AES CORP
Form 10-K
February 26, 2010
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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, 2009

-OR-

¨ **TRANSITION REPORT FILED PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

COMMISSION FILE NUMBER 1-12291

The AES Corporation

(Exact name of registrant as specified in its charter)

Delaware	**54 1163725**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**
4300 Wilson Boulevard Arlington, Virginia	**22203**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (703) 522-1315

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Stock, par value $0.01 per share	**New York Stock Exchange**
AES Trust III, $3.375 Trust Convertible Preferred Securities	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

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 x

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates on June 30, 2009, the last business day of the Registrant s most recently completed second fiscal quarter (based on the closing sale price of $11.61 of the Registrant s Common Stock, as reported by the New York Stock Exchange on such date) was approximately $7.853 billion.

The number of shares outstanding of the Registrant s Common Stock, par value $0.01 per share, on February 19, 2010, was 668,469,159.

DOCUMENTS INCORPORATED BY REFERENCE

(a) Portions of the 2009 Proxy Statement are incorporated by reference in Parts II and III

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THE AES CORPORATION

FISCAL YEAR 2009 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, collectivel The term The AES Corporation 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 has recently been in decline and faces considerable uncertainty for the foreseeable future which further increases many of the risks discussed in this Form 10-K;
- our ability to achieve expected rate increases in our Utility businesses;
- our ability to manage our operation and maintenance costs;
- the performance and reliability of our generating plants, including our ability to reduce unscheduled down-times;
- 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 our ability to hedge our exposure to such market price risk;
- changes in the prices and availability of coal, gas and other fuels and 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 those affecting the availability and cost of capital in order to refinance existing debt and finance capital expenditures, acquisitions, investments and other corporate purposes;
- changes in 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;
- changes in inflation, interest rates and foreign currency exchange rates;
- our ability to purchase and sell assets at attractive prices and on other attractive terms;

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;

the expropriation or nationalization of our businesses or assets by foreign governments, whether with or without adequate compensation;

changes in laws, rules and regulations affecting our 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 (RTO) that includes our utility service territory, the application of market power criteria by the Federal Energy Regulatory Commission (FERC), changes in law

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resulting from new federal energy legislation, including the effects of the repeal of Public Utility Holding Company Act of 1935 (PUHCA 1935), 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 (GHG) reductions and energy storage including tax incentives;

changes in environmental laws, including requirements for reduced emissions of sulfur, nitrogen, carbon, mercury, and other substances, including potential GHG legislation, regulation and/or treaties;

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 wind businesses, which rely, in part, on actual wind conditions and wind turbine performance being in line with our expectations;

the success of our initiatives in other renewable energy projects, as well as greenhouse gas emissions reduction projects (GHG Emissions Reductions Projects) and energy storage projects, and the attractiveness of market prices for carbon offsets under markets governed by the Kyoto Protocol of the United Nations Framework Convention on Climate Change (the Kyoto Protocol), and consistent and orderly regulatory procedures governing the application, regulation, issuance of Certified Emission Reduction (CER) credits and the extension of such regulations beyond 2012;

our ability to keep up with advances in technology;

the potential effects of threatened or actual acts of terrorism and war;

changes in tax laws and the effects of our strategies to reduce tax payments;

the effects of litigation and government investigations;

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;

changes in accounting standards, corporate governance and securities law requirements;

our ability to maintain effective internal controls over financial reporting; and

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 (GAAP).

These factors in addition to others described elsewhere in this Form 10-K 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.

Except to the extent required by the federal securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

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ITEM 1.   BUSINESS

Overview

We are a global power company. We own a portfolio of electricity generation and distribution businesses on five continents in 29 countries, with total capacity of approximately 40,300 Megawatts (MW) and distribution networks serving over 11 million people as of December 31, 2009. In addition, we have more than 2,200 MW under construction in six countries. Our global workforce of 27,000 people provides electricity to people in diverse markets ranging from urban centers in the United States to remote villages in India. We were incorporated in Delaware in 1981 and for almost three decades we have been committed to providing safe and reliable energy.

We own and operate two primary types of businesses. The first is our Generation business, where we own and/or operate power plants to generate and sell power to wholesale customers such as utilities and other intermediaries. The second is our Utilities business, where we own and/or operate utilities to distribute, transmit and sell electricity to end-user customers in the residential, commercial, industrial and governmental sectors within a defined service area.

Our assets are diverse with respect to fuel source and type of market, which helps reduce certain types of operating risk. Our portfolio employs a broad range of fuels, including coal, gas, fuel oil, biomass and renewable sources such as hydroelectric power, wind and solar, which reduces the risks associated with dependence on any one fuel source. Our presence in mature markets helps reduce the volatility associated with our businesses in faster-growing emerging markets. In addition, our Generation portfolio is largely contracted, which reduces the risk related to market prices of electricity and fuel. We also attempt to limit risk by hedging much of our interest rate and commodity risk, and by matching the currency of most of our subsidiary debt to the revenue of the underlying business. However, our business is still subject to these and other risks, which are further disclosed in Item 1A. Risk Factors of this Form 10-K.

Our goal is to maximize value for our shareholders through continued focus on increasing the profitability of our existing portfolio and increasing free cash flow while managing our risk and employing rigorous capital allocation. We will continue to seek prudent expansion of our traditional Generation and Utilities lines of business, along with expansion of wind, solar and energy storage, through acquisitions or greenfield developments. Portfolio management remains an area of focus through which we have sold and will continue to sell or monetize a portion of certain businesses or assets when market values appear attractive. Furthermore, we will continue to focus on improving our business operations and management processes, including our internal controls over financial reporting.

Key Lines of Business

AES primary sources of revenue and gross margin today are from Generation and Utilities. These businesses are distinguished by the nature of the customers, operational differences, cost structure, regulatory environment and risk exposure. The breakout of revenue and gross margin between Generation and Utilities for the years ended December 31, 2009, 2008 and 2007, respectively is shown below. Operating results for integrated utilities, which have both Utilities and Generation, are reflected in the Utilities amounts below.

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Revenue

($ in billions)

Gross Margin

($ in billions)

(1) Utilities gross margin includes the margin from generation businesses owned by the Company and from whom the utility purchases energy.

Generation

We currently own or operate a portfolio of approximately 34,000 MW, excluding the generation capabilities of our integrated utilities, consisting of 99 Generation facilities in 26 countries on five continents at our generation businesses. We also have approximately 1,900 MW of capacity currently under construction in four countries. We are a major power source in many countries, such as Panama where we are the largest generator of electricity, and Chile, where AES Gener (Gener) is the second largest electricity generation company in terms of capacity. Our Generation business uses a wide range of technologies and fuel types including coal, combined-cycle gas turbines, hydroelectric power and biomass. Generation revenue was $6.3 billion, $7.6 billion and $6.2 billion for the years ended December 31, 2009, 2008 and 2007, respectively.

Performance drivers for our Generation businesses include, among other factors, plant reliability, fuel costs, power prices, volume and fixed-cost management. Growth in the Generation business is largely tied to securing new power purchase agreements (PPAs), expanding capacity in our existing facilities and building or acquiring new power plants.

The majority of the electricity produced by our Generation businesses is sold under long-term contracts, or PPAs, to wholesale customers. In 2009, approximately 65% of the revenue from our Generation business was from plants that operate under PPAs of three years or longer for 75% or more of their output capacity. These businesses often reduce their exposure to fuel supply risks by entering into long-term fuel supply contracts or fuel tolling arrangements where the customer assumes full responsibility for purchasing and supplying the fuel to the power plant. These long-term contractual agreements result in relatively predictable cash flows and earnings and reduce exposure to volatility in the market price for electricity and fuel; however, the amount of earnings and cash flow predictability varies from business to business based on the degree to which its exposure is limited by the contracts it has negotiated.

Our Generation businesses with long-term contracts face most of their competition from other utilities and independent power producers (IPPs) prior to the execution of a power sales agreement during the development phase of a project or upon expiration of an existing agreement. Once a project is operational, we traditionally have faced limited competition due to the long-term nature of the generation contracts. However, as our existing contracts expire, the introduction of new power markets has increased competition to attract new customers and maintain our current customer base.

The balance of our Generation business sells power through competitive markets under short-term contracts, directly in the spot market or, in some cases, at regulated prices. As a result, the cash flows and earnings associated with these businesses are more sensitive to fluctuations in the market price for electricity, natural gas, coal and other fuels. However, for a number of these facilities, including our plants in New York, which include a fleet of coal-fired plants, we have hedged a portion of our exposure to fuel, energy and emissions pricing for 2010. Competitive factors for these facilities include price, reliability, operational cost and third party credit requirements.

Utilities

AES utility businesses distribute power to over 11 million people in seven countries on five continents and consist primarily of 14 companies owned or operated under management agreements, each of which operate in defined service areas. These businesses also include 15 generation plants in two countries with generation capacity totaling approximately 4,600 MW. These businesses have a variety of structures ranging from pure distribution businesses to fully integrated utilities, which generate, transmit and distribute power. Indianapolis Power & Light (IPL) has the exclusive right to provide retail services to approximately 470,000 customers in Indianapolis, Indiana. Eletropaulo Metropolitana Electricidad de São Paulo S.A (AES Eletropaulo or Eletropaulo), serving the São Paulo metropolitan region for over 100 years, has approximately six million customers and is the largest electricity distribution company in Brazil in terms of revenue and electricity distributed. In Cameroon, we are the primary generator and distributor of electricity and in El Salvador we provide distribution services to serve more than 76% of the country s electricity customers. Utilities revenue was $7.8 billion, $7.8 billion and $6.9 billion for the years ended December 31, 2009, 2008 and 2007, respectively.

Performance drivers for Utilities include, but are not limited to, reliability of service; management of working capital; negotiation of tariff adjustments; compliance with extensive regulatory requirements; and in developing countries, reduction of commercial and technical losses. The results of operations of our Utilities businesses are sensitive to changes in economic growth and regulation and variations in weather conditions in the areas in which they operate.

Utilities face relatively little direct competition due to significant barriers to entry which are present in these markets. In certain locations, our distribution businesses face increased competition as a result of changes in laws and regulations which allow wholesale and retail services to be provided on a competitive basis. Competition is a factor in efforts to acquire existing businesses. In this arena, we compete against a number of other market participants, some of which have greater financial resources, have been engaged in distribution related businesses for longer periods of time and/or have accumulated more significant portfolios. Relevant competitive factors for

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our power distribution businesses include financial resources, governmental assistance, regulatory restrictions and access to non-recourse financing.

Renewables and Other Initiatives

In recent years, as demand for renewable sources of energy has grown, we have placed increasing emphasis on developing projects in wind, solar and other renewable initiatives including climate solutions, which develops and invests in projects that generate greenhouse gas offsets and or other renewable projects, and energy storage. In 2005, we started a wind generation business (AES Wind Generation), which currently has 30 plants in operation in four countries totaling over 1,400 MW in generation capacity and is one of the largest producers of wind power in the U.S. In addition, over 300 MW are under construction in three countries outside the U.S. In March 2008, we formed AES Solar Energy LLC (AES Solar), a joint venture with Riverstone Holdings, LLC (Riverstone), a private equity firm, which has since commenced commercial operations of nine plants totaling 33 MW of solar projects in Spain. We are also developing and implementing projects to produce GHG credits in Asia, Europe and Latin America. In the U.S., we formed Greenhouse Gas Services, LLC in 2008 as a joint venture with GE Energy Financial Services to create high quality verifiable emissions offsets for the voluntary U.S. market. We also have a line of business to develop and implement utility scale energy storage systems (such as batteries), which store and release power when needed. While none of these initiatives are currently material to our operations, we believe that in the future, they may become a material contributor to our operations. However, there are risks associated with these initiatives, which are further disclosed in Item 1A. Risk Factors of this Form 10-K. As further described in Our Organization and Segments below, some of these projects are managed within the region in which they are located, while others are managed as separate business units and reported as set forth below.

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 associated with our disclosure controls and internal controls over financial reporting;
- Risks associated with our high levels of indebtedness;
- Risks associated with our ability to raise needed capital;
- Risks associated with revenue and earnings volatility;
- Risks associated with our operations; and
- Risks associated with governmental regulation and laws.

The categories of risk identified above are discussed and explained 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

We believe our broad geographic footprint allows us to focus development in targeted markets with opportunities for new investment, and provides stability through our presence in more developed regions. In addition, our presence in each region affords us important relationships and helps us identify local markets with attractive opportunities for new investment. As a result, we have structured our organization into geographic regions, and each region is led by a regional president responsible for managing existing businesses. The regional presidents report to our Chief Operating Officer (COO), who in turn reports to our Chief Executive Officer (CEO). Both our CEO and COO are based in Arlington, Virginia.

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The Company s segment reporting structure is organized along our two lines of business (Generation and Utilities) and three regions: (1) Latin America & Africa; (2) North America; and (3) Europe, Middle East & Asia (collectively EMEA), which reflects how the Company manages the business internally. Additionally, AES Wind Generation is managed within our North America region. For financial reporting purposes, the Company has six reportable segments which include:

- Latin America Generation;
- Latin America Utilities;
- North America Generation;
- North America Utilities;
- Europe Generation;
- Asia Generation.

Corporate and Other The Company s Europe Utilities, Africa Utilities, Africa Generation and AES Wind Generation businesses as well as the Company s solar, climate solutions and energy storage initiatives 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 for further discussion of the Company s segment structure used for financial reporting purposes.

