

AES CORP  
Form 10-K  
February 27, 2013  
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**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, 2012**

**-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)

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**Delaware**  
(State or other jurisdiction of  
incorporation or organization)

**54 1163725**  
(I.R.S. Employer  
Identification No.)

**4300 Wilson Boulevard, Arlington, Virginia**  
(Address of principal executive offices)

**22203**  
(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 ☐ No ☒

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer 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 ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐  
(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 ☐ No ☒

The aggregate market value of the voting and non-voting common equity held by non-affiliates on June 29, 2012, the last business day of the Registrant's most recently completed second fiscal quarter (based on the closing sale price of \$12.73 of the Registrant's Common Stock, as reported by the New York Stock Exchange on such date) was approximately \$7.94 billion.

The number of shares outstanding of the Registrant's Common Stock, par value \$0.01 per share, on February 20, 2013, was 745,763,563.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of Registrant's Proxy Statement for its 2013 annual meeting of stockholders are incorporated by reference in Parts II and III



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**THE AES CORPORATION**  
**FISCAL YEAR 2012 FORM 10-K**  
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### **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 term The AES Corporation and Parent Company refers 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;

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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 projects and our ability to finance, construct and begin operating our greenfield projects on schedule and within budget;

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our ability to enter into long-term contracts, which limit volatility in our results of operations and cash flow, such as Power Purchase Agreements ( PPA ), 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, low levels of wind or sunlight for our wind and solar businesses, and the occurrence of difficult hydrological conditions for our hydro-power plants, as well as hurricanes and other storms and disasters;

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 greenhouse gas 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, whether with or without adequate compensation;

our ability to achieve expected rate increases 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, deregulation of wholesale power markets and its effects on competition, the ability to recover net utility assets and other potential stranded costs by our utilities, the establishment of a regional transmission organization that includes our utility service territory, the application of market power criteria by the Federal Energy Regulatory Commission, changes in law resulting from new federal energy legislation and changes in political or regulatory oversight or incentives affecting our wind business, our solar joint venture, our other renewables projects and our initiatives in greenhouse gas 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, greenhouse gas 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;

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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;

the performance of business and asset acquisitions, including our recent acquisition of DPL Inc., and our ability to successfully integrate and operate acquired businesses and assets, such as DPL, and effectively realize anticipated benefits; and

information security breaches.



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

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

### ***Strategy***

Our strategic plan intends to maximize the risk-adjusted value of our portfolio for shareholders through our efforts to execute upon the following objectives:

First, we are managing our portfolio of generation and utility businesses to create value for our stakeholders, including customers and shareholders, through safe, reliable, and sustainable operations and effective cost management.

Second, we are driving our operating business to manage capital more effectively and to increase the amount of discretionary cash available for deployment into debt repayment, growth investments, shareholder dividends, and share buybacks.

Third, we are realigning our geographic focus. To this end, we will continue to exit markets where we do not have a competitive advantage or where we are unable to earn a fair risk-adjusted return relative to monetization alternatives. In addition, we will focus our growth investments on platform expansions or opportunities to expand our existing operations.

Finally, we are working to reduce the cash flow and earnings volatility of our businesses by proactively managing our currency, commodity and political risk exposures, mostly through contractual and regulatory mechanisms, as well as commercial hedging activities. We also will continue to limit our risk by utilizing non-recourse project financing for the majority of our businesses.

### ***Business Lines & Strategic Business Units***

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.

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The following table summarizes our generation business by capacity and facilities and our utilities business by customers, capacity and facilities for each SBU.

SBU	Generation Capacity (Gross MW)	Generation Facilities	Utility Customers	Utility GWh	Utility Businesses
US					
Generation	6,281	21			
Utilities	7,517	18	1.1 million	31,777	2
Andes					
Generation	7,740	30			
Brazil					
Generation	3,298	13			
Utilities			7.7 million	54,408	2
MCAC					
Generation	3,860	16			
Utilities			1.2 million	3,642	4
EMEA					
Generation	8,460	22			
Utilities	936	11	2.2 million	11,235	4
Asia					
Generation	1,337	4			
	39,429 <sup>(1)</sup>	135	12.2 million	101,062	12

<sup>(1)</sup> 30,251 proportional MW. Proportional MW is equal to gross MW times AES' equity ownership percentage.

**Generation**

We currently own and/or operate a generation portfolio of approximately 31,000 MW, excluding the generation capabilities of our integrated utilities. Our generation fleet is diversified by fuel type. As a percentage of installed capacity, coal and natural gas each account for 36% and 35%, respectively, of our generating capacity. Renewables, primarily hydro, wind and solar, represent 25% of our generating capacity and oil, diesel and petroleum coke comprise the rest.

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 medium- or long-term contracts. Our contract sales have a term of at least 2 years, but the majority of our contracts are much longer in duration, from 5 to 25 years. Our generation businesses use two contracting strategies, a single contract strategy and a portfolio contract strategy.

Single contracts generally have terms of 10 to 25 years with either a regulated or large industrial unregulated customer. Under these contracts, our generation businesses recover variable costs including fuel and variable operations and maintenance ( "O&M" ) costs, either through contractual pass-throughs or tolling arrangements (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. Our generation businesses in the United States, Bulgaria, and Vietnam are some examples of where we have used the single-contract approach.



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Some of our businesses utilize a portfolio contract strategy. Under this approach, the business sells its output to several different customers with the aim of contracting a significant portion of total output and we generally contract for a period of 2 to 10 years with a regulated customer (utility, municipal or cooperative) or unregulated free client (a customer that is allowed under the local regulatory regime to contract directly for its electricity needs). These contracts typically include a direct or indexation-based fuel pass-through. 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**). Examples of businesses with the portfolio contract strategy include AES Gener in Chile and Masinloc in the Philippines.

*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.

Thus, these contracts, or other commercial arrangements that we have made around or in addition to these contracts, 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 standards required in the contract. This important risk mitigation helps to limit the variability of the earnings and cash flows of the business.

*Short-Term Sales.* Our other generation businesses sell power and ancillary services under short-term contracts with a term of 2 years or less, 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, 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. An example of a business with short-term sales is our Kilroot facility in the United Kingdom.

*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 market typically receive capacity payments based on their availability in the market.

### *Plant Reliability and Flexibility*

Our contract and short-term sales provide incentives to our generation plants to optimally manage availability, operating efficiency and flexibility. Capacity payments under the single contract strategy are 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.

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### *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 using the single contract strategy, 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.

About one-third 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.

Roughly one-third of our generation plants are fueled by natural gas. Generally, we use gas from local supplies in each market. A few exceptions to this are AES Gener in Chile, our Uruguaiiana plant in Brazil, which resumed operations in February 2013, and the Dominican Republic, where we import Liquefied Natural Gas ( LNG ) to utilize in the local market.

Approximately five percent of our generation fleet utilizes oil, diesel and petroleum coke ( pet coke ) for fuel. Oil and diesel are sourced locally at prices indexed to international markets, while pet coke is largely sourced from Mexico and the U.S. The remaining portion of our portfolio is comprised mostly of hydro, wind and solar generation plants, which do not have significant fuel costs.

### *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 is determined by market competition and local dispatch and reliability rules.

### *Utilities*

AES 12 utility businesses distribute power to more than 12 million people in six countries. These businesses also include generation capacity totaling approximately 8,500 MW. These 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.

