong Duong of $364 million, Tietê of $318 million, Cochrane of $305 million, US Generation Holdings of $299 million, Eletropaulo of $253 million, DPL of $200 million and Sul of $185 million.

2013 Cash Flows from Financing Activities

Net cash used in financing activities was $1.1 billion for the year ended December 31, 2013 primarily attributable to the following:

- Repayments of recourse and non-recourse debt of $4.6 billion including amounts at the Parent Company of $1.2 billion, DPL of $948 million, Masinloc of $560 million, Changuinola of $412 million, Tietê of $396 million, Caess of $301 million, IPL of $110 million, Warrior Run of $100 million, Puerto Rico of $73 million, Maritza of $57 million, Southland of $54 million, Sonel of $47 million and Sul of $44 million;
- Payments for financed capital expenditures were $591 million primarily at Mong Duong for payments to the contractors which took place more than three months after the associated equipment was purchased or work performed;
- Distributions to noncontrolling interests of $557 million including amounts at Tietê of $205 million, Brasiliana of $128 million, Gener of $62 million and Buffalo Gap of $54 million;
- The purchase of treasury stock at the Parent Company was $322 million;
- Payments for financing fees of $176 million including amounts at Gener of $54 million including amounts at the Alto Maipo and Cochrane projects, Mong Duong of $28 million and Eletropaulo of $25 million; partially offset by
- Issuances of recourse and non-recourse debt of $5.0 billion including amounts of $750 million at the Parent Company, Gener of $707 million including amounts at the Cochrane and Alto Maipo projects, DPL of $645 million, Masinloc of $500 million, Tietê of $496 million, Mong Duong of $471 million, Changuinola of $420 million, Caess of $310 million, Jordan of $180 million, IPL of $170 million and Sul of $153 million; and
- Contributions from noncontrolling interests of $210 million including amounts at Gener of $109 million including amounts at the Cochrane and Alto Maipo projects and at Mong Duong of $77 million.

Proportional Free Cash Flow (a non-GAAP measure)

We define Proportional free cash flow as cash flows from operating activities less maintenance capital expenditures (including non-recoverable environmental capital expenditures), adjusted for the estimated impact of noncontrolling interests.

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

The GAAP measure most comparable to proportional free cash flow is cash flows from operating activities. We believe that proportional free cash flow better reflects the underlying business performance of the Company, as it measures the cash generated by the business, after the funding of maintenance capital expenditures, that may be available for investing or repaying debt or other purposes. Factors in this determination include the impact of noncontrolling interests, where AES consolidates the results of a subsidiary that is not wholly owned by the Company. The presentation of free cash flow has material limitations. Proportional free cash flow should not be construed as an alternative to cash from operating activities, which is determined in accordance with GAAP. Proportional free cash flow does not represent our cash flow available for discretionary payments because it excludes certain payments that are required or to which we have committed, such as debt service requirements and dividend payments. Our definition of proportional free cash flow may not be comparable to similarly titled measures presented by other companies.

	2014	2013	2012
Calculation of Maintenance Capital Expenditures for Free Cash Flow Reconciliation Below:	(in millions)		
Maintenance Capital Expenditures	$666	$760	$968
Environmental Capital Expenditures	241	211	75
Growth Capital Expenditures	1,637	1,608	1,227
Total Capital Expenditures	$2,544	$2,579	$2,270
Consolidated			
Net cash provided by operating activities	$1,791	$2,715	$2,901
Less: Maintenance Capital Expenditures, net of reinsurance proceeds	666	760	923
Less: Non-recoverable Environmental Capital Expenditures	78	101	66
Free Cash Flow	$1,047	$1,854	$1,912
Reconciliation of Proportional Operating Cash Flow			
Net cash provided by operating activities	$1,791	$2,715	$2,901
Less: Proportional Adjustment Factor[1]	359	834	966
Proportional Operating Cash Flow	$1,432	$1,881	$1,935
Proportional			
Proportional Operating Cash Flow	$1,432	$1,881	$1,935
Less: Proportional Maintenance Capital Expenditures, net of reinsurance proceeds[1]	485	535	634
Less: Proportional Non-recoverable Environmental Capital Expenditures[1]	56	75	51
Proportional Free Cash Flow	$891	$1,271	$1,250

(1) The proportional adjustment factor, proportional maintenance capital expenditures (net of reinsurance proceeds), and proportional non-recoverable environmental capital expenditures are calculated by multiplying the percentage owned by non-controlling interests for each entity by its corresponding consolidated cash flow metric and adding up the resulting figures. For example, the Company owns approximately 71% of AES Gener, its subsidiary in Chile. Assuming a consolidated net cash flow from operating activities of $100 from AES Gener, the proportional adjustment factor for AES Gener would equal approximately $29 (or $100 x 29%). The Company calculates the proportional adjustment factor for each consolidated business in this manner and then adds these amounts together to determine the total proportional adjustment factor used in the reconciliation. The proportional adjustment factor may differ from the proportion of income attributable to non-controlling interests as a result of (a) non-cash items which impact income but not cash and (b) AES' ownership interest in the subsidiary where such items occur.