Latin America

Our Latin America operations accounted for 69%, 68% and 67% of consolidated AES revenue in 2009, 2008 and 2007, respectively. The following table provides highlights of our Latin America operations:

Countries	Argentina, Brazil, Chile, Colombia, Dominican Republic, El Salvador and Panama
Generation Capacity	11,740 Gross MW
Utilities Penetration	8.6 million customers (48,450 Gigawatt Hours (GWh))
Generation Facilities	55 (including 4 under construction)
Utilities Businesses	8
Key Generation Businesses	Gener, Tiete and Alicura
Key Utilities Businesses	Eletropaulo and Sul

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The graph below shows the breakdown between our Latin America Generation and Utilities segments as a percentage of total Latin America revenue and gross margin for the years ended December 31, 2009, 2008, and 2007. See Note 15 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 Gross Margin (a non-GAAP measure) and total assets by segment.

Revenue	Gross Margin
($ in billions)	($ in billions)

Latin America Generation. Our largest generation business in Latin America, AES Tietê (Tietê), located in Brazil, represents approximately 20% of the total generation capacity in the state of São Paulo and is the tenth largest generator in Brazil. AES holds a 24% economic interest in Tietê. In Argentina, we are the second largest private power generator contributing 11% of the country s total power generation capacity. In Chile, we are the second largest generator of power. We currently have four new generation plants under construction three coal plants in Chile and one hydro plant in Panama with a combined generation capacity of 1,163 MW.

Set forth below is a list of our Latin America Generation facilities:

Generation

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Alicura	Argentina	Hydro	1,050	99%	2000
Central Dique	Argentina	Gas/Diesel	68	51%	1998
Gener TermoAndes	Argentina	Gas/Diesel	643	71%	2000
Los Caracoles[1]	Argentina	Hydro	125	0%	2009
Paraná-GT	Argentina	Gas/Diesel	845	99%	2001
Quebrada de Ullum[1]	Argentina	Hydro	45	0%	2004
Rio Juramento Cabra Corral	Argentina	Hydro	102	99%	1995
Rio Juramento El Tunal	Argentina	Hydro	10	99%	1995
San Juan Sarmiento	Argentina	Gas/Diesel	33	99%	1996
San Juan Ullum	Argentina	Hydro	45	99%	1996
San Nicolás	Argentina	Coal/Gas/Oil	675	99%	1993
Tietê[2]	Brazil	Hydro	2,651	24%	1999
Uruguaiana	Brazil	Gas	639	46%	2000
Gener Electrica Santiago[3]	Chile	Gas/Diesel	479	64%	2000
Gener Energía Verde[4]	Chile	Biomass/Diesel	49	71%	2000
Gener Gener[5]	Chile	Hydro/Coal/Diesel	1,216	71%	2000
Gener Guacolda[6],[8]	Chile	Coal/Pet Coke	456	35%	2000
Gener Norgener	Chile	Coal/Pet Coke	277	71%	2000

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Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Chivor	Colombia	Hydro	1,000	71%	2000
Andres	Dominican Republic	Gas	319	100%	2003
Itabo[7]	Dominican Republic	Coal	295	50%	2000
Los Mina	Dominican Republic	Gas	236	100%	1996
Bayano	Panama	Hydro	260	49%	1999
Chiriqui Esti	Panama	Hydro	120	49%	2003
Chiriqui La Estrella	Panama	Hydro	48	49%	1999
Chiriqui Los Valles	Panama	Hydro	54	49%	1999
			11,740		

(1) AES operates this facility through management or operations and maintenance (O&M) agreements and owns no equity interest in this business.

(2) Tietê plants: Água Vermelha, Bariri, Barra Bonita, Caconde, Euclides da Cunha, Ibitinga, Limoeiro, Mog-Guaçu, Nova Avanhandava and Promissão.

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

(4) Gener Energia Verde Plants: Constitución, Laja and San Francisco de Mostazal.

(5) Gener Gener plants: Alfalfal, Laguna Verde, Laguna Verde Turbogas, Los Vientos, Maitenas, Nueva Ventanas (commenced commercial operations in February 2010), Queltehues, Santa Lidia, Ventanas and Volcán.

(6) Gener Guacolda plants: Guacolda 1, Guacolda 2 and Guacolda 3.

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

(8) Unconsolidated entities, the results of operations of which are reflected in Equity in Earnings of Affiliates.

Generation under construction

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Expected Year of Commercial Operations
Angamos	Chile	Coal	518	71%	2011
Campiche[1]	Chile	Coal	270	71%	TBD
Guacolda 4	Chile	Coal	152	35%	2010
Changuinola I	Panama	Hydro	223	83%	2011
			1,163		

(1) Construction of the Campiche facility is currently on hold. For further discussion please see Item 7. Management s Discussion and Analysis Key Trends and Uncertainties and Item 1A. Risk Factors of this Form 10-K, Our business is subject to substantial development uncertainties.

Latin America Utilities. Each of our Utilities businesses in Latin America sells electricity under regulated tariff agreements and has transmission and distribution capabilities but none of them has generation capability. AES Eletropaulo, a consolidated subsidiary of which AES owns a 16% economic interest and which has served the São Paulo, Brazil area for over 100 years, has approximately six million customers and is the largest electricity distribution company in Brazil in terms of revenue and electricity distributed. Pursuant to its concession agreement, AES Eletropaulo is entitled to distribute electricity in its service area until 2028. AES Eletropaulo s service territory consists of 24 municipalities in the greater São Paulo metropolitan area and adjacent regions that account for approximately 17% of Brazil s GDP and 39% of the population in the State of São Paulo. AES Sul (Sul), a wholly owned subsidiary, serves over one million customers. In El Salvador, our Utilities businesses provide electricity to over 76% of the country, serving approximately one million customers.

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Set forth below is a list of our Latin America Utilities facilities:

Distribution

Business	Location	Approximate Number of Customers Served as of 12/31/2009	GWh Sold in 2009	AES Equity Interest (Percent, Rounded)	Year Acquired
Edelap	Argentina	316,000	2,609	90%	1998
Edes	Argentina	165,000	849	90%	1997
Eletropaulo	Brazil	5,832,000	33,860	16%	1998
Sul	Brazil	1,151,000	7,702	100%	1997
CAESS	El Salvador	516,000	2,060	75%	2000
CLESA	El Salvador	304,000	786	64%	1998
DEUSEM	El Salvador	62,000	108	74%	2000
EEO	El Salvador	229,000	476	89%	2000
		8,575,000	48,450		

North America

Our North America operations accounted for 21%, 22% and 25% of consolidated revenue in 2009, 2008 and 2007, respectively. The following table provides highlights of our North America operations:

Countries	U.S., Puerto Rico, and Mexico
Generation Capacity	13,455 Gross MW
Utilities Penetration	470,000 customers (15,967 GWh)
Generation Facilities	19
Utilities Businesses	1 Integrated Utility (includes 4 generation plants)
Key Generation Businesses	Eastern Energy (NY), Southland and TEG/TEP
Key Utilities Business	IPL

The graph below shows the breakdown between our North America Generation and Utilities segments as a percentage of total North America revenue and gross margin for the years ended December 31, 2009, 2008, and 2007. See Note 15 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 Gross Margin (a non-GAAP measure) and total assets by segment.

Revenue

($ in billions)

Gross Margin

($ in billions)

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North America Generation. Approximately 60% of the generation capacity sold to third parties is supported by long-term power purchase or tolling agreements. Our North America Generation business consists of six gas-fired, ten coal-fired and three petroleum coke-fired plants in the United States, Puerto Rico and Mexico.

Our largest generation business is AES Southland. This business operates three gas-fired plants, representing generation capacity of 4,327 MW, in the Los Angeles basin under a long-term tolling agreement. In addition, in the Western New York power market, AES Eastern Energy operates four of our coal-fired plants, Cayuga, Greenidge, Somerset and Westover, representing generation capacity of 1,268 MW, providing power to this market under short-term contracts, as well as in the spot electricity market.

Set forth below is a list of our North America Generation facilities:

Generation

Business	Location	Fuel	Gross MW	AES Equity Ownership (Percent, Rounded)	Year Acquired or Began Operation
Mérida III	Mexico	Gas	484	55%	2000
Termoelectrica del Golfo (TEG)	Mexico	Pet Coke	230	99%	2007
Termoelectrica del Peñoles (TEP)	Mexico	Pet Coke	230	99%	2007
Southland Alamitos	USA CA	Gas	2,047	100%	1998
Southland Huntington Beach	USA CA	Gas	904	100%	1998
Southland Redondo Beach	USA CA	Gas	1,376	100%	1998
Thames	USA CT	Coal	208	100%	1990
Hawaii	USA HI	Coal	203	100%	1992
Warrior Run	USA MD	Coal	205	100%	2000
Red Oak	USA NJ	Gas	832	100%	2002
Cayuga	USA NY	Coal	306	100%	1999
Greenidge	USA NY	Coal	161	100%	1999
Somerset	USA NY	Coal	675	100%	1999
Westover	USA NY	Coal	126	100%	1999
Shady Point	USA OK	Coal	320	100%	1991
Beaver Valley	USA PA	Coal	125	100%	1985
Ironwood	USA PA	Gas	710	100%	2001
Puerto Rico	USA PR	Coal	454	100%	2002
Deepwater	USA TX	Pet Coke	160	100%	1986
			9,756		

North America Utilities. AES has one integrated utility in North America, IPL, which it owns through IPALCO Enterprises Inc. (IPALCO), the parent holding company of IPL. IPL generates, transmits, distributes and sells electricity to approximately 470,000 customers in the city of Indianapolis and neighboring areas within the state of Indiana. IPL owns and operates four generation facilities that provide more than 95% of the electricity it distributes. Two of the generation facilities are coal-fired plants. The third facility has a combination of units that use coal (base load capacity) and natural gas and/or oil (peaking capacity). The fourth facility is a small peaking station that uses gas-fired combustion turbine technology. IPL s gross generation capacity is 3,699 MW. Approximately 40% of IPL s coal is provided by one supplier with which IPL has long-term contracts. A key driver for the business is tariff recovery for environmental projects through the rate adjustment process. IPL s customers include residential, industrial, commercial and all other which made up 37%, 41%, 15% and 7%, respectively, of North America Utilities revenue for 2009.

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IPL s generation facilities

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
IPL[(1)]	USA IN	Coal/Gas/Oil	3,699	100%	2001

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

Distribution

Business	Location	Approximate Number of Customers Served as of 12/31/2009	GWh Sold in 2009	AES Equity Interest (Percent, Rounded)	Year Acquired
IPL	USA IN	470,000	15,967	100%	2001

Europe

The following table provides highlights of our Europe operations:

Countries	Czech Republic, Hungary, Kazakhstan, Netherlands, Spain, Turkey, Ukraine and the United Kingdom
Generation Capacity	6,274 Gross MW
Utilities Penetration	1.8 million customers (10,384 GWh)
Generation Facilities	18 (including 4 under construction)
Utilities Businesses	4
Key Generation Businesses	Kilroot, Tisza II
Key Utilities Businesses	Kievoblenergo and Rivneenergo

Our Utilities operations in Europe are discussed further under Corporate and Other below.

Europe Generation. Our Generation operations in Europe accounted for 5%, 7% and 7% of our consolidated revenue in 2009, 2008 and 2007, respectively. In 2007, we began commercial operation of AES Cartagena (Cartagena), our first power plant in Spain, with 1,219 MW capacity. The results of operations for Cartagena, an unconsolidated entity, are included in the Equity in Earnings of Affiliates line item on the Consolidated Statements of Operations. Today, AES operates four power plants in Kazakhstan which account for 8% of the country s total installed generation capacity. In May 2008, the Company completed the sale of two of its wholly-owned subsidiaries in Kazakhstan, AES Ekibastuz LLP (Ekibastuz), a coal-fired generation plant, and Maikuben West LLP (Maikuben), a coal mine. AES subsidiaries continued to manage the businesses under a management and operation agreement. In March 2009, the parties agreed to terminate the management and operation agreement effective at the end of the second quarter of 2009. See Note 15 Segment and Geographic Information in the Consolidated Financial Statements in Item 8 of this Form 10-K for revenue, Adjusted Gross Margin (a non-GAAP measure) and total assets by segment. Key business drivers of this segment are: foreign currency exchange rates, new legislation and regulations including those related to the environment.

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Set forth below is a list of our Europe Generation facilities:

Generation

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Bohemia	Czech Republic	Coal/Biomass	50	100%	2001
Borsod	Hungary	Biomass/Coal	71	100%	1996
Tisza II	Hungary	Gas/Oil	900	100%	1996
Tiszapalkonya	Hungary	Coal/Biomass	90	100%	1996
Shulbinsk HPP(1)	Kazakhstan	Hydro	702	0%	1997
Sogrinsk CHP	Kazakhstan	Coal	301	100%	1997
Ust Kamenogorsk HPP(1)	Kazakhstan	Hydro	331	0%	1997
Ust Kamenogorsk CHP	Kazakhstan	Coal	1,354	100%	1997
Elsta(2)	Netherlands	Gas	630	50%	1998
Cartagena(2)	Spain	Gas	1,219	71%	2006
Girlevik II-Mercan(2)	Turkey	Hydro	12	51%	2007
Yukari-Mercan(2)	Turkey	Hydro	14	51%	2007
Kilroot(3)	United Kingdom	Coal/Gas/Oil	600	99%	1992
			6,274		

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

Generation under construction

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Expected Year of Commercial Operation
I.C. Energy(1)	Turkey	Hydro	62	51%	2010
Maritza East I	Bulgaria	Coal	670	100%	2010
			732		

(1) Joint Venture with I.C. Energy. I.C. Energy Plants: Damlapinar Konya, Kepezkaya Konya, and Kumkoy Samsun. The joint venture is an unconsolidated entity, the results of operations of which are reflected in Equity in Earnings of Affiliates.