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### *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, Indianapolis Power & Light Company ( 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 many instances, the tariffs can be adjusted between scheduled regulatory resets pursuant to an inflation adjustment or another index. Customers with demand above a certain level are unregulated in some regulatory regimes and can choose to contract with generation companies directly and pay a wheeling fee, which is a fee 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 kilowatt hours ( kWh ) sales, after adjustments for weather variations, are affected by changes in local economic activity, energy efficiency 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 The Dayton Power & Light Company ( 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 of industrial customers; however, in Ohio, our native

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load customers 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, can leave and choose to 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 the construction, although our construction management team supervises the construction work to ensure that the project is completed within budget and meets the required safety, efficiency and productivity standards.

### ***Environmental Matters***

We are subject to various international, federal, state, and/or 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 and Environmental and Land Use Regulations* for further regulatory and environmental discussion.

### ***Renewables and Other Initiatives***

In recent years, as demand for renewable sources of energy has grown, we have also been developing and/or acquiring hydro, wind, and solar based renewable projects. Currently, we own interests in 9,691 MW (5,216 proportional MW) of renewable projects, including projects in operations and under construction. Currently, the majority of our renewable capacity is hydro-based, representing 84% of our renewable portfolio.

In 2005, we started investing in wind generation businesses and currently have 1,518 MW in operation. In addition, we have 36 MW under construction.

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In 2008, we formed a 50/50 joint venture with Riverstone to develop, own and operate solar installations. Since its launch, AES Solar has commenced commercial operations of 256 MW of solar projects in Bulgaria, France, Greece, India, Italy, Puerto Rico and Spain, and has 266 MW under construction in Bulgaria, France, Greece, India, Italy and the U.S.

None of these initiatives are currently material to our operations, however, there are risks associated with these initiatives, which are further described in Item 1A. *Risk Factors* of this Form 10-K.

### ***Strategic Business Units***

AES operates and manages its six SBUs under one Chief Operating Officer ( COO ). All SBUs include generation facilities and four include utility businesses. The Company measures the operating performance of its SBUs using adjusted pre-tax contribution ( adjusted PTC ), a non-GAAP measure (see definition below).

AES' primary sources of revenue, gross margin and adjusted PTC are from generation and utilities businesses. The contribution to adjusted PTC by SBU for the year ended December 31, 2012 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* for reconciliation.

We define Adjusted PTC as pre-tax 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) significant gains or losses due to dispositions and acquisitions of business interests, (d) significant 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 PTC in each SBU includes the effect of intercompany transactions with other SBUs other than interest and charges for certain management services.

### ***Risks***

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;



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risks associated with our ability to raise needed capital;

external risks associated with revenue and earnings volatility;

risks associated with our operations;

risks associated with governmental regulation and laws; and

risks associated with our disclosure controls and internal controls over financial reporting.

The categories of risk identified above are discussed in greater detail in Item 1A. *Risk Factors* of this Form 10-K. 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.

### ***Our Organization and Segments***

The management reporting structure is organized along the six SBUs led by our COO, who in turn reports to our Chief Executive Officer ( CEO ). Our CEO and COO are based in Arlington, Virginia. During the fourth quarter of 2012, the Company completed the restructuring of its operational management and reporting process into these six SBUs. For financial reporting purposes, the Company has identified eight reportable segments based on the six SBUs, which include:

US SBU

US Generation segment

US Utilities segment

Andes SBU

Andes Generation segment

Brazil SBU

Brazil Generation segment

Brazil Utilities segment

MCAC SBU

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MCAC Generation segment

EMEA SBU

EMEA Generation segment

Asia SBU

Asia Generation segment

*Corporate and Other* For financial reporting purposes the Company's EMEA and MCAC utilities as well as Corporate 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* for further discussion of the Company's segment structure used for financial reporting purposes.

AES Solar and certain other unconsolidated businesses are accounted for using the equity method of accounting. Therefore, their operating results are included in Net Equity in Earnings of Affiliates on the face of the Consolidated Statements of Operations, not in revenue and gross margin.

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Corporate and Other also includes costs related to corporate overhead which are not directly associated with the operations of our eight reportable segments and other intercompany charges such as self-insurance premiums which are fully eliminated in consolidation. See Note 17 *Segment and Geographic Information* in the Consolidated Financial Statements in Item 8 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 21 generation facilities and two integrated utilities in the United States. Our US operations accounted for 20%, 10% and 12% of consolidated AES gross margin and 19%, 10% and 13% of consolidated AES adjusted PTC (a non-GAAP measure) in 2012, 2011 and 2010, respectively. 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.

The following table provides highlights of our U.S. operations:

Generation Capacity	13,798 gross MW (13,664 proportional MW)
Utilities Penetration	1,107,000 customers (31,777 GWh)
Generation Facilities	21
Utility Businesses	2 integrated utilities (includes 18 generation plants)
Key Generation Businesses	Southland and Hawaii
Key Utility Businesses	IPL and DPL

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Operating installed capacity of our US SBU totals 13,798 MW, of which 29%, 28%, 27% and 16%, is located at our Southland, DPL, IPL, and additional U.S. generation facilities, respectively. IPL's parent, IPALCO Enterprises, Inc., and DPL Inc. are SEC registrants, and as such, follow public filing requirements of the Securities Exchange Act of 1934. Set forth in the table below is a list of our U.S. businesses:

Business	Location	Fuel	Gross MW	AES Equity Ownership (Percent, Rounded)	Year Acquired or Began Operation
Southland Alamitos	US CA	Gas	2,075	100%	1998
Southland Redondo Beach	US CA	Gas	1,392	100%	1998
Southland Huntington Beach	US CA	Gas	474	100%	1998
Shady Point	US OK	Coal	360	100%	1991
Buffalo Gap II <sup>(1)</sup>	US TX	Wind	233	100%	2007
Hawaii	US HI	Coal	208	100%	1992
Warrior Run	US MD	Coal	205	100%	2000
Buffalo Gap III <sup>(1)</sup>	US TX	Wind	170	100%	2008
Deepwater	US TX	Pet Coke	160	100%	1986
Wind Generation Facilities <sup>(2)</sup>	US	Wind	134	0%	2005
Beaver Valley	US PA	Coal	132	100%	1985
Buffalo Gap I <sup>(1)</sup>	US TX	Wind	121	100%	2006
Lake Benton I <sup>(1)</sup>	US MN	Wind	106	100%	2007
Armenia Mountain <sup>(1)</sup>	US PA	Wind	101	100%	2009
Laurel Mountain	US WV	Wind	98	100%	2011
Storm Lake II <sup>(1)</sup>	US IA	Wind	78	100%	2007
Mountain View I & II <sup>(1)</sup>	US CA	Wind	67	100%	2008
Condon <sup>(1)</sup>	US CA	Wind	50	100%	2005
Mountain View IV	US CA	Wind	49	100%	2012
Tehachapi	US CA	Wind	38	100%	2006
Palm Springs	US CA	Wind	30	100%	2005

6,281

<sup>(1)</sup> 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 Non-Controlling Interest in the Company's Consolidated Balance Sheet.