Proportional Free Cash Flow for the year ended December 31, 2014 compared to the year ended December 31, 2013 decreased $380 million, driven primarily by the following SBUs and key operating drivers excluding intercompany related transactions pertaining to interest, tax sharing and charges for management fee and transfer pricing:

- MCAC — $152 million decrease primarily driven by a non-recurring $90 million settlement received in 2013 related to a fuel contract amendment and $30 million lower collections in Dominican Republic, as well as higher energy purchases of $22 million in Panama;

- Europe — $149 million decrease primarily driven by $56 million of lower collections in Bulgaria and $52 million of lower operating margins and higher working capital in Northern Ireland in the U.K.;
- Brazil — $103 million decrease primarily driven by higher tax payments of $100 million across the region and higher energy purchases in excess of collections resulting from poor hydrology of $10 million and $20 million at the Utilities and Tietê, respectively;
- US — $46 million decrease driven by $46 million proceeds from the PPA termination at Beaver Valley in 2013 and $41 million of higher working capital at DPL, partially offset by $52 million of lower maintenance capital expenditures at the U.S. Utilities;
- Asia — $19 million decrease driven primarily by lower margins at Kelanitissa; and
- Andes — $13 million decrease primarily related to $51 million in Chile driven by $28 million of VAT receivable timing and an interest rate swap payment of $18 million as well as $28 million in Argentina primarily due to an increase in interest receivables. These results were partially offset by an increase of $67 million at Chivor in Colombia primarily due to higher margins.

These decreases were partially offset by:

- Corporate — $98 million increase primarily driven by lower Parent interest of $69 million.

Proportional Free Cash Flow for the year ended December 31, 2013 compared to the year ended December 31, 2012 increased $21 million, driven primarily by the following SBUs and key operating drivers excluding intercompany related transactions pertaining to interest, tax sharing and charges for management fee and transfer pricing:

- MCAC — $197 million increase driven by higher operating cash flow, as a result of a $90 million settlement related to an amendment to a fuel contract and lower working capital requirements, and
- US — $110 million increase as a result of higher operating cash flow from a settlement received related to the bankruptcy of the New York entities in 2012 and the proceeds from the PPA termination at Beaver Valley in January 2013, as well as $48 million due to lower capital expenditures.

These increases were partially offset by:

- Andes — $193 million increase driven by lower operating cash flow from higher working capital requirements; and
- Asia — $76 million decrease largely due to lower operating cash flow from higher working capital requirements and lower operating results at Masinloc.

Parent Free Cash Flow (a non-GAAP measure)

The Company defines Parent Free Cash Flow as dividends and other distributions received from our operating businesses less certain cash costs at the Parent Company level, primarily interest payments, overhead, and development costs. Parent Free Cash Flow is used to fund shareholder dividends, share repurchases, growth investments, recourse debt repayments, and other uses by the Parent Company. Refer to Item 1—Business—Overview for further discussion of the Parent Company's capital allocation strategy.

Parent Company Liquidity

The following discussion of Parent Company Liquidity has been included because we believe it is a useful measure of the liquidity available to The AES Corporation, or the Parent Company, given the non-recourse nature of most of our indebtedness. Parent Company Liquidity as outlined below is a non-GAAP measure and should not be construed as an alternative to cash and cash equivalents which are determined in accordance with GAAP, as a measure of liquidity. Cash and cash equivalents are disclosed in the consolidated statements of cash flows. Parent Company Liquidity may differ from similarly titled measures used by other companies. The principal sources of liquidity at the Parent Company level are:

- dividends and other distributions from our subsidiaries, including refinancing proceeds;
- proceeds from debt and equity financings at the Parent Company level, including availability under our credit facility; and
- proceeds from asset sales.

Cash requirements at the Parent Company level are primarily to fund:

- interest;
- principal repayments of debt;
- acquisitions;
- construction commitments;
- other equity commitments;
- common stock repurchases;
- taxes;
- Parent Company overhead and development costs; and
- dividends on common stock.