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Asia

Our Asia operations accounted for 5%, 4% and 2% of consolidated revenue in 2009, 2008 and 2007, respectively. Asia s Generation business operates 13 power plants with a total capacity of 6,044 MW in eight countries. In Asia, AES operates generation facilities only. See Note 15 Segment and Geographic Information in the Consolidated Financial Statements in Item 8 of this Form 10-K for revenue, Adjusted Gross Margin (a non-GAAP measure) and total assets by segment. The following table provides highlights of our Asia operations:

Countries	China, India, Jordan, Oman, Pakistan, the Philippines, Qatar and Sri Lanka
Generation Capacity	6,044 Gross MW
Utilities Penetration	None
Generation Facilities	13
Utilities Businesses	None
Key Businesses	Yangcheng and Masinloc

Asia Generation. Excluding our held for sale businesses in Pakistan and Oman, more than half of our generation capacity in Asia is located in China. In 1996, AES joined with Chinese partners to build Yangcheng, the first coal-by-wire power plant with the generation capacity of 2,100 MW. We also have a combined power and water desalination facility, the first such facility to be awarded to the private sector, in Qatar. This facility generates over 15% of the country s peak system capacity and 21.5% of the country s water supply. In April 2008, the Company completed the purchase of a 92% interest in a 660 MW coal-fired thermal power generation facility in Masinloc, Philippines (Masinloc). In September 2009, AES completed construction and launched commercial operation of the 380 MW combined-cycle Amman East power plant in Jordan.

Set forth below is a list of our generation facilities in Asia:

Generation

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Aixi	China	Coal	51	71%	1998
Chengdu(1)	China	Gas	50	35%	1997
Cili(1)	China	Hydro	26	51%	1994
Wuhu(1)	China	Coal	250	25%	1996
Yangcheng(1)	China	Coal	2,100	25%	2001
OPGC(1)	India	Coal	420	49%	1998
Amman East	Jordan	Gas	380	37%	2008
Barka(2)	Oman	Gas	456	35%	2003
Lal Pir(2)	Pakistan	Oil	362	55%	1997
Pak Gen(2)	Pakistan	Oil	365	55%	1998
Masinloc	Philippines	Coal	660	92%	2008
Ras Laffan	Qatar	Gas	756	55%	2003
Kelanitissa	Sri Lanka	Diesel	168	90%	2003
			6,044		

(1) Unconsolidated entities, the results of operations of which are reflected in Equity in Earnings of Affiliates.

(2) AES announced agreements to sell equity interests in these facilities on December 13, 2009. Until the transactions close, the businesses will be reported as held for sale businesses and their earnings will be reported as part of discontinued operations.

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Corporate and Other

Corporate and Other includes the net operating results from our Generation and Utilities businesses in Africa, Utilities businesses in Europe and AES Wind Generation and other renewables projects and costs associated with our development group. These operations are immaterial for the purposes of separate segment disclosure.

The following provides additional details about our utilities businesses in Africa and Europe, Africa generation and AES Wind Generation, which are reported within Corporate and Other for financial reporting purposes.

Europe Utilities. Our distribution businesses in the Ukraine and Kazakhstan together serve approximately 1.8 million customers.

Distribution

Business	Location	Approximate Number of Customers Served as of 12/31/2009	GWh Sold in 2009	AES Equity Interest (Percent, Rounded)	Year Acquired
Eastern Kazakhstan REC(1)(2)	Kazakhstan	459,000	3,444	0%	
Ust-Kamenogorsk Heat Nets(1)(3)	Kazakhstan	96,000		0%	
Kievoblenergo	Ukraine	835,000	4,671	89%	2001
Rivneenergo	Ukraine	405,000	2,269	84%	2001
		1,795,000	10,384		

(1) AES operates these businesses through management agreements and owns no equity interest in these businesses.

(2) Shygys Energo Trade, a retail electricity company, is 100% owned by Eastern Kazakhstan REC (EK REC) and purchases distribution service from EK REC and electricity in the wholesale electricity market and resells to the distribution customers of EK REC.

(3) Ust-Kamenogorsk Heat Nets provide transmission and distribution of heat with a total heat generating capacity of 224 Gcal.

Africa Generation. Set forth below is a list of our generation facilities in Africa.

Generation

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Dibamba	Cameroon	Heavy Fuel Oil	86	56%	2009
Ebute	Nigeria	Gas	304	95%	2001
			390		

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Africa Utilities. AES acquired a 56% interest in an integrated utility, Société Nationale d Electricité (Sonel), in 2001. Sonel generates, transmits and distributes electricity to over half a million people and is the sole distributor of electricity in Cameroon.

Set forth below is a list of the generation and distribution facilities of Sonel:

Sonel s generation facilities

Business	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Sonel[1]	Cameroon	Hydro/Diesel/Heavy Fuel Oil	931	56%	2001

(1) Sonel plants: Bafoussam, Bassa, Djamboutou, Edéa, Lagdo, Limbé, Logbaba I, Logbaba II, Oyomabang I, Oyomabang II, Song Loulou, and other small remote network units.

Sonel s distribution facility

Business	Location	Approximate Number of Customers Served as of 12/31/2009	GWh Sold in 2009	AES Equity Interest (Percent, Rounded)	Year Acquired
Sonel	Cameroon	571,000	3,360	56%	2001

Wind Generation. We own and operate 1,253 MW of wind generation capacity and operate an additional 215 MW capacity through operating and management agreements. Our wind business is located primarily in North America where we operate wind generation facilities that have generation capacity of 1,273 MW.

Set forth below is a list of AES Wind Generation facilities:

Generation

Business	Location	Power Source	Gross MW	AES Equity Interest (Percent, Rounded)	Year Acquired or Began Operation
Huanghua I[1],[3]	China	Wind	49	49%	2009
Hulunbeier[1],[3]	China	Wind	49	49%	2008
InnoVent[2],[3]	France	Wind	75	40%	2003-2009
North Rhins[4]	Scotland	Wind	22	100%	2010
Altamont	USA CA	Wind	43	100%	2005
Mountain View I & II[5]	USA CA	Wind	67	100%	2008
Palm Springs	USA CA	Wind	30	100%	2005
Tehachapi	USA CA	Wind	58	100%	2007
Storm Lake II[5]	USA IA	Wind	79	100%	2007
Lake Benton I[5]	USA MN	Wind	106	100%	2007
Condon[5]	USA OR	Wind	50	100%	2005
Armenia Mountain[5]	USA PA	Wind	101	100%	2009
Buffalo Gap I[5]	USA TX	Wind	121	100%	2006

Buffalo Gap II[5]	USA	TX	Wind	233	100%	2007
Buffalo Gap III[5]	USA	TX	Wind	170	100%	2008
Wind generation facilities[6]	USA		Wind	215	0%	2005
				1,468		

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(1) Joint Venture with Guohua Energy Investment Co. Ltd.
(2) InnoVent plants: Bignan, Chepy, Croixrault-Moyencourt, Frenouville, Gapree, Grand Fougeray, Guehenno, Hargicourt, Hescamps, LePortal, Les Diagots, Nibas, Plechatel, Saint-Hilaire la Croix and Valhoun. InnoVent owns various percentages of underlying projects.
(3) Unconsolidated entities, the results of operations of which are reflected in Equity in Earnings of Affiliates.
(4) North Rhins began commercial operation on January 1, 2010.
(5) AES owns these assets together with third party tax equity investors with variable ownership interests. The tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes that vary over the life of the projects. The proceeds from the issuance of tax equity are recorded as Noncontrolling Interest in the Company s Consolidated Balance Sheets.
(6) AES operates these facilities through management or O&M agreements and owns no equity interest in these businesses.

AES Wind Generation projects under construction

Business	**Location**	**Power Source**	**Gross MW**	**AES Equity Interest (Percent, Rounded)**	**Expected Year of Commercial Operation**
St. Nikolas	Bulgaria	Wind	156	89%	2010
Guohua Energy Investment Co. Ltd.[1]	China	Wind	149	49%	2010
InnoVent[2]	France	Wind	10	40%	2010
St. Patrick	France	Wind	35	100%	2010
			350		

(1) Joint Ventures with Guohua Energy Investment Co. Ltd. Guohua Energy plants: Huanghua II, Chenqi, and Dongqi.
(2) InnoVent plants: Audrieu, Boisbergues and Eurotunel. InnoVent owns various percentages of underlying projects.

Other. 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. AES Solar was formed in March 2008 to develop, own and operate solar installations. Since its launch, AES Solar has commenced commercial operations of 32 MW of solar projects in Spain, has 57 MW under construction in Italy, Greece and France, and has development potential in Bulgaria, India and the U.S.

Corporate and Other also includes general and administrative expenses related to corporate staff functions and initiatives, executive management, finance, legal, human resources and information systems which are not allocable to our business segments and the effects of eliminating transactions, such as self insurance charges, between the operating segments and corporate. See Note 15 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 Gross Margin (a non-GAAP measure) and total assets by segment.

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Financial Data by Country

The table below presents information, by country, about our consolidated operations for each of the three years ended December 31, 2009, 2008 and 2007, respectively, and property, plant and equipment as of December 31, 2009 and 2008, respectively. Revenue is recognized in the the country in which it is earned and assets are reflected in the country in which they are located.

	Revenue			Property, Plant & Equipment, net	
	2009	**2008**	**2007**	**2009**	**2008**
			(in millions)		
United States	$ 2,545	$ 2,745	$ 2,641	$ 7,016	$ 6,936
Non-U.S.:					
Brazil	5,394	5,501	4,748	5,799	4,206
Chile	1,239	1,349	1,011	2,321	1,540
Argentina	684	949	678	448	446
Pakistan[3]					
Dominican Republic	429	601	476	634	634
El Salvador	619	484	479	254	255
Hungary	317	466	344	196	211
Mexico	329	463	399	802	819
Ukraine	286	403	330	80	78
Cameroon	370	379	330	742	579
United Kingdom	241	342	235	433	308
Colombia	347	291	213	390	395
Puerto Rico	267	251	245	609	622
Kazakhstan	123	234	284	48	56
Panama	168	210	175	834	715
Sri Lanka	109	184	123	74	79
Qatar	163	161	178	501	526
Philippines[1]	250	148		765	731
Oman[4]					
Bulgaria[2]				1,835	1,329
Other Non-U.S.	239	197	125	516	414
Total Non-U.S.	11,574	12,613	10,373	17,281	13,943
Total	$ 14,119	$ 15,358	$ 13,014	$ 24,297	$ 20,879

(1) Acquired in April 2008; 2008 revenue represents results for a partial year.

(2) Currently under development; facility is not operational at this time.

(3) Excludes revenue of $470 million, $607 million and $396 million for the years ended December 31, 2009, 2008 and 2007, respectively, and property, plant and equipment of $36 and $204 million as of December 31, 2009 and 2008, respectively, related to Lal Pir and Pak Gen, which are reflected as discontinued operations and businesses held for sale in the accompanying consolidated statements of operation and consolidated balance sheets.

(4) Excludes revenue of $101 million, $105 million and $105 million for the years ended December 31, 2009, 2008 and 2007, respectively, and property, plant and equipment of $311 million and $321 million as of December 31, 2009 and 2008, respectively, related to Barka, which are reflected as discontinued operations and businesses held for sale in the accompanying consolidated statements of operation and consolidated balance sheets.

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Customers

We sell to a wide variety of customers. No individual customer accounted for 10% or more of our 2009 total revenue. In our generation business, we own and/or operate power plants to generate and sell power to wholesale customers such as utilities and other intermediaries. Our utilities sell to end-user customers in the residential, commercial, industrial and governmental sectors in a defined service area.

Employees

As of December 31, 2009 we employed approximately 27,000 people.

Executive Officers

The following individuals are our executive officers:

Paul Hanrahan, 52 years old, has been the President, CEO and a member of our Board of Directors since 2002. Prior to assuming his current position, Mr. Hanrahan was the Executive Vice President and COO. In this role, he was responsible for managing all aspects of business development activities and the operation of multiple electric utilities and generation facilities in Europe, Asia and Latin America. Mr. Hanrahan was previously the President and CEO of the AES China Generating Company, Ltd., a public company formerly listed on NASDAQ. Mr. Hanrahan also has managed other AES businesses in the United States, Europe and Asia. In March 2006, he was elected to the board of directors of Corn Products International, Inc. Prior to joining AES, Mr. Hanrahan served as a line officer on the U.S. fast attack nuclear submarine, USS Parche (SSN-683). Mr. Hanrahan is a graduate of Harvard Business School and the U.S. Naval Academy.

Andres R. Gluski, 52 years old, has been an Executive Vice President and COO of the Company since March 2007. Prior to becoming the COO of AES, Mr. Gluski was Executive Vice President and the Regional President of Latin America from 2006 to 2007. Mr. Gluski was Senior Vice President for the Caribbean and Central America (Venezuela, El Salvador, Panama and the Dominican Republic) from 2003 to 2006, President and CEO of La Electricidad de Caracas (EDC) from 2002 to 2003, CEO of AES Gener (Chile) in 2001 and Executive Vice President and CFO of EDC. Prior to joining AES in 2000, Mr. Gluski was Executive Vice President of Corporate Banking for Banco de Venezuela (Grupo Santander), Vice President for Santander Investment, and Executive Vice President and CFO of CANTV (subsidiary of GTE) in Venezuela. Mr. Gluski has also worked with the International Monetary Fund in the Treasury and Latin American Departments, served as Director General of the Ministry of Finance and Senior Economic Policy Advisor to the Minister of Planning in Venezuela. Mr. Gluski has served on numerous boards of directors, of both profit and not-for-profit companies, including the Venezuelan Investment Fund, AES Gener, Eletropaulo, Tiete, EDC, Dividendo para la Communidad (United Way) and the Institute of the Americas. Mr. Gluski is a graduate of Wake Forest University and holds an M.A and a Ph.D in Economics from the University of Virginia.