<sup>(2)</sup> AES operates these facilities through management or O&M agreements and owns no equity interest in these businesses. Set forth in the tables below is a list of our U.S. utilities and their generation facilities:

Business	Location	Approximate Number of Customers Served as of 12/31/2012	GWh Sold in 2012	AES Equity Interest (Percent, Rounded)	Year Acquired
DP&L	US OH	637,000	16,454	100%	2011
IPL	US IN	470,000	15,323	100%	2001
		1,107,000	31,777		

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<b>Business</b>	<b>Location</b>	<b>Fuel</b>	<b>Gross MW</b>	<b>AES Equity Interest (Percent, Rounded)</b>	<b>Year Acquired or Began Operation</b>
DP&L <sup>(1)</sup>	US OH	Coal/Diesel/Solar	3,818	100%	2011
IPL <sup>(2)</sup>	US IN	Coal/Gas/Oil	3,699	100%	2001
			7,517		

(1) DP&L wholly-owned plants: Hutchings, Tait Units 1-3 and diesels, Yankee Street, Yankee Solar, Monument and Sidney. DP&L jointly-owned plants: Beckjord Unit 6, Conesville Unit 4, East Bend Unit 2, 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 2,655 MW. DP&L's share of this generation capacity is approximately 111 MW. DP&L 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 U.S. facilities:

**US SBU Businesses*****U.S. Utilities******IPALCO***

**Business Description.** IPALCO owns all of the outstanding common stock of IPL. IPL is engaged primarily in generating, transmitting, distributing and selling electric energy to approximately 470,000 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 911,000. 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) and natural gas.

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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. IPL's net electric generation capacity for winter is 3,492 MW and net summer capacity is 3,353 MW.

*Market Structure.* IPL is one of many transmission system owner members in the Midwest Independent Transmission System Operator, Inc. (MISO). MISO is a regional transmission organization which maintains functional control over the combined transmission systems of its members and manages one of the largest energy and ancillary services markets in the U.S. IPL offers the available electricity production of each of its generation assets into the MISO day-ahead and real-time markets. MISO operates on a merit order dispatch, considering transmission constraints and other reliability issues to meet the total demand in the MISO region.

### *Regulatory Framework*

*Retail Ratemaking.* In addition to the regulations referred to below in U.S. Regulatory Matters, IPL is subject to regulation by the Indiana Utility Regulatory Commission (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 Fuel Adjustment Charges (FAC) and for the timely recovery of costs incurred to comply with environmental laws and regulations referred to as Environmental Compliance Cost Recovery Adjustment (ECCRA). See Senate Bill 251 discussion under *Other United States Environmental and Land Use Legislation and Regulations* later in this section. 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.

### *Environmental Matters*

*Mercury and Air Toxics Standards (MATS).* IPL management has developed a plan to comply with the MATS rule (discussed below). Most of IPL's coal-fired capacity has acid gas scrubbers or comparable control technologies; however, there are other improvements to these control technologies that are necessary to achieve compliance. IPL was successful in deferring IPL's compliance date to April 16, 2016, based on an extension granted by the Indiana Department of Environmental Management (IDEM).

IPL has reviewed the impact of the MATS rule and estimate additional expenditures related to this rule for environmental controls for IPL's baseload generating units to be approximately \$511 million through 2016 excluding demolition costs. In June 2012, IPL filed a petition and requested a Certificate of Public Convenience and Necessity (CPCN) to comply with the MATS rule. These filings detail the controls IPL plans to add to each of IPL's five baseload units, including four at IPL's Petersburg generating station and one at IPL's Harding Street generating station. IPL will seek and expect to recover through IPL's environmental rate adjustment mechanism, all operating and capital expenditures related to compliance; however, there can be no assurance that IPL will be successful in that regard. Recovery of these costs is expected through an Indiana statute, which allows for 100% recovery of qualifying costs through a rate adjustment mechanism. Funding for these capital expenditures is expected to be obtained from additional debt financing at IPL; equity contributions from AES; borrowing capacity on IPL's committed credit facilities; and cash generated from operating activities.

*National Pollution Discharge Elimination System (NPDES).* On August 28, 2012, IDEM issued NPDES permits to the IPL Petersburg, Harding Street, and Eagle Valley generating stations, which became effective in October 2012. IPL is conducting studies to determine what operational changes and/or additional equipment will

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be required to comply with the new limitation. 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. See Water Discharges discussion under *Other United States Environmental and Land Use Legislation and Regulations* for further details of NPDES later in this section.

*Replacement Generation.* The combination of existing and expected environmental regulations make it likely that IPL will temporarily or permanently retire or repower several of IPL's existing, primarily coal-fired, smaller and older generating units within the next several years. These units are not equipped with the advanced environmental control technologies needed to comply with existing and expected regulations, and collectively have made up less than 15% of IPL's net electricity generation over the past five years. IPL is continuing to evaluate available options for replacing this generation, which include modifying one or more of the units to use natural gas as the fuel source, building new units, purchasing existing units, joint ownership of generating units, purchasing electricity and capacity from a third party, or some combination of these options. Accordingly, in June 2012, IPL issued a request for proposals for 600 MW of replacement capacity and energy beginning in June 2017, which is intended to help IPL determine the best plan for replacement generation. Proposals from outside parties have been received and IPL is currently evaluating appropriate next steps. IPL's decision on which replacement options to pursue will be impacted by the ultimate timetable for implementation of the rule. IPL will seek and expect to recover IPL's costs associated with replacing the retired units, but no assurance can be given as to whether the IURC would approve such a request.

### *Key Financial Drivers*

IPL's ability to earn wholesale margin is influenced by wholesale prices for electricity, fuel prices and the availability of their generating assets. Retail demand also influences IPL's financial results. IPL's ability to recover expenses and earn a return on capital expenditures in a timely manner, as well as passage of new legislation or implementation of regulations, has an impact on the business. Local macroeconomic conditions, given that IPL has an exclusive territory, weather and energy efficiency also drive their retail demand.

### *DPL Inc.*

*Business Description.* DPL is an energy holding company whose principal subsidiaries include DP&L, DPL Energy Resources, Inc. ( DPLER ) and DPL Energy, LLC ( DPLE ). DP&L generates, transmits, distributes and sells electricity to more than 513,000 customers in a 6,000 square mile area of West Central Ohio. DP&L, with certain other Ohio utilities and their affiliates, commonly owns seven coal-fired electric generating facilities, peaking generation units, solar generating facilities and numerous transmission facilities. DP&L also has one wholly-owned coal-fired plant, along with several gas-fired peaking plants. DPLER, a competitive retail marketer, sells retail electricity to more than 198,000 retail customers in Ohio and Illinois. Approximately 73,000 of these customers are also distribution customers of DP&L in Ohio. DPLE owns peaking generation units located in Ohio and Indiana. DP&L's wholly-owned plants and their share of the capacity of its jointly-owned plants and DPLE's wholly-owned peaking units aggregate to approximately 3,818 MW.

### *Market Structure*

*Customer Switching.* Since January 2001, electric customers within Ohio have been permitted to choose to purchase power under a contract with a Competitive Retail Electric Service Provider ( CRES Provider ) or continue to purchase power from their local utility under Standard Service Offer ( SSO ) rates established by

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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. The Public Utilities Commission of Ohio ( 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.