The Company defines Parent Company Liquidity as cash available to the Parent Company plus available borrowings under existing credit facility. The cash held at qualified holding companies represents cash sent to subsidiaries of the Company domiciled outside of the U.S. Such subsidiaries have no contractual restrictions on their ability to send cash to the Parent Company. Parent Company Liquidity is reconciled to its most directly comparable U.S. GAAP financial measure, “cash and cash equivalents,” at December 31, 2014 and 2013 as follows:

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Parent Company Liquidity	2014	2013
	(in millions)	
Consolidated cash and cash equivalents	$1,539	$1,642
Less: Cash and cash equivalents at subsidiaries	1,032	1,510
Parent and qualified holding companies' cash and cash equivalents	507	132
Commitments under Parent credit facility	800	800
Less: Letters of credit under the credit facility	(61)	(1)
Borrowings available under Parent credit facility	739	799
Total Parent Company Liquidity	$1,246	$931

The Company paid dividends of $0.20 per share to its common stockholders during the year ended December 31, 2014. While we intend to continue payment of dividends and believe we will have sufficient liquidity to do so, we can provide no assurance we will be able to continue the payment of dividends.

Recourse Debt:

Our recourse debt at year-end was approximately $5.3 billion and $5.7 billion in 2014 and 2013, respectively. See Note 12—Debt in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for additional detail.

While we believe that our sources of liquidity will be adequate to meet our needs for the foreseeable future, this belief is based on a number of material assumptions, including, without limitation, assumptions about our ability to access the capital markets (see Key Trends and Uncertainties, Global Economic Conditions), the operating and financial performance of our subsidiaries, currency exchange rates, power market pool prices, and the ability of our subsidiaries to pay dividends. In addition, our subsidiaries' ability to declare and pay cash dividends to us (at the Parent Company level) is subject to certain limitations contained in loans, governmental provisions and other agreements. We can provide no assurance that these sources will be available when needed or that the actual cash requirements will not be greater than anticipated. See Item 1A.—Risk Factors—The AES Corporation is a holding company and its ability to make payments on its outstanding indebtedness, including its public debt securities, is dependent upon the receipt of funds from its subsidiaries by way of dividends, fees, interest, loans or otherwise, of this Form 10-K.

Various debt instruments at the Parent Company level, including our senior secured credit facility, contain certain restrictive covenants. The covenants provide for, among other items:

- limitations on other indebtedness, liens, investments and guarantees;
- limitations on dividends, stock repurchases and other equity transactions;
- restrictions and limitations on mergers and acquisitions, sales of assets, leases, transactions with affiliates and off-balance sheet and derivative arrangements;
- maintenance of certain financial ratios; and
- financial and other reporting requirements.

As of December 31, 2014, we were in compliance with these covenants at the Parent Company level.

Non-Recourse Debt

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

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

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

Some of our subsidiaries are currently in default with respect to all or a portion of their outstanding indebtedness. The total non-recourse debt classified as current in the accompanying consolidated balance sheets amounts to $2.0 billion. The portion of current debt related to such defaults was $858 million at December 31, 2014, all of which was non-recourse debt related to two subsidiaries — Maritza and Kavarna. See Note 12—Debt in Item 8.—Financial Statements and Supplementary Data of this Form 10-K for additional detail.

None of the subsidiaries that are currently in default are subsidiaries that met the applicable definition of materiality under AES' corporate debt agreements as of December 31, 2014 in order for such defaults to trigger an event of default or permit acceleration under AES' indebtedness. However, as a result of additional dispositions of assets, other significant reductions in asset carrying values or other matters in the future that may impact our financial position and results of operations or the financial position of the individual subsidiary, it is possible that one or more of these subsidiaries could fall within the definition of a "material subsidiary" and thereby upon an acceleration trigger an event of default and possible acceleration of the indebtedness under the Parent Company's outstanding debt securities. A material subsidiary is defined in the Company's senior secured revolving credit facility as any business that contributed 20% or more of the Parent Company's total cash distributions from businesses for the four most recently completed fiscal quarters. As of December 31, 2014, none of the defaults listed above individually or in the aggregate results in or is at risk of triggering a cross-default under the recourse debt of the Company.

Contractual Obligations and Parent Company Contingent Contractual Obligations

A summary of our contractual obligations, commitments and other liabilities as of December 31, 2014 is presented in the table below, which excludes any businesses classified as discontinued operations or held-for-sale (in millions):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years	Other	Footnote Reference[5]
Debt Obligations[1]	$20,858	$2,144	$3,623	$3,282	$11,809	$—	12
Interest Payments on Long-Term Debt[2]	10,349	1,201	2,088	1,645	5,415	—	n/a
Capital Lease Obligations[3]	159	10	20	20	109	—	13
Operating Lease Obligations[3]							