Ned Hall, 50 years old, has been an Executive Vice President, Regional President for North America and Chairman, Global Wind Generation and Energy Storage since June 2008. In December of 2008, Mr. Hall became Chairman, Greenhouse Gas Services, LLC, a joint venture between AES, GE and Mission Point. In August of 2009, Mr. Hall joined the Board of AES Solar Energy, Ltd., a joint venture between AES and Riverstone Holdings LLC. Prior to his current position, Mr. Hall was Vice President of the Company and President, Global Wind Generation from April 2005 to June 2008, Managing Director of AES Global Development from September 2003 to April 2005, and was an AES Group Manager from April 2001 to September 2003. Mr. Hall joined AES in 1988 as a Project Manager working in the Development Group and has held a variety of development and operating roles for AES, including assignments in the U.S., Europe, Asia and Latin America. He is a registered professional engineer in the State of Massachusetts. Mr. Hall holds a BSME degree from Tufts University and an MBA degree in finance/operations management from the MIT Sloan School of Management.

Victoria D. Harker, 45 years old, has been an Executive Vice President and Chief Financial Officer (CFO) since January 2006. Prior to joining the Company, Ms. Harker held the positions of Acting CFO, Senior

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Vice President and Treasurer of MCI from November 2002 to January 2006. Prior to that, Ms. Harker served as CFO of MCI Group, a unit of WorldCom Inc., from 1998 to 2002. Prior to 1998, Ms. Harker held several positions at MCI in the areas of finance, information technology and operations. In November of 2009, she was elected to the board of directors of Darden Restaurants, Inc. She has also been a member of the University of Virginia Board of Managers since 2007 and the board of the Wolf Trap Foundation for the Performing Arts since 2009. Ms. Harker received a Bachelor of Arts degree in English and Economics from the University of Virginia and a Masters in Business Administration, Finance from American University.

Brian A. Miller, 44 years old, is an Executive Vice President of the Company, General Counsel, and Corporate Secretary. Mr. Miller joined the Company in 2001 and has served in various positions including Vice President, Deputy General Counsel, Corporate Secretary, General Counsel for North America and Assistant General Counsel. In March of 2008, Mr. Miller joined the Board of AES Solar Energy, Ltd., a joint venture between AES and Riverstone Holdings LLC. In 2009, he joined the board of AgCert International Limited and AgCert Canada Holding Limited. Prior to joining AES, he was an attorney with the law firm Chadbourne & Parke, LLP. Mr. Miller received a bachelor s degree in History and Economics from Boston College and holds a Juris Doctorate from the University of Connecticut School of Law.

Rich Santoroski, 45 years old, became an Executive Vice President in February 2010 and has led the Company s Global Risk & Commodity Organization since February 2008. Prior to his current position, Mr. Santoroski was Vice President, Energy & Natural Resources, a business development group, and Vice President, Risk Management. Mr. Santoroski joined AES in January 1999 to lead AES Eastern Energy s commodity management. Prior to AES, Mr. Santoroski held various engineering, trading and risk management positions at New York State Electric & Gas, including leading the energy trading group. He graduated from Pennsylvania State University with a Bachelor of Science in Electrical Engineering, and earned an MBA and a Master of Science in Electrical Engineering from Syracuse University. Mr. Santoroski is a Licensed Professional Engineer in the State of New York.

Andrew Vesey, 54 years old, is Executive Vice President and Regional President of Latin America and Africa. He has held that position since April 2009. Prior to this, Mr. Vesey was Executive Vice President and Regional President for Latin America from March 2008 through March 2009 and Chief Operating Officer for Latin America from July 2007 through February 2008. Mr. Vesey also served as Vice President and Group Manager for AES Latin America, DR-CAFTA Region from 2006 to 2007, Vice President of the Global Business Transformation Group from 2005 to 2006, and Vice President of the Integrated Utilities Development Group from 2004 to 2005. Prior to joining the Company in 2004, Mr. Vesey was a Managing Director of the Utility Finance and Regulatory Advisory Practice at FTI Consulting Inc, a partner in the Energy, Chemicals and Utilities Practice of Ernst & Young LLP, and CEO and Managing Director of Citipower Pty of Melbourne, Australia. He received his BA in Economics and BS in Mechanical Engineering from Union College in Schenectady, New York and his MS from New York University.

Mark E. Woodruff, 52 years old, is an Executive Vice President and a Managing Director of the Company who is responsible for business development in Asia. Prior to his current position, Mr. Woodruff was Regional President of Asia & Middle East from March 2007 through January 2009, Vice President of North America Business Development from September 2006 to March 2007 and was Vice President of AES for the North America West region from 2002 to 2006. Mr. Woodruff has held various leadership positions since joining the Company in 1992. Prior to joining the Company in 1991, Mr. Woodruff was a Project Manager for Delmarva Capital Investments, a subsidiary of Delmarva Power & Light Company. Mr. Woodruff holds a Bachelor of Science degree in Mechanical and Aerospace Engineering from the University of Delaware.

How to Contact AES and Sources of Other Information

Our principal offices are located at 4300 Wilson Boulevard, Arlington, Virginia 22203. Our telephone number is (703) 522-1315. Our website address is *http://www.aes.com*. Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and any amendments to such reports filed

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pursuant to Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 are posted on our website. After the reports are filed with, or furnished to, the Securities and Exchange Commission (SEC), they are available from us free of charge. Material contained on our website is not part of and is not incorporated by reference in this Form 10-K.

Our CEO and our CFO have provided certifications to the SEC as required by Section 302 of the Sarbanes-Oxley Act of 2002. These certifications are included as exhibits to this Annual Report on Form 10-K.

Our CEO provided a certification pursuant to Section 303A of the New York Stock Exchange Listed Company Manual on May 21, 2009.

Our Code of Business Conduct (Code of Conduct) and Corporate Governance Guidelines have been adopted by our Board of Directors. The Code of Conduct is intended to govern, as a requirement of employment, the actions of everyone who works at AES, including employees of our subsidiaries and affiliates. Our Ethics and Compliance Department provides training, information, and certification programs for AES employees related to the Code of Conduct. The Ethics and Compliance Department also has programs in place to prevent and detect criminal conduct, promote an organizational culture that encourages ethical behavior and a commitment to compliance with the law, and to monitor and enforce AES policies on corruption, bribery, money laundering and associations with terrorists groups. The Code of Conduct and the Corporate Governance Guidelines are located in their entirety on our website at www.aes.com. Any person may obtain a copy of the Code of Conduct or the Corporate Governance Guidelines without charge by making a written request to: Corporate Secretary, The AES Corporation, 4300 Wilson Boulevard, Arlington, VA 22203. If any amendments to, or waivers from, the Code of Conduct or the Corporate Governance Guidelines are made, we will disclose such amendments or waivers on our website.

Regulatory Matters

Overview

In each country where we conduct business, we are subject to extensive and complex governmental regulations which affect most aspects of our business, such as regulations governing the generation and distribution of electricity and environmental regulations. These regulations affect the operation, development, growth and ownership of our businesses. Regulations differ on a country by country basis and are based upon the type of business we operate in a particular country.

Regulation of our Generation Businesses

Our Generation businesses operate in two different types of regulatory environments:

Market Environments. In market environments, sales of electricity may be made directly on the spot market, under negotiated bilateral contracts, or pursuant to PPAs. The spot markets are typically administered by a central dispatch or system operator who seeks to optimize the use of the generation resources throughout an interconnected system (cost of the least expensive next generation plant required to meet system demand). The spot price is usually set at the marginal cost of energy or based on bid prices. In addition, many of these wholesale markets include markets for ancillary services to support the reliable operation of the transmission system, such as regulation (a service that corrects for short-term changes in electricity use that could impact the stability of the power system). Most of our businesses in Europe, Latin America and the U.S. operate in these types of liberalized markets.

Other Environments. We operate Generation assets in certain countries that do not have a spot market. In these environments, electricity is sold only through PPAs with state-owned entities and/or industrial clients as the offtaker. Examples of countries where we operate in this type of environment include Jordan, Nigeria, Oman, Pakistan, Puerto Rico, Qatar and Sri Lanka.

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Regulation of our Distribution Businesses

In general, our distribution companies sell electricity directly to end users, such as homes and businesses and bill customers directly. The amount our distribution companies can charge customers for electricity is governed by a regulated tariff. The tariff, in turn, is generally based upon a certain usage level that includes a pass through of costs to the customer that are not controlled by the distribution company, including the costs of fuel (in the case of integrated utilities) and/or the costs of purchased energy, plus a margin for the value added by the distributor, usually calculated as a fair return on the fair value of the company s assets. This regulated tariff is periodically reviewed and reset by the regulatory agency of the government. Components of the tariff that are directly passed through to the customer are usually adjusted through an automated process. 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 often unregulated 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 the distribution system. Most of our utilities operate as monopolies within exclusive geographic areas set by the regulatory agency and face very limited competition from other distributors.

Set forth below is a discussion of certain regulations we face in countries where we do business. In each country, the regulatory environment can pose material risks to our business, its operations and/or its financial condition. For further discussion of those risks, see the Risk Factors in Item 1A. of this Form 10-K.

Latin America & Africa

Argentina. Argentina has one main national interconnected system. The National Electrical Regulating Agency is responsible for ensuring transmission and distribution companies comply with the concessions granted by the Argentine government and approving distribution tariffs. The regulatory entity authorized to manage and operate the wholesale electricity market in Argentina is Compañía Administradora del Mercado Mayorista Eléctrico, Sociedad Anónima, (CAMMESA), in coordination with the policies established by the National Secretariat of Energy.

CAMMESA performs load dispatching and clears commercial transactions for energy and power. Sales of electricity may be made on the spot market at the marginal cost of energy to satisfy the system s hourly demand, or in the wholesale energy market under negotiated term contracts. As a result of the gas crisis earlier this decade, this mechanism was modified in 2003 by Resolution 240/03. At present, the price is determined as if all generating units in Argentina were operating with natural gas, even though they may be using other, more expensive, alternative fuels. In the case of generators using alternative fuels, CAMMESA pays the total variable cost of production, which may exceed the established spot price. Additionally, in the spot market, generators are also remunerated for their capacity to generate electricity in excess of supply agreements or private contracts executed by them.

As the result of a political, social and economic crisis, the Argentine government has adopted many new economic measures since 2002, by means of the Emergency Law 25561 issued on January 6, 2002, extended by Law Nº 26.456 issued on December 16, 2008 until December 31, 2009, and then by Law 26563, passed on November 25, 2009, until December 31, 2010. These regulations effectively terminated the use of the U.S. Dollar as the functional currency of the Argentine electricity sector. During 2004, the Energy Secretariat reached agreements with natural gas and electricity producers to reform the energy markets. In the electricity sector, the Energy Secretariat passed Resolution 826/2004, inviting generators to contribute a percentage of their sales margins to fund the development and construction of two new combined cycle power plants to be installed by 2008/2009. The time period for the funding was set from January 2004 through December 2006 and was subsequently extended through December 2007. During 2008, both power plants have started operation of the gas turbines, and during the first half of 2010 it is expected that the steam turbines will be installed and the plants will start to operate in combined cycle mode. In exchange, the Government committed to reform the market regulation to match the pre-crisis rules prevailing before December 2001. Additionally, participating generators will receive a pro-rata ownership share in the new generation plants after ten years. In July 2008, the Energy

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Secretariat passed Resolution 724, which creates a new mechanism to collect the account receivables generated after the end of the period established for the funding of the combined cycle power plants mentioned above, by investing a percentage of the funds to be collected. An agreement was executed with the Energy Secretariat in December 2008 which causes the government to pay 65% of account receivables in exchange for the investment discussed above.

Prior to the Emergency Law, distribution companies were granted long-term concessions (up to 99 years) which provided, directly or indirectly, tariffs based upon U.S. Dollars and adjusted by the U.S. consumer price index and producer price index. Under the new regulations, tariffs are no longer linked to the U.S. Dollar and U.S. inflation indices. As a consequence of the emergency declared by the above-mentioned laws and its resulting regulatory framework, the tariffs of all distribution companies were converted to Argentinean Pesos and were frozen at the Argentinean Peso national rate as of December 31, 2001. In October 2003, the Argentine Congress established a procedure for renegotiation of the public utilities concessions.

On November 12, 2004, EDELAP, an AES distribution business, signed a Letter of Understanding with the Argentine government in order to renegotiate its concession contract and to start a tariff reform process, which was ratified by the National Congress on May 11, 2005. Final government approval was obtained on July 14, 2005. As a first step during this process, a Distribution Value Added (DVA) increase of 28%, effective February 1, 2005, was granted. On October 24, 2005, EDEN and EDES, two AES distribution businesses, signed a Letter of Understanding with the Ministry of Infrastructure and Public Services of the Province of Buenos Aires to renegotiate their concession contracts and to start a tariff reform process, which was formally approved on November 30, 2005. An initial 19% DVA increase became effective in August 2005 and an additional 8% DVA increase became effective in January 2007. On July 31, 2008, ENRE (the national electricity regulatory agency) issued Resolution 324 that granted EDELAP a tariff increase DVA of approximately 18%. Upon execution of these Letters of Understanding, AES agreed to postpone or suspend certain international claims against the Argentine government. However, these Letters of Understanding provide that if the government does not fulfill its commitments, AES may restart the international claim process. AES has postponed any action until the tariff reset is finalized.

In addition, the Government established that a process to establish the RTI (integral tariff reset) should take place during February 2009. In addition, the Government established that a process to establish the RTI (integral tariff reset) will take place during February 2009 and on September 12, 2009 EDELAP submitted the tariff reset proposal to the ENRE. ENRE is considering the tariff proposals submitted by the federal distribution companies.