Overall power market prices, as well as government aggregation initiatives within DP&L's service territory, have led or may lead to the entrance of additional competitors in its service territory. During the year ended December 31, 2012, approximately 30% of customers representing 58% of 2012's overall energy usage (kWh) within DP&L's service area had elected to obtain their supply service from CRES Providers. DPL's subsidiary DPLER is a CRES Provider that has been marketing transmission and generation services to DP&L customers in Ohio and Illinois. During 2012, DPLER accounted for approximately 6,201 million kWh (76%) and other CRES Providers accounted for about 1,981 million kWh (24%) of the total 8,182 million kWh supplied by CRES Providers within DP&L's service territory. The volume supplied by DPLER represents 44% of DP&L's total distribution volume during 2012. DPL currently cannot determine the extent to which customer switching to CRES Providers will occur in the future and the impact this will have on its operations, but any additional switching could have a material adverse effect on its future results of operations, financial condition and cash flows.

*PJM Operations.* DP&L is a member of the PJM Interconnection, LLC ( PJM ). PJM is a Regional Transmission Organization ( RTO ) that operates the transmission systems owned by utilities operating in all or parts of Pennsylvania, New Jersey, Maryland, Delaware, D.C., Virginia, Ohio, West Virginia, Kentucky, North Carolina, Tennessee, Indiana and Illinois. PJM 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 Reliability Pricing Model ( RPM ) is PJM's capacity construct. The purpose of 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, three years in advance of the delivery year. DP&L's capacity has been located in the rest of the RTO area of PJM.

The PJM RPM auction for the 2015/16 period cleared at a per-MW price of \$136/MW-day for DP&L's RTO area. The clearing prices for the periods 2011/12, 2012/13, 2013/14 and 2014/15 were \$110/MW-day, \$16/MW-day, \$28/MW-day and \$126/MW-day, respectively, based on previous auctions. Based on the base residual auction prices, DP&L estimates that future gross RPM capacity revenue will be \$156 million, \$106 million and \$28 million for 2015, 2014 and 2013 calendar years, respectively. Future RPM auction results will be dependent not only on the overall supply and demand of generation and load, but may also be affected by load congestion as well as PJM's business rules relating to bidding for demand response and energy efficiency resources in the RPM capacity auctions.

### *Regulatory Framework*

*Retail Regulation.* DP&L is subject to regulation by the PUCO, which regulates its distribution services and facilities, retail rates and charges, reliability of service, compliance with renewable energy portfolio and 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,



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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, referred to as FAC and for the timely recovery of costs incurred to comply with alternative energy, renewable, energy efficiency, and economic development costs. These components function somewhat 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.* Retail generation has been deregulated in Ohio since 2001, which allows electric customers within Ohio to choose to purchase retail generation service under contract with CRES 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 either an Electric Security Plan (ESP) or Market Rate Offer (MRO) 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 tariff rate setting process. DP&L is permitted to recover its costs of providing distribution service as well as earn a regulated rate of return on assets, determined by the regulator, based on the utility's allowed regulated asset base, capital structure and cost of capital.

DP&L filed an ESP with the PUCO in 2012 requesting, among other things, a non-bypassable charge designed to recover \$137 million per year for five years from all customers. DP&L also requested approval of a switching tracker that would measure the incremental amount of switching over a base case and defer the lost value into a regulatory asset which would be recovered from all customers beginning in January 2014. The ESP further states that DP&L plans to file on or before December 31, 2013 its plan for legal separation of its generation assets as required by legislation. The ESP proposes a three-year, five-month transition to market, whereby a wholesale competitive bidding structure will be phased in to supply generation service to customers located in DP&L's service territory that have not chosen an alternative generation supplier. The PUCO authorized that DP&L's rates in effect at December 31, 2012 would continue until the new ESP rates go into effect.

### *Environmental Matters*

The EPA promulgated the Clean Air Interstate Rule (CAIR) to regulate emissions from existing power plants in the eastern U.S. This became known as the Cross-State Air Pollution Rule (CSAPR) and was vacated by the D. C. Circuit Court. If CSAPR were to be reinstated in its current form, DP&L does not expect any material capital costs for DP&L's plants, which would continue to operate as they currently have scrubbing equipment installed.

In relation to MATS, it is expected that DP&L has several units that are fully owned or jointly-owned that are expected to cease operations as a result of non-compliance with the requirements under MATS. For more information see *Other United States Environmental and Land Use Legislation and Regulations* discussion later in this section.

On January 7, 2013, Ohio EPA issued an NPDES permit for J.M. Stuart Station. DPL is analyzing the NPDES permit at this time. The uncertainties around the type of compliance and the cost that may be necessary to become compliant could be material to DPL. See *Water Discharges* section of *Other United States Environmental and Land Use Legislation and Regulations* later in this section for a further discussion.

### *Key Financial Drivers*

DPL's focus is on completing its current rate proceedings and working with all stakeholders to determine a fair and reasonable outcome, including an appropriate non-bypassable charge. Other key objectives are retaining customers under its regulated tariff and enhancing the competitiveness of its retail business, DPLER, to maintain and gain customers with an adequate margin. DPL's operating performance also varies with wholesale power prices, which are largely influenced by delivered gas prices, as well as movements in local coal prices and long-

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term capacity prices. Further, total demand for electricity is affected by economic activity, weather and weather-related events, and demand side management and energy efficiency measures. Finally, DPL has refinancing risk related to 2013 debt maturities of \$470 million and \$300 million of un-drawn credit facilities at DP&L.

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

### ***U.S. Generation***

***Business Description.*** In the U.S., we own a diversified generation portfolio in terms of geography, technology and fuel source. The principal markets where we are engaged in the generation and supply of electricity (energy and capacity) are the Western Electricity Coordinating Council (WECC), PJM, Southwest Power Pool Electric Energy Network (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 7% of the state's installed capacity and 16% 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 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 95% 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 often captures 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.

#### ***Regulatory Framework***

***Environmental Matters.*** The California State Water Resources Control Board (SWRCB) policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (the Policy) became effective on October 1, 2010 and provides a phased compliance schedule, which requires all AES Southland plants to be compliant by December 31, 2020. The Policy establishes technology-based standards to implement the U.S. Clean Water Act 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 Best Technology Available (BTA) for cooling water intake structures. There are two potential tracks to comply with the Policy:

Track 1 Reduce intake flow rate on each unit to a level commensurate with that which can be obtained by a closed-cycle wet cooling system.

Track 2 If they are able to demonstrate that Track 1 is not feasible, the existing power plant must reduce impingement mortality and entrainment of marine life, on a unit-by-unit basis, to a comparable level to that which would be achieved under Track 1, using operational or structural controls, or both.

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As required by the Policy, AES Southland submitted its implementation plans by April 1, 2011 and proposed to comply with the Policy by retiring the existing units and replacing them with new units that would not use ocean water provided satisfactory contracts could be obtained to support development and construction of new units. The SWRCB is currently reviewing the implementation plans and has requested additional information to assist with their evaluation. For further discussion of environmental laws and regulations affecting the U.S. businesses, see Environmental and Land Use Regulations later in this section.

### *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 usually met or exceeded its contractual availability.

### *Additional U.S. Generation Businesses*

*Business Description.* Additional businesses include thermal and wind generating facilities, of which AES Hawaii and AES Warrior Run are the most significant, and our energy storage line of business.

Many of our U.S. generation plants provide baseload operations and are required to maintain a guaranteed level of availability. Any change in availability has a direct impact on financial performance. The plants are generally eligible for availability bonuses on an annual basis if they meet certain requirements. In addition to plant availability, fuel cost is a key business driver for some of our facilities. AES Hawaii receives a fuel payment from its offtaker, which is based on a fixed rate indexed to the Gross National Product Implicit Price Deflator (GNIPD). 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 2013; the business could be subject to variability in coal pricing beginning in 2014. To mitigate fuel risk beyond 2013, 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.

AES Warrior Run has a fuel contract with a major global fuel supplier where the prices for fuel and ash removal are indexed to its PPA. This fuel contract expires in 2020 prior to the expiration of the PPA in 2030, resulting in fuel price risk for the remaining 10 years of the PPA. AES Warrior Run has begun efforts to source fuel longer term, and facilitate fuel flexibility.

*Market Structure.* Two of the primary fuels used by our U.S. generation facilities, coal and pet coke, are commodities with international prices set by market factors, although the price of the third 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 U.S. with PPAs have mechanisms to recover fuel costs from the offtaker, including an energy payment that is partially based on the market price of coal. In addition, these businesses often have an opportunity to increase or decrease profitability from payments under their PPAs depending on such items as plant efficiency and availability, heat rate, ability to buy coal at lower costs through AES' global sourcing program, and fuel flexibility. Revenue may change materially as prices in fuel markets fluctuate, but the variable margin or profitability should not be materially changed when market price fluctuations in fuel are borne by the offtaker.

*Regulatory Framework.* Several of our generation businesses in the United States, currently operate as Qualifying Facilities (QFs) as defined under Public Utility Regulatory Policies Act (PURPA). These businesses entered into long-term contracts with electric utilities that had a mandatory obligation at that time, as specified under PURPA, to purchase power from QFs at the utility's avoided cost (i.e., the likely costs for both

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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 must 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 Exempt Wholesale Generators ( EWG ) as defined under EPC Act 1992. These businesses, subject to approval of the Federal Energy Regulatory Commission ( FERC ), have the right to sell power at market-based rates, either directly to the wholesale market or to a third-party off taker such as a power marketer or utility/industrial customer. Under the Federal Power Act ( FPA ) and FERC's regulations, approval from FERC to sell wholesale power at market-based rates is generally dependent upon a showing to FERC that the seller lacks market power in generation and transmission, that the seller and its affiliates cannot erect other barriers to market entry and that there is no opportunity for abusive transactions involving regulated affiliates of the seller. To prevent market manipulation, FERC requires sellers with market-based rate authority to file certain reports, including a triennial updated market power analysis for markets in which they control certain threshold amounts of generation.

*Other Regulatory Matters*

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

Our businesses are subject to emission regulations, which may result in increased operating costs or the purchase of additional pollution control equipment if emission levels are exceeded. Our businesses periodically review their obligations for compliance with environmental laws, including site restoration and remediation. Because of the uncertainties associated with environmental assessment and remediation activities, future costs of compliance or remediation could be higher or lower than the amount currently accrued, if any. For a discussion of environmental laws and regulations affecting the U.S. business, see *Other United States Environmental and Land Use Legislation and Regulations* later in this section. In April 2012, the EPA's rule to establish maximum achievable control technology standards for each hazardous air pollutant regulated under the Clean Air Act ( CAA ) emitted from coal and oil-fired electric utilities, known as MATS became effective.

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### ***Andes SBU***

Our Andes SBU has generation facilities in three countries, Chile, Colombia and Argentina. Our Andes operations accounted for 16%, 18% and 14% of consolidated AES gross margin and 18%, 28% and 21% of consolidated AES adjusted PTC (a non-GAAP measure) in 2012, 2011 and 2010, respectively. 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. 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	Argentina, Chile and Colombia
Generation Capacity	7,740 gross MW (5,952 proportional MW)
Generation Facilities	33 (including 3 under construction)
Key Generation Businesses	AES Gener, Chivor and AES Argentina

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Operating installed capacity of our Andes SBU totals 7,740 MW, of which 46%, 41% and 13% 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 (Percent, Rounded)	Year Acquired or Began Operation
Chivor	Colombia	Hydro	1,000	71%	2000
<i>Colombia Subtotal</i>			<i>1,000</i>		
Gener <sup>(1)</sup>	Chile	Hydro/Coal/Diesel/Biomass	986	71%	2000
Guacolda <sup>(2)</sup>	Chile	Coal/Pet Coke	608	35%	2000
Electrica Angamos	Chile	Coal	545	71%	2011
Electrica Santiago <sup>(3)</sup>	Chile	Gas/Diesel	479	71%	2000
Norgener	Chile	Coal/Pet Coke	277	71%	2000
Electrica Ventanas <sup>(4)</sup>	Chile	Coal	272	71%	2010
<i>Chile Subtotal</i>			<i>3,167</i>		
TermoAndes <sup>(5)</sup>	Argentina	Gas/Diesel	643	71%	2000
<i>AES Gener Subtotal</i>			<i>4,810</i>		
Alicura	Argentina	Hydro	1,050	100%	2000
Paraná-GT	Argentina	Gas/Oil/Biodiesel	845	100%	2001
San Nicolás	Argentina	Coal/Oil/Gas	675	100%	1993
Los Caracoles <sup>(6)</sup>	Argentina	Hydro	125	0%	2009
Cabra Corral	Argentina	Hydro	102	100%	1995
Quebrada de Ullum <sup>(6)</sup>	Argentina	Hydro	45	0%	2004
Ullum	Argentina	Hydro	45	100%	1996
Sarmiento	Argentina	Gas/Diesel	33	100%	1996
El Tunal	Argentina	Hydro	10	100%	1995
<i>Argentina Subtotal</i>			<i>2,930</i>		
<b>Andes Total</b>			<b>7,740</b>		

(1) Gener plants: Alfalfal, Laguna Verde, Laguna Verde Turbogas, Laja, Los Vientos, Maitenas, Queltehues, San Francisco de Mostazal, Santa Lidia, Ventanas and Volcán.

(2) 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.

(3) Electrica Santiago plants: Nueva Renca and Renca.

(4) Electrica Ventanas plant: Nueva Ventanas.

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

(6) AES operates these facilities through management or O&M agreements and owns no equity interest in these businesses.

*Under construction*

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Expected Year of Commercial Operations
Gener Ventanas IV (Campiché <sup>(4)</sup> )	Chile	Coal	270	71%	2013
Gener Guacolda V	Chile	Coal	152	36%	2015
<i>Chile Subtotal</i>			<i>422</i>		
Chivor Tunjita	Colombia	Hydro	20	71%	2014
<i>Colombia Subtotal</i>			<i>20</i>		

Andes Total

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<sup>(1)</sup> Gener Ventanas IV (Campiche): Currently in commissioning.  
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 Central Interconnected Electricity System ( SIC ) and Northern Interconnected Electricity System ( SING ). As of December 31, 2012, AES Gener's net power production in the SIC totaled 11,590 GWh (24% of the SIC's total generation) and AES Gener's net power production in the SING totaled 4,989 GWh (33% of the SING's total generation). In terms of aggregate installed capacity, AES Gener is the second largest generation operator in Chile with an installed capacity of 3,810 MW and market share of 21% as of December 31, 2012. In the SIC, AES Gener has installed capacity of 2,345 MW representing 17% of gross installed capacity in the system. In the SING, AES Gener have installed capacity of 1,465 MW representing 32% of gross installed capacity in the system. AES Gener's installed capacity in the SING includes the TermoAndes plant, which is located in northwest Argentina and connected to both the SING by a transmission line owned by AES Gener, and the Argentine electricity grid. TermoAndes was originally constructed to supply the SING by exporting energy from 2000 to 2011. TermoAndes' electricity export permit expired on January 31, 2013. While AES Gener continues to evaluate potential renewal, TermoAndes is currently selling output of this plant in Argentina.