On August 25, 2008, the Province of Buenos Aires issued Decree 1578, which granted EDES a tariff increase DVA of approximately 49%. This decree granted a rise in the tariff at all levels of consumption.

Brazil. Brazil has one main interconnected electricity system, the National Interconnected System. The power industry in Brazil is regulated by the Brazilian government, acting through the Ministry of Mines and Energy and the National Electric Energy Agency, (ANEEL), an independent federal regulatory agency. ANEEL supervises concessions and authorizations for electricity generation, transmission, trading and distribution, including the setting of tariff rates, and supervising and auditing of concessionaires.

On March 15, 2004, the Brazilian government launched a proposed new model for the Brazilian power sector. The New Power Sector Model created two market environments: (1) the regulated contractual market for the distribution companies, and (2) the free contract environment market, designed for traders and other large volume users.

Distribution Companies. AES has two distribution businesses in Brazil AES Eletropaulo, serving approximately six million customers in the São Paulo area, and AES Sul, serving over one million customers in the state of Rio Grande do Sul. Under the New Power Sector Model, every distribution utility is obligated to contract to meet 100% of its energy requirements in the regulated contractual market, through energy auctions from new proposed generation projects or existing generation facilities. Bilateral contracts are being honored, but cannot be renewed.

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The tariff charged by distribution companies to captive customers is composed of a non-manageable cost component (Parcel A), which includes energy purchase costs and charges related to the use of transmission and distribution systems and is directly passed through to customers, and a manageable cost component (Parcel B), which includes operation and maintenance costs based on a reference company (a model distribution company defined by ANEEL), recovery of depreciated assets and a component for the value added by the distributor (calculated as net asset base multiplied by pre-tax weighted average cost of capital). Parcel B is reset every three to five years depending on the specific concession. There is an annual tariff adjustment to pass through Parcel A costs to customers and to adjust the Parcel B costs by inflation less an efficiency factor (X-Factor). Distribution companies are also entitled to extraordinary tariff revisions, in the event of significant changes to their cost structure.

On May 16, 2002, ANEEL issued Order 288, a regulation that stipulated the retroactive obligation to the exposition relief mechanism, a tool that forbids the selling of energy from Itaipu Generating Co. (a hydro power plant in Paraguay from which Brazil imports a significant portion of its power) in the spot market and changed the calculation of electricity pricing in the Brazilian wholesale market. Due to its negative impact, AES Sul filed a lawsuit seeking to annul Order 288, and as soon as the case went to court, AES Sul was granted a preliminary injunction that ordered ANEEL to review the Brazilian Electric Energy Commercialization Chamber (CCEE) calculations and liquidation, an injunction that was later suspended. If AES Sul obtains a favorable final verdict, it will have a positive impact of about R$437.8 million (historic values referring to 2001 and 2002) or approximately $251.4 million, but if AES Sul s requests are not granted, under Order 288 AES Sul will owe a net amount of approximately R$142 million or approximately $81.6 million at December 31, 2009. All amounts are reserved in AES Sul s books, including the amount owed to CCEE in the event Sul loses the case.

At ANEEL s Public Meeting on June 30, 2009, AES Eletropaulo was granted a 14.88% average tariff increase, effective on July 4, 2009. The effects of the completion of AES Eletropaulo s second tariff reset process, which was provisional since 2007, were reflected in this tariff adjustment process.

On November 27, 2009, ANEEL initiated a Public Hearing to revise the tariff reset methodology and eliminate effects from market variance on Parcel A costs (purchased energy, transmission costs and sector charges). Current tariff methodology allows distribution companies to achieve gains or losses depending on market variation. The original concept of the above-mentioned Public Hearing is to neutralize these effects over Parcel A costs. On February 2, 2010 ANEEL approved the amendment of the Concession Contract, capturing market variance effects only over the sector charges (purchased energy and transmission costs were not affected). AES Eletropaulo and AES Sul will analyze and determine whether they will enter into this amendment.

Additionally ANEEL discussed through the Public Hearing the partition of the extraordinary tariff reset (RTE) between Generation and Distribution companies. The RTE was basically designed to recover revenue losses of Distribution companies and energy purchase costs called Free Energy of Generation companies, both during the rationing period which occurred in 2001 as a result of regulatory, market, and weather related conditions. RTE period of application for AES Eletropaulo was limited to 70 months, which was not sufficient to recover its losses. The Public Hearing process was concluded on January 12, 2010, generating a negative pre tax impact to AES Eletropaulo of R$6.8 million. The effects of the above mentioned resolution on AES Tietê will only be quantified after ANEEL receives all Free Energy information from Distribution Companies and releases the consolidated impact.

Generation Companies. AES has two generation businesses in Brazil AES Tietê, a 2,651 MW hydro-generation facility and AES Uruguaiana, a 639 MW generation facility. Under the New Power Sector Model and in order to optimize the generation of electricity through Brazil s nationwide system, generation plants are allocated a generating capacity referred to as assured energy or the amount of energy representing the long-term average energy production of the plant defined by ANEEL. Together with the system operator, ANEEL establishes the amount of assured energy to be sold by each plant. The system operator determines generation dispatch which takes into account nationwide electricity demand, hydrological conditions and system

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constraints. In order to mitigate risks involved in hydroelectric generation, a mechanism is in place to transfer surplus energy from those who generated in excess of their assured energy to those who generated less than their assured energy. The energy that is reallocated through this mechanism is priced pursuant to an energy optimization tariff, designed to optimize the use of generation available in the system.

AES Tietê is allowed to sell electric power within the two environments, maintaining the competitive nature of the generation. All the agreements, whether entered in the ACR (Regulated Contracting Environment) or in the ACL (Free Contracting Environment), are registered in the CCEE and they serve as basis for the accounting posting and the settlement of the differences in the short-term market. Generation companies must provide physical coverage from their own power generation for 100% of their sale contracts. The verification of physical coverage is accomplished on a monthly basis, based on generation data and on sale company contracts of the last 12 months. The failure to provide physical coverage exposes the generating company to the payment of penalties.

Beginning in 2003, all of AES Tietê s assured energy has been sold to AES Eletropaulo. The PPA entered into with AES Eletropaulo expires on December 31, 2015, and requires that the price of energy sold be adjusted annually based on the Brazilian inflation (IGPM) variation. In October 2003, AES Tietê and AES Eletropaulo executed an amendment to extend the PPA through June 2028. However, this amendment was not approved by ANEEL. In response, AES Eletropaulo filed a suit against ANEEL and is currently awaiting the first-instance judgment. If the PPA were terminated, AES Tietê would only be allowed to sell in the ACR or ACL, being subject to market prices. Based on the current rules concerning the purchase and sale of energy through the auction process, and because such rules remain in effect until 2015, the selling price may significantly differ from the current price adjusted under the terms of the existing PPA.

AES Tietê s concession agreement with the State of São Paulo for its generation plant includes an obligation to increase generation capacity by 15% originally to be accomplished by the end of 2007. AES Tietê, as well as other concessionaire generators, was not able to meet this requirement due to regulatory, environmental and hydrological constraints, and requested an extension of the term. Currently, the matter is under consideration by the Government of the State of São Paulo (related to the increased capacity), after a decision by the Board of Officers of ANEEL, that ANEEL is not the appropriate authority to consider the extension, since the expansion obligation derives from the purchase and sale agreement between AES Tietê and the Government of São Paulo, and not from the concession agreement. AES Tietê is negotiating new conditions and a new deadline to fulfill the expansion requirement. There is a dispute alleging that AES Tietê failed to increase its generation capacity as established in the concession agreement. The dispute seeks to determine the application of penalties related to the concession agreement, and also to determine its termination. Judicial summons have been received and, in October 2008, AES Tietê presented its defense. Upon the Prosecutor s Office request, on September 30, 2009 the Court ordered the Plaintiffs to specify the individuals that should also be named as Defendants.

AES Uruguaiana has been impacted by the energy crisis in Argentina, primarily through natural gas supply restrictions. During this period, AES Uruguaiana has been forced to purchase energy from the spot market and through bilateral contracts in order to satisfy its alleged obligations under the PPAs with the distribution companies. In August 2008, the Argentinean gas supplier sent a notification to AES Uruguaiana declaring force majeure under the gas supply agreement. AES Uruguaiana extended the effects of such force majeure to the PPAs with the distribution companies. After such declaration by the Argentinean gas supplier, AES Uruguaiana started negotiations with the four distribution companies to reduce the amount of energy contracted under the PPAs and resolve these matters. From August 2008 to December 2008, AES Uruguaiana and the distribution companies entered into amendments to reduce the energy amounts under the PPAs to the level of the bilateral agreements executed by AES Uruguaiana, suspend such agreements by December 2009 and settle all pending matters. Three of these distribution companies sought and received a decision by ANEEL declaring that they were entitled to involuntary exposures, which allows these distribution companies to purchase replacement energy in the market and recover the related additional costs, if any, through their tariffs.

Cameroon. The law governing the Cameroonian electricity sector was passed in December 1998. The regulator is the Electricity Sector Regulatory Agency (ARSEL) and its role is regulating and ensuring the proper functioning of the electricity sector, supervising the process of granting concessions, licenses and authorizations to operators, monitoring the application of the electricity regulation by the operators of the sector, approving and/or publicizing the regulated tariffs in the sector and safeguarding the interests of electricity operators and consumers. ARSEL has the legal status of a Public Administrative Establishment and is placed under the dual technical supervisory authority of the Ministries charged with electricity and finance.

The concession agreement of July 2001 between the Republic of Cameroon and Sonel covers a twenty-year period. The first three years constituted a grace period to permit resolution of issues existing at the time of the privatization. In 2006, Sonel and the Cameroonian government signed an amended concession agreement. The amendment updates the schedule for investments to more than double the number of people Sonel serves over the next 15 years and provides for upgrading the generation, transmission and distribution system. Additionally, the concession agreement amended the tariff structure that results in an electricity price based on a reasonable return on the generation, transmission and distribution asset base and a pass through of a portion of fuel costs associated with increased thermal generation in years when hydrology is poor. The amended concession agreement has also reduced the cost of connection to facilitate access to electricity in Cameroon.

Chile. In Chile, except for the small isolated systems of Aysén and Punta Arenas, generation activities are principally in two electric systems: the Central Interconnected Grid (known as the SIC), which supplies approximately 92% of the country s population; and the Northern Interconnected Grid (known as the SING), where the principal users are mining and industrial companies.

The keystones of the electricity regulation are: 1) a regulated compulsory marginal cost dispatch based on audited variable costs; 2) a contract-based wholesale generation market; 3) an open access regime for transmission with benchmark regulation for existent transmission lines and open bids for new lines; 4) benchmark regulation for the distribution grid; and 5) electricity retailing by distribution companies in their exclusive concession areas.

Electricity generation in each of these grids is coordinated by the respective independent Economic Load Dispatch Center (CDEC) in order to minimize operational costs and ensure the highest economic efficiency of the system, while fulfilling all quality of service and reliability requirements established by current regulations. In order to satisfy demand at the lowest possible cost at all times, each CDEC orders the dispatch of generation plants based strictly on variable generation costs, starting with the lowest variable cost, and does so independent of the contracts held by each generation company. Thus, while the generation companies are free to enter into supply contracts with their customers and are obligated to comply with such contracts, the energy needed to satisfy demand is always produced by the CDEC members whose variable production costs are lower than the system s marginal cost at the time of dispatch. For this reason, in each hour a given generator is either a net supplier to the system or a net buyer. Net buyers pay net suppliers the system s marginal cost. In addition, the Chilean market is designed to include payments for capacity (or firm capacity), which are explicitly paid to generation companies for contributing to the system s sufficiency. The cost of investment and operation of transmission systems are borne by generation companies and consumers (regulated tolls) in proportion to their use.

The Chilean Ministry of Economy, Development and Reconstruction grants concessions for the provision of the public service of electric distribution and the National Commission for the Environment administers the system for evaluating the environmental impact of projects. Concessions are not required from government agencies to build and operate thermoelectric plants. The National Energy Commission establishes, regulates and coordinates energy policy. The Superintendency of Electricity and Fuels oversees compliance with service quality and safety regulations. The General Water Authority issues the rights to use water for hydroelectric generation plants. The Chilean electric system includes a Panel of Experts, an independent technical agency whose purpose is to analyze and resolve in a timely fashion conflicts arising between companies within the electric sector and among one or more of these companies and the energy authorities.

Power generation is based primarily on long-term contracts between generation companies and customers specifying the volume, price and conditions for the sale of energy and capacity. The law recognizes two types of customers for generation companies: unregulated customers and regulated customers. Unregulated customers are principally consumers whose connected capacity is higher than 2 MW, and consumers whose connected capacity is between 500 kW and 2 MW who have selected the unregulated pricing mechanism for a period of four years. These customers are not subject to price regulation; therefore, generation and distribution companies are able to freely negotiate prices and conditions for electricity supply with them. Regulated customers are those whose connected capacity is less than or equal to 500 kW, and those with connected capacity between 500 kW and 2 MW who have selected also for four years the regulated pricing system.

The distinct electricity sector activities are regulated by the General Electricity Services Law, DFL No. 1/1982 enacted by the Mining Ministry, with its subsequent amendments: Law No. 19,490 (2004, known as the Short Law I) and Law No. 20,01/005, or the Short Law II , which did not modify the foundation of Chile s stable electricity sector model. These laws were rewritten and systematized under DFL No. 4/2007. Sector activities are also governed by the corresponding technical regulations and standards.

In accordance with the amendment to the electricity law enacted in May 2005, new contracts assigned by distribution companies for consumption from 2010 onward must be awarded to generation companies based on the lowest supply price offered in public bid processes. These prices called long-term node prices , include indexation formulas and are valid for the entire term of the contract, up to a maximum of 15 years. More precisely, the long-term energy node price for a particular contract is the lowest energy price offered by the generation companies participating in each respective bid process, while the long-term capacity node price is that set in the node price decree in effect at the time of the bid.