AES Gener owns a diversified generation portfolio 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, extending from Antofagasta in the north to Concepción in south-central Chile. 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 back-up



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short-term 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 1,400 MW and increasing AES Gener's installed capacity by 49% from 2006 to 2013. Additionally, they are in the process of commissioning a 270 MW coal-fired plant (Ventanas IV) and constructing an additional 152 MW coal-fired plant (Guacolda V). AES Gener plans to continue to grow with the construction of new projects in both the SIC and the SING, taking advantage of AES Gener's presence and knowledge of the market, in addition to AES Gener's project management and construction skills. AES Gener's key short-term development projects include the 532 MW coal-fired Cochrane power plant in the SING and the 531 MW run-of-river hydroelectric Alto Maipo power 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, which includes both regulated and unregulated customers. AES Gener reserves their higher variable cost units as designated back-up facilities, principally the diesel and gas-fired units in Chile, for sales to the short-term market during scarce system supply conditions, such as dry hydrological conditions and plant outages. In Chile, sales on the short-term market are made only to other generation companies that are members of the relevant Economic Load Dispatch Center (CDEC) at the system marginal cost.

AES Gener currently has long-term contracts, with average terms between 10 and 18 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, which 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 full 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 the water inflows in the case of hydroelectric plants. The capacity price is fixed by the National Energy Commission (CNE) in the semi-annual 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 13,633 MW as of December 31, 2012. The SIC serves approximately 92% of the Chilean population, including the densely populated Santiago Metropolitan Region, and supplies 75% of the country's electricity demand. The SING serves about 6% of the Chilean population, supplying 24% of Chile's electricity consumption, and is mostly oriented toward mining companies.

In 2012, thermoelectric generation represented 69% of the total generation in Chile. In the SIC, thermoelectric generation represents 55% of installed capacity and is required to fulfill demand not satisfied by hydroelectric output, and is critical to guaranteeing reliable and dependable electricity supply under dry hydrological conditions. In the SING, which includes the Atacama Desert, the driest desert in the world, thermoelectric capacity represents 99.7% of installed capacity. The fuels used for generation, mainly coal, diesel and LNG, are commodities with 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, short-term 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 occurs 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 2012, hydroelectric generation represented 41% of total energy production.

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### *Regulatory Framework*

*Electricity Regulation.* The governmental entity which 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 which 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. Under 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 also engage in contracted sales among themselves at negotiated prices, outside the short-term market. Electricity prices in Chile, under contract and on the short-term 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 particulate matter 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 particulate matter emission will go into effect by the end of 2013 and the new limits for SO<sub>2</sub> (sulfur dioxide), NO<sub>x</sub> (nitrogen dioxide) 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 in Chile will invest approximately \$280 million, at its older coal facilities, including its proportional investment in an equity-method investee, Guacolda. In 2012, AES Gener initiated these investments, spending approximately \$42 million, and the remaining \$238 million will be invested between 2013 and 2015 in order to comply within the required timeframe.

Chilean law requires every electricity generator to supply a certain portion of their total contractual obligations with non-conventional renewable energies ( NCREs ). The required amount is determined based on contract agreements executed after August 31, 2007. The NCRE requirement is equal to 5.0% for the period from 2010 through 2014 and thereafter the required percentage increases by 0.5% each year, to a maximum of 10.0% by 2024. Generation companies are able to meet this requirement by developing their own NCRE generation capacity (wind, solar, biomass, geothermal and small hydroelectric technology), or purchasing NCRE 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. They have 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 NCRE requirements. The authorities have announced a potential increase in future NCRE requirements and a proposed bill is being discussed in Congress.

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### *Key Financial Drivers*

In Chile, AES Gener's contracting strategy, determining both the amount of capacity to contract or leave uncommitted for spot market sales and the relevant pricing formulas including indexation, is important to our profitability. AES Gener aligns their contracts with their efficient generation capacity, contracting a significant portion of their efficient capacity under long-term contracts, while reserving their higher variable cost units for sales on the spot market. The performance of their generating assets, efficiency and availability, is also a critical part of their strategy in order to maximize contracted margins and avoid exposure to spot price volatility.

In the SIC, hydrological conditions are also important financial drivers since they largely influence plant dispatch and therefore, spot market prices. AES Gener becomes a short-term purchaser of electricity from other generation companies during rainy hydrological conditions, when short-term market prices are at their lowest, and AES Gener's spot sales of electricity generated by their back-up facilities increase in periods of low water conditions, when short-term market prices are at their highest. Both extreme hydrological conditions provide AES Gener with improved earnings and cash flow.

Successful execution and commencement of operation of AES Gener's growth projects under construction, currently Ventanas IV (Campiche) and Guacolda V is important to their financial performance. In accordance with AES Gener's commercial contract strategy, in order to reduce their exposure to the potential imbalance between supply and demand and ensure investment recovery, their policy is to contract a significant proportion of the new efficient project capacity under long-term energy supply contracts.

### *Colombia*

*Business Description.* As of December 31, 2012, AES Gener's net power production in Colombia was 4,664 GWh (8% of the country's total generation). The Chivor plant, a subsidiary of AES Gener, is a hydroelectric facility with installed capacity of 1,000 MW, located approximately 160 km east of Bogota. The installed capacity represents approximately 7% of system capacity as of December 31, 2012. The plant consists of eight 125 MW dam-based hydroelectric generating units in two separate sub-facilities. Because all of Chivor's installed capacity in Colombia is hydroelectric, they are dependent on the prevailing hydrological conditions in the region in which they operate. Hydrological conditions largely influence generation and the short-term prices at which they sell Chivor's 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 short-term market to other generation and trading companies at the system marginal cost, allowing us to maximize the operating margin during optimal price conditions.

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 National Interconnected System (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 14,533 MW as of December 31, 2012, composed of 67% hydroelectric generation, 31% thermoelectric generation and 2% 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 2012, 80% of total energy demand was supplied by hydroelectric plants with the remaining supply from thermoelectric generation (19%) and cogeneration and self-generation power (1%). From 2002 to 2012,

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electricity demand in the SIN has grown at a compound annual growth rate of 2.9% and the Mining and Energetic Planning Unit ( UPME ) projects an average annual compounded growth rate in electricity demand of 4% per year for the next ten years.

### *Regulatory Framework*

*Electricity Regulation.* Since 1994, the electricity sector in Colombia has operated as 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 Energy and Gas Regulation Commission ( CREG ). Other government entities which 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. 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. Additionally, a proposal has been discussed which would allow authorities to dictate emergency energy situations, in cases such as severe drought conditions, in order to implement measures to prevent shortages and other negative economic impacts.