The *Tokman Law*, which was enacted in September 2007, requires that generation companies must continue to supply electricity to distribution companies whose supply contract may be terminated as a result of bankruptcy of the distribution company, its generation supplier, or the anticipated termination of the power purchase contract due to an arbitration award or court decision. The law states that in these situations, if the distribution company is not able to procure a new contract, all generation companies in the system must then supply the distribution company at node prices based on the generator s respective participation in the grid.

Another statute, Law 20,257, was enacted in April 2008. Law 20,257 promotes non-conventional renewable energy sources, such as solar, wind, small hydroelectric and biomass energy. The law requires that a percentage of the new power purchase contracts held by generation companies after August 31, 2007, be supplied from renewable sources. The required energy percentage begins at 5% for the period 2010-2014, and gradually increases to a maximum of 10% in 2024. A penalty is applied for each kWh not supplied in accordance with the law. This law will be in force for 25 years beginning in 2010. Our businesses in Chile have developed a plan for complying with this law, which includes the sale of certain water rights, the purchasers of which have agreed to build a small hydroelectric plant and sell the energy to Gener at a fixed price. In December 2009, the governmental environmental agency published a draft of a potential new ruling which will regulate the emissions from thermal power plants of NO_x, SO_2, PM and metals. This ruling would impose high-quality standards over the system. This draft will enter in a discussion process during 2010. AES Gener is analyzing the potential impact of this regulation, and an estimation of the impact can only be established when the final regulation is issued. Additionally, at the end of 2009 a law was approved that changes the governmental administrative structure and creates the Ministry of Energy. The new Ministry of Energy will gather several agencies related to energy issues and depend on the Ministries of Mining and Economy, such as the National Energy Commission, the Electricity and Fuel Superintendent and the Chilean Nuclear Commission, among others, in order to provide a better coordination of energy affairs. The Ministry of Energy will also oversee a new Energy Efficiency agency.

Colombia. Colombia has one main national interconnected system (the SIN). In 1994 the Colombian Congress issued the laws of Domiciliary Public Services and the Electricity Law, which set the institutional arrangement and the general regulatory framework for the electricity sector. The Regulatory Commission of

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Electricity and Gas (CREG) was created to foster the efficient supply of energy through regulation of the wholesale market, the natural monopolies of transmission and distribution, and by setting limits for horizontal and vertical economic integration.

The wholesale market is organized around both bilateral contracts and a mandatory pool and spot market for all generation units larger than 20 MW. Each unit bids its availability quantities for a 24-hour period with one bid price set for those 24 hours. The dispatch is arranged from lowest to highest bid price and the spot price is set by the marginal price.

The spot market started in July 1995, and in 1996 a capacity payment was introduced for a term of 10 years. In December 2006, a regulation was enacted that replaced the capacity charge with the reliability charge and established two implementation periods. The first period consists of a transition period from December 2006 to November 2012, during which, the price is equal to $13.045 per megawatt hour (MWh) and volume is determined based on firm energy offers which are prorated so that the total firm energy level does not exceed system demand. The second period, in which the reliability charge will be determined based on the energy price and volume offers submitted by new market participants bidding for new capacity for the system, begins in December 2012. The first reliability charge auction was held in May 2008 with the following results: (i) the reliability charge for existing plants for the period between December 2012 and November 2013 will be $13.998 per MWh; (ii) for new plants that successfully participated in the auction, the charge will be paid for 20 years starting December 2012; (iii) three new projects won the auction for a total capacity of 429.6 MW starting in 2012.

Furthermore, the CREG issued a proposal to create the Organized Regulated Market (MOR). The MOR will replace current bilateral contracts (assigned between traders/utilities and generators) for a centralized auction in which the System Operator buys energy for all regulated customers attended by the traders/utilities. The main provisions contained in the proposal include: (i) it is mandatory for all traders/utilities to buy energy at the auction price and it is voluntary for sellers (generators and trade companies) to offer energy in each auction; (ii) one price for the energy sales in the auction; (iii) the auctions are held one year before the actual dispatch moment and the commitment period of the auction is one year; and (iv) the proposal is to establish four auctions in each year, in order to cover the annual demand. We expect that a definitive resolution on this matter will be issued in the first half of 2010.

During the second half of 2009, due the to El Niño Phenomenon, which causes low levels of rainfall in Colombia, the Ministry of Mines and Energy and CREG issued a series of temporary measures intended to guarantee reliability of the energy sector including (i) establishment of a priority scale for the assignment of gas during scarcity periods; (ii) securing availability of thermal plants and forcing some of them to generate for electrical security reasons; and (iii) continuous follow-up of the market in order to implement additional measures in case of increase of the probability of energy rationing in the system. These measures have affected the spot prices in the market, pressuring prices down and, therefore, distorting the current scarcity conditions. For AES Chivor, these conditions did not have a negative impact on the 2009 results given AES Chivor s reservoir levels and contracts for the year. Nevertheless, AES Chivor and other generators have opposed the measures and are currently requesting the government and regulator restore the normal market conditions as soon as possible.

Dominican Republic. The Dominican Republic has one main interconnected system with 3,000 MW of installed capacity and four isolated systems. Under current regulations, the Dominican government retains ultimate oversight and regulatory authority as well as control over the transmission grid and the hydroelectric facilities in the country. In addition, the government shares ownership in certain generation assets and all distribution assets. The Dominican government s oversight responsibilities for the electricity sector are carried out by the National Energy Commission and the Superintendency of Electricity.

The wholesale electricity market in the Dominican Republic commenced operations in June 2000. This market includes a spot market and contract market. All participants in the Dominican electric system with available units are put in the spot market in order of merit for dispatch based on lowest marginal cost. The order of merit determines the order in which each participant is dispatched. The order of merit is effective for one week. The price to be paid for the electricity corresponds to the marginal cost of the last dispatched unit. In addition to the spot market, participants may execute private contracts in which they agree to specific price, energy, and capacity transactions. Currently, the wholesale market has 80% of the transactions under contracts and the remaining 20% in the spot market.

The regulatory framework in the Dominican electricity market establishes a methodology for calculating the firm capacity, which is the supply that can be economically dispatched by a generating unit during peak demand, provided that the unit has a certain unavailability (mechanical in the case of thermal power plants, and primarily hydrological in the case of hydroelectric power plants). The total firm capacity of the electric system in a year is equal to the peak demand of that year. The capacity payment is regulated as the average fixed cost (monthly capital cost of the investment cost plus fixed operational and maintenance cost) of an oil-fired open cycle gas turbine, multiplied by 10% to take into account a reserve margin.

The financial crisis in the Dominican Republic during 2004 caused a financial crisis in the electricity sector. The inability to pass through higher fuel prices and the costs of devaluation led to a gap between collections at the distribution companies and the amounts required to pay the generators. In 2005, the government committed itself to stay current with its energy bills and also to cover the potential deficit of distribution companies. During 2005, 2006, and 2007, the Government was paying both the subsidies and its own energy bills on time. In December 2006, a bill with the primary goal of supporting fraud prosecution was sent to Congress by the Executive Branch. This bill was approved in July 2007 and is expected to help the sector reach financial sustainability by: criminalizing electrical fraud; setting new limits to non-regulated users in order to protect the distribution companies market; allowing for service cutoff after only one bill due and unpaid; and classifying as a national security breach the intentional damage or interruption of the national electricity grid.

Despite these improvements, the electricity sector has not completely recovered from the financial crisis of 2004. In 2006, the electricity sector needed $530 million in subsidies from the government to cover current operations. In 2007, the sector needed more than $630 million and, at projected fuel prices, the government budgeted subsidies of $800 million for 2008. In 2008, because petroleum and all other fuels doubled in price, the subsidy of $800 million was not enough to cover additional costs, which reached $1.2 billion. The Government has been trying to raise more funds, by allocating funds from the national budget, such as a recent approval of an additional $300 million in electricity subsidies supplementing 2008. In addition, the Government has been trying to obtain credit from local banks and multilateral institutions. In 2009, the Government paid the total debt for 2008 through a sovereign bond issuance.

Trying to reverse the situation generated by freezing tariffs in 2005, in June and July 2009, the Superintendence of Electricity (SIE) increased the distribution tariffs by an average of 5.7%. As of September 30, 2009, the accumulated increment is 12.1%. In addition, on October 12, 2009, the Government signed a Letter of Intent for a Stand-By Agreement of $1.7 billion with the International Monetary Fund (IMF). This agreement will include structural changes for the electricity sector and a plan to pay the current debt to the generators. On November 9, 2009, the IMF approved the agreement. The following actions have to be executed by the Dominican Government to carry on with the agreement:

- Design a strategy to rationalize and limit tax exemptions and strengthen tax administration;
- Adjustments in tariffs and tariff system application to cover the costs of generation and distribution;
- Phasing out the general electricity subsidy by 2012 and targeting the poor;
- Reduce losses and improve measurement techniques to reduce electricity theft;
- Improving the management of distribution companies;
- Creation of a special trust fund to implement government payments to generation and distribution companies;

Application of an external audit of the finances of state enterprises in the distribution of corporate unit; and

Develop a plan to invest in new generation capacity and distribution.

Financial resources derived from the IMF agreement have begun to flow to the electricity generation players in the country and, in December 2009, the sector received more than $300 million in payment for outstanding debts.

In October of 2006, Corporación Dominicana de Empresas Electricas Estatales (CDEEE), the state-owned transmission and hydro company, began making public statements that it intends to seek to compel the renegotiation and/or rescission of long-term PPAs with certain power generating companies in the Dominican Republic. Although the details concerning CDEEE s statements are unclear and no formal government action has been taken, AES holds ownership interests in three power generation facilities in the country (AES Andres, Itabo and Dominican Power Partners) that could be adversely affected by the actions taken by the CDEEE, if any.

El Salvador. Electricity generators and distribution companies in El Salvador are linked through a single, main interconnected system managed by the Transactions Unit (UT). The transmission system is operated by ETESAL, a state-owned company. The El Salvador wholesale electricity market is comprised of: (1) a contract market based on contracts between electricity generators, distributors and trading companies and (2) a spot market for uncontracted electricity based upon bids from spot market participants specifying prices at which they are willing to buy or sell electricity.

El Salvador has seven electricity distribution companies, five went to private ownership as part of the privatization process that took place in 1998 and the additional two, representing less than 1% of the market, were created after the electricity law allowed competition in the sector. AES controls four of these five distribution companies, encompassing about 80% of the national territory, serving about 1,110,000 customers. El Salvador s electricity industry is regulated under the General Electricity Law enacted in October 1996 and subsequently amended twice in June 2003 and in October 2007. The Superintendencia General de Electricidad y Telecomunicaciones (SIGET) is an independent regulatory authority that regulates the electricity and telecommunications sectors in El Salvador.

The maximum tariff to be charged by distribution companies to regulated customers is subject to the approval of SIGET. The components of the electricity tariff are (a) the average energy price (energy charge), (b) the charges for the use of the distribution network (distribution charge), and (c) customer service costs (service charge). Both the distribution charge and service charge are based on average capital costs as well as operation and maintenance costs of an efficient distribution company. The energy charge is adjusted every six months to reflect the changes in the spot market price for electricity. The distribution charge and service charge are approved by SIGET every five years and have two adjustments: (1) an annual adjustment considering the inflation variation and (2) an automatic adjustment in April, July and October, provided that the change in the adjusted value exceeds the value in effect by at least 10%.

The distribution tariff for all five distribution companies in El Salvador was reset on December 4, 2007. The approved tariff schedule is valid for five years (2008-2012). One outcome of the tariff reset was a significant reduction in the distribution value-added component of the tariff for AES CAESS and CLESA. On March 28, 2008, after negotiations with SIGET and the El Salvador Presidential House, a revised tariff schedule was enacted. It came into force on April 1, 2008. The negotiated tariff schedule included a higher technical losses index than originally recognized by SIGET. This permits the companies to recover an adequate portion of their technical losses through billing. The new tariffs improved distribution revenues by around 9% compared to the rates set on December 4, 2007. As a result of this negotiation and the enactment of the new rate schedule, AES agreed to withdraw its appeal recourse before the El Salvador Supreme Court, which was introduced on December 11, 2007.

As expected, SIGET approved new regulations for Service Connection and Reconnection charges, which came into force on November 3, 2008. The charges underwent a reduction of about 20% on average for these activities. In addition, there are also Quality of Service Regulations contained in SIGET resolution 192-E-2004, which require that distribution companies comply with certain U.S. Technical Product Standards, Technical Service Standards and Commercial Service Standards. The Quality of Service Standards became permanent in 2008, which means that they are now enforced to their full extent.

On October 23, 2008, SIGET enacted the bylaw for the Operation of the Transmission System and the Wholesale Market based on Generation Costs, which provides rules for the Independent System Operator, who is responsible for managing and operating the wholesale market for electricity. From 1996 until the passing of the bylaw, the wholesale market was governed by a price-offer system, whereby each generator submitted a daily price offer for its available generation (limited by a price cap) and the offer price determined dispatch. Under the new bylaw, each generating unit will have audited variable costs (generating costs), which will determine the economic dispatch merit order. The bylaw also provides for additional capacity payments to providers as determined by the regulator. The variable costs mechanism enabling legislation has been enacted, and it provides for a preparation and transition period before the regulations are in full force and effect which is scheduled to occur during the second half of 2010.

Currently, the Company does not face any regulatory action in El Salvador.