### *Key Financial Drivers*

Hydrological conditions largely influence Chivor's generation level. Maintaining the appropriate contract level, while working to maximize revenue, through sale of excess generation, is key to Chivor's results of operations.

### ***Argentina***

*Our Business.* As of December 31, 2012, AES Argentina's net power production in the Argentine Interconnected System ( SADI ) totaled 14,426 GWh, representing 11% of the SADI's total generation. AES Argentina operates 3,573 MW which represents 11% of country's total installed capacity, making us the third-largest generator. The installed capacity in the SADI includes the TermoAndes plant, a subsidiary of AES Gener, which is connected both to the SADI and the Chilean SING. AES Argentina has a diversified generation portfolio of ten generation facilities, comprised of 62% thermoelectric and 38% hydroelectric capacity. All of the thermoelectric capacity has the capability to burn alternative fuels. Approximately 69% of the thermoelectric capacity can operate alternatively with natural gas or diesel oil and the remaining 31% can operate alternatively with natural gas or fuel oil.

AES Argentina sells its production to customers on the short-term market, where prices are largely regulated. In 2012, approximately 80% of the energy was sold on the short-term market and 20% was under contract. Short-term prices are determined in Argentine pesos by the Wholesale Electric Market Administrator ( CAMMESA ) and have been frozen at approximately \$120 pesos per MWh for the past three years.

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All of the thermoelectric facilities have the ability to use natural gas and receive gas supplied through contracts with Argentine producers. In recent years, gas supply restrictions in Argentina, particularly during the southern cone's winter season, have affected some of the plants, specifically 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 of 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 potential renewal is being evaluated.

*Market Structure.* The SADI electricity market is managed by CAMMESA. As of December 31, 2012, the installed capacity of the SADI totaled 31,139 MW. In 2012, 66% of total energy demand was supplied by thermoelectric plants, 29% by hydroelectric plants and 5% from nuclear, wind and solar plants.

Thermoelectric generation in the SADI is principally fueled by natural gas. However, since 2004, and 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 that the cost of these fuels is generally higher than natural gas, the extra cost or "dispatch surcharge", is currently reimbursed by CAMMESA, by including the surcharge in the energy margin paid to generators in order to compensate them for the cost of fuel. CAMMESA publishes reference prices on a biweekly basis for each type of fuel, capping the maximum price to be paid by generators.

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. The wholesale electric market is administrated by CAMMESA, which 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 cancelation 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 development. AES Argentina will receive a pro rata ownership interest in these newly-built plants once the accounts receivables have been paid. The Argentine government has continued to intervene in the energy sector and AES Argentina believes that additional modifications to Argentine electricity sector regulations are likely. In August 2012, authorities advised of a proposal to modify the current energy regulatory framework, moving from a "marginal cost market" to a "cost-plus market", although AES Argentina is not aware of the details or timing for this modification at present. See Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations* for additional details.

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### Key Financial Drivers

Potential changes in regulations, especially changes related to a revenue requirement pricing scheme or a change to the coal rule, which establishes the margin for AES Argentina's San Nicolas plant, are key drivers for the Argentina business. The ability to contract sales with unregulated customers at TermoAndes and obtain the natural gas required to supply the contracts is another area of focus for the business. Macroeconomic conditions, further regulatory changes, and AES Argentina's ability to collect on receivables, including FONINVEMEM and future receivables, impact operating performance and cash flow. Finally, hydrological conditions largely determine our plants' dispatch.

### Brazil SBU

Our Brazil SBU has generation and distribution facilities. Our Brazil operations accounted for 26%, 45% and 45% of consolidated AES gross margin and 15%, 23% and 25% of consolidated AES adjusted PTC (a non-GAAP measure) in 2012, 2011 and 2010, respectively. 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.

The following table provides highlights of our Brazil operations:

Generation Capacity	3,298 gross MW (932 proportional MW)
Utilities Penetration	7.7 million customers (54,408 GWh)
Generation Facilities	13
Utilities Businesses	2
Key Generation Businesses	Tietê and Uruguaiana
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. Tietê represents approximately 11%, as of December 2012, of the total generation capacity in the State of São Paulo and is the second largest private generator in Brazil. We also have another generation plant, AES Uruguaiana, located in the South of Brazil with a 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 (Percent, Rounded)	Year Acquired or Began Operation
Tietê <sup>(1)</sup>	Brazil	Hydro	2,658	24%	1999
Uruguaiana	Brazil	Gas	640	46%	2000
Brazil Total			3,298		

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- <sup>(1)</sup> 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), São Joaquim (3 MW) and São José (4 MW).

*Distribution.* AES owns interests in two distribution facilities in Brazil. 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<sup>2</sup>, covering a region of high demographic density and the largest concentration of GDP in the country. It is the largest power distributor in Latin America serving approximately 16.6 million people and 6.5 million consumer units.

AES Sul is responsible for supplying electricity to 118 municipalities of the metropolitan region of Porto Alegre to the border with Uruguay and Argentina in a total area of 99,512 km<sup>2</sup>, serving approximately 3.3 million people and 1.24 million consumer units.

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

<b>Business</b>	<b>Location</b>	<b>Approximate Number of Customers Served as of 12/31/2012</b>	<b>GWh Sold in 2012</b>	<b>AES Equity Interest (Percent, Rounded)</b>	<b>Year Acquired</b>
Eletropaulo	Brazil	6,483,000	45,557	16%	1998
Sul	Brazil	1,240,000	8,851	100%	1997
		7,723,000	54,408		

The following map illustrates the location of our Brazil facilities:

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### ***Brazil Businesses***

#### ***Business Description***

*Generation.* Tietê is 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, our partner the Brazilian Development Bank ( 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 100% of its assured capacity to Eletropaulo under a long-term PPA, which is expiring in December 2015. After that, Tietê's strategy is to contract 95% of this energy and the remaining portion is to be sold in the short-term market. The contract is price-adjusted annually for inflation (IGP-M). Current regulated auctions for similar energy are clearing at prices that are below our existing contract prices.

Under the concession agreement, Tietê had an obligation to increase its capacity by 15% by 2007, with no penalty imposed for lack of compliance, although there is a legal case initiated by the state of São Paulo requiring the investment to be performed. Tietê, as well as other concessionaire generators, was not able to meet this requirement due to regulatory, environmental, hydrological and fuel constraints. Tietê is in the process of analyzing options to meet the obligation.

Uruguaiana is a 640 MW gas-fired combined cycle power plant commissioned in December 2000. AES manages and owns a 46% economic interest and the remaining is held by BNDES. The facility is located in the town of Uruguaiana in the state of Rio Grande do Sul. The plant's operations were suspended in April 2009 due to unavailability of gas. However the facility resumed operations on February 8, 2013 and expects to continue for 60 days due to a recently secured short-term supply of LNG for the facility. At the first stage, the thermal plant will operate with capacity of approximately 164 MW. Uruguaiana is working to secure gas on a long-term basis, to operate at the plant's full capacity.

*Distribution.* Eletropaulo distributes electricity to 24 municipalities that compose the Greater São Paulo, including the capital of São Paulo State, Brazil's main economic and financial center. The Company is the largest electric power distributor in Latin America in terms of both revenues and volume of energy distribution.

AES owns 16% of the economic interest of 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.