Nigeria. Nigeria s electricity sector consists of a power generation, transmission and distribution market, with current power production of approximately 6,000 MW of installed capacity, with the state-owned entity, Power Holding Company of Nigeria (PHCN), holding approximately 88% of the market share and thirty power generating companies holding the remaining 12%. The power generating companies, of which AES Nigeria Barges Ltd. (AESNB) is one, maintain long-term contracts with PHCN as the sole offtaker. All power transmission operations are carried out by PHCN, while two other distribution companies have been licensed.

The Nigerian Electricity Regulatory Commission (NC), an independent regulatory agency, which was established under the Electric Power Sector Reform Act in 2005, regulates the electricity sector and carries out general oversight functions in the Nigerian electricity sector, including the licensing of operators, setting of tariffs and industry standards for future electricity sector development. NC has asked AESNB to revalidate our generation license. As part of the revalidation exercise, NC is imposing certain conditions on AESNB which are in conflict with its PPA and which may result in additional costs for AESNB. AESNB is reviewing the terms of the new license and plans to negotiate its terms and conditions to make them more consistent with our existing PPA. At this time, it is not clear what the final outcome of these negotiations might be. Under the terms of the PPA, AESNB has a right to pass through any such additional cost and there is no cap. At present, we estimate that the additional costs, if any, due to the license will be about $1 million.

In March 2005, the Nigerian President signed the Electric Power Sector Reform Bill into law, enabling private companies to participate in transmission and distribution in addition to electricity generation that had previously been legalized. The government has separated PHCN into eleven distribution firms, six generating companies, and a transmission company, all of which plan to be privatized. Several problems, including union opposition, have delayed the privatization indefinitely. However, it is envisaged that after the privatization process, the power sector will transform into a fully liberalized market.

Panama. In 1998, as part of the privatization process, the Panamanian Government divided the Instituto de Recursos Hidráulicos y de Electrificación (IRHE) assets and operations into four generation companies, three distribution companies and one transmission company. Following a public auction, 51% of shares in each distribution company were sold by the Panamanian Government in September 1998. This was followed in November 1998 by the sale of 49% of shares in each of the three state-owned hydroelectric generation companies and 51% of shares in the main thermoelectric generation company. These sales were completed in 1999. As a result of the sales, AES acquired control and operation of two of the hydroelectric companies.

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The Panamanian Government retained control of *Empresa de Transmisión Eléctrica, S.A.* (ETESA), the state-owned transmission company, which operates and controls the National Interconnected System (NIS) of 230 Kilovolts (Kv) and certain 115Kv lines. Panama has one main interconnected system (the NIS) operated by ETESA. The transmission charges are reviewed and approved every four years by The National Authority of Public Services (ASEP); the current transmission tariffs are in effect until June 2013. The ASEP sets the framework for the tariff regime, determining transmission zones and rates applicable in the relevant zones and regulates power generation, transmission, interconnection and distribution activities in the electric power sector.

The National Dispatch Center (CND) is responsible for planning, supervising and controlling the integrated operation of the NIS and for ensuring its safe and reliable operation. The dispatch order is determined and planned by the CND, which dispatches electricity from generation plants based on lowest marginal cost. According to the Electricity Law, the order in which generators are dispatched must be based on maximizing efficient consumption of energy by minimizing the total cost of energy in the Panamanian power system.

Distribution companies are required to contract 100% of their annual power requirements (although they can self-generate up to 15% of their demand). Generators can enter into long-term PPAs with distributors or unregulated consumers. In addition, generators can enter into alternative supply contracts with each other. The terms and contents of PPAs are determined through a competitive bidding process and are governed by the Commercial Rules. AES Panama participated in the last Long Term Public Bid, EDEMET 01-08, for the supply of power and energy until the year 2022. The public bid was held on September 9, 2008 and AES Panama was contracted to provide 100MW at $92.95/MWh from the year 2012 until the year 2021 and 41 MW at $99.87/MWh from the year 2013 until the year 2022. AES Panama was already contracted to sell an average of 86% of firm capacity through 2018.

Under the Electricity Law, generation companies will not be granted new concessions if they would thereby account, directly or indirectly, for more than 25% of national electricity consumption. The percentage may be increased by the Panamanian Government where justified by competitive conditions subject to the approval of the ASEP. The percentage was increased to 40% by Executive Resolution No. 76 on October 19, 2005. This provision does not apply to licenses for thermal generation.

Besides the PPA market, generators may buy and sell energy in the spot market. Energy sold in the spot market corresponds to the hourly differences between the actual dispatch of energy by each generator and its contractual commitments to supply energy. The energy spot price is set by the order in which generators are dispatched. The CND ranks generators according to their variable cost (thermal) and the value of water (hydroelectric), starting with the lowest value, thereby establishing on an hourly basis the merit order in which generators will be dispatched the following day in order to meet expected demand. This price ranking system is intended to ensure that national demand will be satisfied by the lowest cost combination of available generating units in the country. A generator whose dispatched energy is greater than its contractual commitments to supply energy at any given time is a seller in the energy spot market; the reverse is true for a generator whose dispatched energy is less than its contractual commitments to supply energy. Generators and unregulated consumers can purchase energy in the energy spot market, while only generators can sell energy in the energy spot market.

Through Law 57 from October 2009, the Panamanian Government amended certain provisions of the Electricity Law. The most notable amendments were: (1) generators are now obligated to participate in public bids for PPAs, to the extent they have available firm capacity and energy, and failure to do so forfeits their ability to participate in the spot market; (2) ETESA, as opposed to the distribution companies, will now be the purchaser in charge of adjudicating PPA bids to the winning generators, subsequently assigning said PPAs to the corresponding distribution companies; and (3) the maximum fines which ASEP may impose for violations to the provisions of the Electricity Law are increased from $1 million to $20 million.

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North America

Mexico. Mexico has a single national electricity grid (referred to as the National Interconnected System), covering nearly all of Mexico s territory. The only exception is the Baja California peninsula which has its own separate electricity system. Article 27 of the Mexican Constitution reserves the generation, transmission, transformation, distribution and supply of electric power exclusively to the Mexican State for the purpose of providing a public service. The Federal Electricity Commission (CFE), by virtue of Article 1 of the Energy Law, is granted sole and exclusive responsibility for providing this public service as it relates to the supply, transmission and distribution of electric power.

In 1992, the Energy Law was amended to allow private parties to invest in certain activities in the Mexico electrical power market, under the assumption that self-supply generation of electric power is not considered a public service. These reforms allowed private parties to obtain permits from the Ministry of Energy for (i) generating power for self-supply; (ii) generating power through co-generation processes; (iii) generating power through independent production; (iv) small-scale production; and (v) importing and exporting electrical power. Beneficiaries holding any of the permits contemplated under the Energy Law are required to enter into PPAs with the CFE with regard to all surplus power produced. It is under this basis that AES s Mérida (Mérida) and TEG/TEP facilities operate. Mérida, a majority-owned 484 MW generation business, provides power exclusively to CFE under a long-term contract. TEG/TEP provides the majority of its output to two offtakers under long-term contracts, and can sell any excess or surplus energy produced to CFE at a predetermined day-ahead price.

United States. The U.S. wholesale electricity market consists of multiple distinct regional markets that are subject to both federal regulation, as implemented by the FERC, and regional regulation as defined by rules designed and implemented by the Independent System Operator (ISO). 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. The current regulatory framework in the U.S. is the result of a series of regulatory actions that have taken place over the past two decades, as well as numerous policies adopted by both the federal government and the individual states that encourage competition in wholesale and retail electricity markets.

The federal government, through regulations promulgated by FERC, has primary jurisdiction over wholesale electricity markets and transmission services. While there have been numerous federal statutes enacted during the past 30 years, including the Public Utility Regulatory Policy Act of 1978 (PURPA), the Energy Policy Act of 1992 (EPAct 1992) and the Energy Policy Act of 2005 (EPAct 2005), there are two fundamental regulatory initiatives implemented by FERC during that time frame that directly impact our U.S. businesses:

(a) FERC approval of market based rate authority beginning in 1986 for many providers of wholesale generation; and

(b) FERC issuance of Order #888 in 1996 mandating the functional separation of generation and transmission operations and requiring utilities to provide open access to their transmission systems.

Several of our generation businesses in the U.S. currently operate as Qualifying Facilities (QFs) as defined under 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 energy and facilities that would have been incurred by the purchasing utility if that utility had to provide its own generating capacity). EPAct 2005 later amended PURPA to eliminate the mandatory purchase obligation in certain markets, but did so only on a prospective basis. Cogeneration facilities and small power production facilities that meet certain criteria can be QFs. 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.

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Our non-QF generation businesses in the U.S. currently operate as Exempt Wholesale Generators (EWG s) as defined under EPAct 1992. These businesses were historically exempt from the Public Utility Holding Company Act of 1935 and are also exempt from the Public Utility Holding Company Act of 2005 (PUHCA 2005), and subject to FERC approval, have the right to sell power at market-based rates, either directly to the wholesale market or to a third-party offtaker such as a power marketer or utility/industrial customer. Under the Federal Power Act (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 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.

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

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

A brief description of the regulatory environment under which one of our larger generation businesses in the U.S. operates, Eastern Energy, is provided below:

Eastern Energy. AES, through its Eastern Energy subsidiary, currently operates four coal-fired generation plants with a combined total capacity of 1,268 MW located in the State of New York. The plants sell power directly to the New York Independent System Operator (NYISO), a FERC approved regional operator which manages the transmission system in New York and operates the state s wholesale electricity markets. NYISO is regulated as an electric utility by the FERC and has an Open Access Transmission Tariff on file that incorporates rates and conditions for use of the transmission system and a Market Services Tariff that describes the rules and conditions of use for the various markets.

The NYISO wholesale power markets are based on a combination of bilateral contracts, contracts for differences (CFDs) which financially settle relative to an agreed-upon index or floating price, and NYISO-administered day-ahead and real-time energy markets. The day-ahead market includes energy, regulation and operating reserves and is a financially binding commitment to produce or replace the products sold. The real-time market, which also offers energy, regulation and operating reserves, is a balancing market and is not a financially binding commitment but rather a best-effort standard. NYISO uses location-based marginal pricing (i.e., pricing for energy at a given location based on a market clearing price that takes into account physical limitations, generation and demand throughout the region) calculated at each node to account for congestion on the grid. Generators are paid the location marginal price at their node, while the end customer pays a zonal price that is the average of nodes within a zone. The market has a $1,000 per MWh cap on bids for energy. However, market rules also incorporate scarcity pricing mechanisms when the market is short of required operating reserves that can result in energy prices above $1,000 per MWh.

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In addition to our generation businesses, we also own IPL, a vertically integrated utility located in Indiana. A description of the regulatory environment under which IPL operates is provided below:

IPL. As a regulated electric utility, IPL is subject to regulation by the FERC and the Indiana Utility Regulatory Commission (IURC). As indicated below, the financial performance of IPL is directly impacted by the outcome of various regulatory proceedings before the IURC and FERC.

IPL is subject to regulation by the IURC with respect to the following: its services and facilities; the valuation of property; the construction, purchase or lease of electric generating facilities; the classification of accounts; rates of depreciation; retail rates and charges; the issuance of securities (other than evidences of indebtedness payable less than twelve months after the date of issue); the acquisition and sale of some public utility properties or securities; and certain other matters.

IPL s tariff rates for electric service to retail customers (basic rates and charges) are set and approved by the IURC after public hearings (general rate case). General rate cases, which have occurred at irregular intervals, include the participation of consumer advocacy groups and certain customers. The last general rate case for IPL was completed in 1995. In addition, pursuant to statute, the IURC is to conduct a periodic review of the basic rates and charges of all utilities at least once every four years, but the IURC has the authority to review the rates of any utility in its jurisdiction at any time it chooses. Such reviews have not been subject to public hearings.

The majority of IPL customers are served pursuant to retail tariffs that provide for the monthly billing or crediting to customers of increases or decreases, respectively, in the actual costs of fuel (including purchased power costs) consumed from estimated fuel costs embedded in basic rates, subject to certain restrictions on the level of operating income. These billing or crediting mechanisms are referred to as trackers . This is significant because fuel and purchased power costs represent a large and volatile portion of IPL s total costs. In addition, IPL s rate authority provides for a return on IPL s investment and recovery of the depreciation and operation and maintenance expenses associated with certain IURC-approved environmental investments. The trackers allow IPL to recover the cost of qualifying investments, including a return on investment, without the need for a general rate case.

IPL may apply to the IURC for a change in its fuel charge every three months to recover its estimated fuel costs, including the energy portion of purchased power costs, which may be above or below the levels included in its basic rates and charges. IPL must present evidence in each fuel adjustment charge (FAC) proceeding that it has made every reasonable effort to acquire fuel and generate or purchase power, or both, so as to provide electricity to its retail customers at the lowest cost reasonably possible.

Independent of the IURC s ability to review basic rates and charges, Indiana law requires electric utilities under the jurisdiction of the IURC to meet operating expense and income test requirements as a condition for approval of requested changes in the FAC. Additionally, customer refunds may result if IPL s rolling twelve month operating income, determined at quarterly measurement dates, exceeds IPL s authorized annual jurisdictional net operating income and there are not sufficient applicable cumulative net operating income deficiencies against which the excess rolling twelve month jurisdictional net operating income can be offset.

In IPL s six most recently approved FAC filings (FAC 81 through 86), the IURC found that IPL s rolling annual jurisdictional retail electric net operating income was lower than the authorized annual jurisdictional net operating income. FAC 86 includes the twelve months ended October 31, 2009. In IPL s FAC 76 through 80 filings, the IURC found that IPL s rolling annual jurisdictional retail electric net operating income was greater than the authorized annual jurisdictional net operating income. Because IPL has a cumulative net operating income deficiency, IPL has not been required to make customer refunds in their FAC proceedings.