Sul distributes electricity in 118 municipalities 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 owns 100% of the economic interest and manages this business under a 30-year concession expiring in 2027.

#### ***Market Structure***

Tietê is one of many generators in the 117,000 MW installed capacity system comprising approximately 75% of the market with regulated customers and the remainder with free customers. Of this total system installed capacity, 78% is hydroelectric, 16% is thermoelectric and 6% is from renewable sources (biomass and wind).

#### ***Regulatory Framework***

The Brazilian power sector has a number of different regulatory bodies, the most relevant of which are: (i) the Minister of Mines and Energy ( MME ), which is the government's main energy policy maker; (ii) the Energy Planning Enterprise ( EPE ), which is the government's agency for the long-term planning of the



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country's generation and transmission systems expansion to ensure high reliability of supply at the lowest possible cost; (iii) ANEEL, which is the agency that runs the day-to-day execution of the government's policies, including tariff adjustments and periodic tariff resets for distribution; and (iv) the National System Operator (ONS), which is responsible for coordinating and controlling the operation of the national grid.

The Government of Brazil recently announced an Energy Cost Reduction Program, which targets a 20 percent reduction in electricity prices. About one-third of this planned reduction is expected to be driven by lowering sector charges (indirect taxes). The remaining two-thirds of this reduction is being targeted through re-negotiations of new conditions with various generators and transmission and distribution companies, whose concession contracts are up for renewal between 2015 and 2017. The Government of Brazil issued Provision Measure 579 (MP 579) and other related rules. MP 579 is still pending Congressional approval and implementation of the Energy Cost Reduction Program is scheduled to be completed in the first quarter. The concession at Tietê, our generation business in Brazil, was granted after 1995 and expires in 2029 and thus is not subject to this regulation. Furthermore, we are insulated in the short-term, as 100% of Tietê's output is contracted with Eletropaulo through December 2015. Beyond 2015, any developments will be a function of the supply-demand and new investment dynamics in Brazil. Both Eletropaulo and Sul, have concessions granted after 1995 and valid until 2028 and 2027, respectively, and thus are not affected by the proposed MP 579. On January 24, 2013, an extraordinary tariff reduction for all distribution companies was announced with an average reduction at Eletropaulo of 20% and at Sul of 25%. Since the distribution businesses earn a return on the regulated asset base and energy purchases are treated as a pass-through cost, management expects these changes will have a neutral impact on our gross margin.

*Electricity Regulation.* In Brazil, MME determines the maximum amount of energy that a plant can sell – assured energy –, which represents the long-term average expected energy production of the plant. Under the current rules, the plant's assured energy can be sold to the distribution companies through long-term (regulated) auctions or under unregulated bilateral contracts with large consumers or energy trading companies.

Under the power sector model, a distribution company is obligated to contract 100% of the anticipated energy needs through the regulated auction market. The regulated utilities can pass through the amounts contracted up to 103% of their load. If the company is contracted below 99% of its projected load, there is no pass-through mechanism for the energy purchased below that limit.

ANEEL sets the tariff for each distribution company, which is based on Return on Asset Base methodology that also benchmarks operational costs against other distribution companies.

The tariff charged to regulated customers consists of two elements: (i) full pass through of non-manageable costs (Parcel A), which includes energy purchase costs, sector charges and transmission and distribution system expenses; and (ii) a manageable cost component (Parcel B), which includes operation and maintenance costs (defined by ANEEL), recovery of assets and a component for the value added by the distributor (calculated as the net asset base multiplied by the regulatory pre-tax weighted average cost of capital).

For distribution companies, a tariff reset occurs every four to five years, depending on the specific business. Eletropaulo's tariff reset occurs every four years and the next tariff reset will be in July 2015. Sul's tariff resets every five years and the current rate will be set for another five years in April 2013.

In addition to tariff reset, Parcel A is reviewed and adjusted once a year. Parcel B is adjusted once every year reflecting inflation offset by X-Factor to capture windfall gains from volume sales growth.

Distribution companies could also be entitled to extraordinary tariff revisions, subject to ANEEL approval, in the event of significant and proven loss of the economic and financial equilibrium.

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Eletropaulo has ongoing discussions with the regulator in the administrative level regarding the parameters of the tariff reset applied in July 2012, retroactive to July 2011. The main discussions involve the shielded regulatory asset base and whether adjustments should be made to it, the amount of investments made by the company that were not included in the tariff and the benchmark used for regulatory losses .

During 2012, Eletropaulo received two infraction notices from ANEEL, relating to the financial audit of its fixed assets. The notices allege non-conformities in the regulatory accounting applied by Eletropaulo to the fixed assets and non-conformities in the regulatory asset base, both of which impact the regulatory asset base used to calculate the tariff charged to customers. Management has filed appeals contesting the alleged non-conformities and fines imposed, and are awaiting responses. Management has recognized its best estimate of the probable loss as of December 31, 2012. There can be no assurances that additional losses may be necessary which could have a material impact on our results of operations.

For Sul, the tariff reset for the next five years, will occur in April 2013. ANEEL opened a public hearing on February 5, 2013, which is expected to run until March 8, 2013 to discuss the rates. Although we believe Sul should receive a fair and reasonable tariff, there can be no assurances made around the outcome of the process. In the event that the tariff reset is below our expectations, there could be a material impact on our results of operations.

### *Key Financial Drivers*

As the system is highly dependent on hydroelectric generation, Brazil SBU generation companies are affected by the hydrology in the overall sector, as well as availability of Tietê's plants and reliability of the Uruguaiana facility. The availability of gas for continued operations is a driver for Uruguaiana.

For Brazil SBU distribution companies, the demand for electricity is affected by economic activity, weather patterns and customers' consumption behavior. Further, AES Sul is focused on working with stakeholders to determine a fair and reasonable outcome for the tariff reset scheduled to be implemented in April 2013. Finally, the distribution companies' operating performance is driven by the quality of service and ability to control non-technical losses.

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Our MCAC SBU has a portfolio of distribution businesses and generation facilities, including renewable energy, in six countries, with a total capacity of 3,860 MW and distribution networks serving more than 1.2 million customers as of December 31, 2012. MCAC operations accounted for 15%, 13% and 12% of consolidated AES gross margin and 18%, 17% and 17% of consolidated AES adjusted PTC (a non-GAAP measure) in 2012, 2011 and 2010, respectively. 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.

The following table provides highlights of our MCAC SBU operations:

Countries	Dominican Republic, El Salvador, Mexico, Panama , Puerto Rico and Trinidad
Generation Capacity	3,860 gross MW (2,585 proportional MW)
Utilities Penetration	1.2 million customers (3,642 GWh)
Generation Facilities	16
Utilities Businesses	4
Key Generation Businesses	Andres, Panama and TEG TEP
Key Distribution Businesses	El Salvador

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The total operating installed capacity of our MCAC SBU is distributed 27%, 22%, 18% and 14% in Mexico, Dominican Republic, Panama and Puerto Rico, respectively. The table below lists our MCAC SBU facilities:

<b>Business</b>	<b>Location</b>	<b>Fuel</b>	<b>Gross MW</b>	<b>AES Equity Interest (Percent, Rounded)</b>	<b>Year Acquired or Began Operation</b>
Andres	Dominican Republic	Gas	319	100%	2003
Itabo <sup>(1)</sup>	Dominican Republic	Coal/Gas			