In December 2007, IPL received a letter from the staff of the IURC requesting information relevant to the IURC s periodic review of IPL s basic rates and charges and IPL subsequently provided information to the staff. Since IPL s cumulative net operating income deficiency (described above) requires no customer refunds in the FAC process, the IURC staff was concerned that the higher-than-usual 2007 earnings may continue in the future. In response to the inquiry, IPL provided voluntary credits to its retail customers totaling $32 million. IPL recorded a $30 million deferred fuel regulatory liability in March 2008 and a $2 million deferred fuel regulatory liability in June 2008, with corresponding and respective reductions against revenues for these voluntary credits. All of these credits have been applied in the form of offsets against fuel charges that customers would have otherwise been billed during June 1, 2008 through February 28, 2009.

In September 2009, IPL received a letter from the staff of the IURC relevant to the IURC s periodic review of IPL s basic rates and charges which expressed concerns about IPL s level of earnings and invited IPL to provide additional information. The staff of the IURC has since requested additional information relative to IPL s level of earnings. In response, IPL provided information to the staff of the IURC. It is not possible to predict what impact, if any, the IURC s review may have on IPL.

IPL is a member of the Midwest Independent System Operator, Inc. (Midwest ISO). Midwest ISO serves as the third-party operator of IPL s transmission system and runs the day-ahead and real-time Energy Market and, beginning in January 2009, the Ancillary Services Market for its members.

IPL transferred functional control of its transmission facilities to the Midwest ISO and its transmission operations were integrated with those of the Midwest ISO. IPL s participation and authority to sell wholesale power at market-based rates are subject to the FERC jurisdiction. Transmission service over IPL s facilities is now provided through the Midwest ISO s tariff.

As a member of Midwest ISO market, IPL offers its generation and bids its demand into the market on an hourly basis. The Midwest ISO settles energy hourly offers and bids based on locational marginal prices, which is pricing for energy at a given location based on a market clearing price that takes into account physical limitations, generation and demand throughout the Midwest ISO region. The Midwest ISO evaluates the market participants energy offers and demand bids optimizing for energy products to economically and reliably dispatch the entire Midwest ISO system. The Company has certain regulatory assets on its balance sheet relating to IPL s participation in the Midwest ISO. The IURC has authorized IPL to recover the fuel portion of its costs from the Midwest ISO, to defer certain operational, administrative and other costs from the Midwest ISO and seek recovery in IPL s next basic rate case proceeding. Total Midwest ISO costs deferred by IPL as long-term regulatory assets were $62.8 million and $57.9 million as of December 31, 2009 and December 31, 2008, respectively. IPL will seek to recover the deferred costs in its next basic rate case proceeding; however, there can be no assurance that IPL would be successful in that regard.

Beginning in 2007, Midwest ISO transmission owners including IPL began to share the costs of transmission expansion projects with other transmission owners after such projects were approved by the Midwest ISO Board of Directors. Upon approval by the Midwest ISO Board of Directors, the transmission owners must make a good faith effort to build the projects. Costs allocated to IPL for the projects of other transmission owners are collected by the Midwest ISO per their tariff. We believe it is probable, but not certain, that IPL will ultimately be able to recover from its customers the money it pays to the Midwest ISO for its share of transmission expansion projects of other utilities, but such recovery is subject to IURC approval in IPL s next basic rate case. Therefore, such costs to date have been deferred as long term regulatory assets. To date, such costs have not been material to IPL, however, given the magnitude of the costs anticipated to enable conformance with renewables mandates in the Midwest ISO footprint, it is probable that such costs will become material in the next few years. Our current estimates are that IPL s share of such costs could be more than $50 million annually by 2020 and continue increasing after that.

In 2004, the IURC initiated an investigation to examine the overall effectiveness of Demand-Side Management (DSM) programs throughout the State of Indiana and to consider any alternatives to improve

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DSM performance statewide. On December 9, 2009, the IURC issued a Generic DSM Order that found that electric utilities subject to its jurisdiction must meet annual incremental jurisdictional energy sales reductions starting in 2010 at 0.3% and growing to 2% in 2019 (subject to certain adjustments). The IURC also found that all jurisdictional electric utilities have to participate in five initial, statewide core DSM programs, which will be administered by a Third Party Administrator. It is not possible at this time to predict the impact that the IURC s Generic DSM Order will have on IPL.

Prior to the issuance of the Generic DSM Order, IPL filed a petition seeking relief for substantive DSM programs. IPL proposed a DSM plan to be considered in two phases. The first phase (Phase I) sought recovery for traditional-type DSM programs, such as residential home weatherization and energy efficiency education programs, with additional offerings. The IURC issued an Order in February 2010 that approved the programs included in IPL s Phase I request. In addition to IPL s traditional recovery of the direct costs of the DSM program, the Order also included performance based incentives. The second phase (Phase II) sought recovery for Advanced DSM programs and was coincident with IPL s application for a smart grid funding grant from the Department of Energy. The Advanced DSM programs included an Advanced Metering Infrastructure communication backbone as well as two-way meters and home area network devices for certain of IPL s customers. In February 2010, the IURC issued an Order that approved IPL s Phase II program, but denied IPL s request to timely recover its expenditures. Instead, IPL would need to seek recovery of the costs incurred under its Phase II program during its next basic rate case proceeding. In light of these recent IURC Orders and the $20 million Smart Grid Investment Grant that IPL is currently negotiating (discussed below), IPL is still evaluating its DSM program and what the financial impacts will be.

The American Recovery and Reinvestment Act of 2009 was enacted into law in February 2009. The American Recovery and Reinvestment Act of 2009 includes various provisions that fund the development of the electric power industry at the federal and state level. These provisions include, but are not limited to, improving energy efficiency and reliability; electricity delivery (including smart grid technology); energy research and development; renewable energy; and demand response management. In August 2009, IPL submitted an application for a Smart Grid Investment Grant for $20 million to provide its customers with tools to help them more efficiently use electricity and also to upgrade its delivery system infrastructure. In October 2009, the U.S. Department of Energy notified IPL that its application had been selected for award negotiations. The U.S. Department of Energy s Office of Electricity Delivery and Energy Reliability conducted a briefing for all selectees in November 2009. Negotiations with the U.S. Department of Energy to finalize the award continue. It is unclear at this time what the tax impacts of this grant may be. IPL s project is part of our DSM plan (discussed above). IPL is evaluating the impact these recent IURC DSM Orders may have on its smart grid investment grant.

Europe, Middle East & Asia

Bulgaria. Bulgaria has been an EU member since January 1, 2007. The country s electricity sector is compliant with the EU s Electricity and Gas Directives. Bulgaria has an independent State Water and Energy Regulatory Commission (SWERC) which is mainly responsible for licensing energy products, compliance with the EU electricity and gas market rules and creating secondary renewable energy legislation. The sector is vertically unbundled with legal separation of generation, transmission and distribution into different operating entities. The market is fully liberalized with all customers now qualifying as eligible customers and free to contract for supply.

The Bulgarian market is a combination of a regulated market, a competitive market based on bilateral contracts and a balancing market, with the former dominating over the latter.

The National Electricity Company (NEK) is the Bulgarian public provider which owns, maintains and operates the 14,610 km high voltage (110Kv and above) transmission network through its 100% owned subsidiary Electricity System Operator (ESO). ESO is the system operator for dispatch control of the network. NEK also owns the biggest hydro-electric and pump storage generation facilities in Bulgaria.

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NEK does not operate in the consumer retail market. It purchases energy from producers and sells it to electricity distribution companies (all of which have been privatized) and large industrial consumers. It also exports electricity. Currently NEK is the sole company in Bulgaria licensed to export electricity. In addition, NEK purchases electricity under long-term PPAs with Thermal Power Plant Maritza East 2 and Thermal Power Plant Maritza East 3 (neither plant is owned by AES). Also, it will be purchasing electricity from renewable energy producers and combined heat and power plants at specified preferential prices.

NEK s role also includes the purchase of electricity from generators and its resale to distributor/supply companies and high-voltage customers. NEK s purchase and resale prices of electricity are determined by SWERC.

Power production from NEK s hydro-power plants and pump storage hydro-power plants falls within its function of a public provider. These plants are integrated in NEK s structure and no separate prices are set for them.

The distribution sector has been fully privatized, the country s seven distribution companies being bundled into three regional groups. In 2004, these groups were sold to the Czech State Electricity Company (CEZ) in Western Bulgaria, the Austrian EVN AG in Southern Bulgaria, and E.On Energia AG in North Eastern Bulgaria. As of January 1, 2007, the distribution companies have been separated into distribution grid operators and end suppliers.

The transmission network is well developed, with over 14,000 km of lines and a significant interconnection to neighboring countries, including Romania, Turkey, Greece, Macedonia and Serbia. The transmission system remains under NEK s ownership. However, in compliance with EU legislation NEK has spun off transmission operations (i.e. system operation, balancing market administration and systems operation and maintenance) to ESO. Regulated third-party access is provided for.

Following EU s renewable energy goals, Bulgaria developed a national long-term program to incentivize the use of renewable energy sources until 2015 and a Renewable Energy Law. The latter allocates a priority status for use of the distribution system and grid interconnection to generators of energy from alternative/renewable sources as well as guaranteed take-off of their output. As a national target, 16% of the total national energy consumption must come from renewable sources of generation by 2020.

China. In 2005, the National Development and Reform Commission (NDRC) released interim regulations governing on-grid tariffs, along with two other regulations governing transmission and retail tariffs. Pursuant to the interim regulations, the on-grid tariffs shall be appraised and ratified by the pricing authorities by reference to the economic life of power generation projects and determined in accordance with the principle of allowing IPPs to cover reasonable costs and to obtain reasonable returns. Such costs were defined to be the average costs in the industry and reasonable returns will be calculated on the basis of the interest rate of China s long-term Treasury bond plus certain percentage points. In addition to the foregoing tariff-setting mechanism, China s central government also issued a tariff adjustment policy allowing the on-grid tariffs to be pegged to the fuel price in the case of significant fluctuations in fuel price. Seventy percent of the increase in fuel costs may be passed through in the tariff. The tariffs of coal-fired facilities in China were increased in 2005, 2006 and 2008 pursuant to this policy to alleviate the escalation of fuel price; however, such adjustments were obtained from the regulatory authorities only after a time lag and fell short of compensating all businesses for coal price increases in recent years. There was no catch up tariff adjustment in 2009 pursuant to the foregoing policy.

Pursuant to the *Renewable Energy Law of China*, which came into effect on January 1, 2006, renewable resources such as wind, solar, biomass, geo-thermal, and hydro enjoy unrestricted generation and dispatch, and local grid interconnection is mandated to such plants. To implement the Renewable Energy Law, on August 2, 2007, various central government agencies jointly issued the *Temporary Measures for Dispatching Electricity Generated by Energy Conservation Projects*. Under this regulation, power plants are categorized into various groups and each group will, under certain circumstances, enjoy priority dispatch over the subsequent groups. The

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first group are renewable energy power plants, namely wind, hydro, solar, biomass, tidal-wave, geo-thermal and landfill gas power plants that satisfy certain environmental standards. The second group is nuclear power plants. The third group is power plants using modern coal which includes co-generation power plants, and power plants utilizing residual heat, residual gas, coal-gangue (or waste coal) and coal mine methane. The last three groups are natural gas, conventional coal and oil-fired power plants. As a result, power plants using renewable resources will enjoy priority dispatch over power plants using fossil fuels. This is in line with the requirement that renewable energy power plants will enjoy unrestricted generation and dispatch under the Renewable Energy Law, as well as the Chinese government s policy objective to encourage comprehensive utilization of resources in an energy-efficient and environmental-friendly manner.

In 2007, the Chinese government issued a number of rules and procedures that govern the shutdown of small coal or oil-fired power plants. The types of plants to be shut down include: (i) power plants with a capacity under 50 MW; (ii) power plants with a capacity of up to 100 MW which are over 20 years old; (iii) power plants with a capacity of up to 200 MW whose equipment has reached the end of its useful life; and (iv) power plants that have coal consumption rates that are higher than either 10% above the applicable provincial average or 15% above the national average. The shutdown procedures have been set in place to ensure that certain smaller power plants are appropriately shutdown and replaced by larger and more efficient power plants. The purpose of such rules and regulations is again in accord with China s policy to achieve energy conservation and emissions reductions. The Hefei business, in which AES held a 70% interest, was shut down pursuant to this policy. A termination agreement with the offtaker was reached and executed on March 30, 2008 and the Hefei business received a termination payment in the amount of $39 million on March 31, 2008. AES has received its shareholder s residual value in the Hefei business and the liquidation process of the Hefei business is expected to be completed by the end of February 2010.

On July 20, 2009, NDRC issued the *Circular on Refining the Policy for On-Grid Pricing of Wind Power* (NDRC Price 2009 No. 1906), which introduces a benchmark system for on-grid tariffs for wind power replacing the existing public bidding and concession model for wind projects. The circular provides that on-grid tariffs for onshore wind power projects approved from August 1, 2009 onwards are fixed using a centrally controlled price determination mechanism, while on-grid tariffs for offshore wind projects will be determined separately. Under the circular, China s onshore area is divided into four different types of wind-power resource regions, and different prices are set for each of these regions ranging from 0.51 yuan/kWh (US cent 7.5/kWh) for wind power in regions with the best wind resources, such as Inner Mongolia, to 0.61 yuan/kWh (US cent 8.9/kWh) for regions with the worst wind resources. According to NDRC, the legislation s intent is to standardize the wind power price regulation and promote healthy and sustainable development of the wind-power industry. Currently, we do not expect that this newly issued circular will have a material adverse impact on our wind power businesses in China.

Czech Republic. The electricity industry in the Czech Republic is dominated by three vertically integrated companies (CEZ, E.ON and PRE) that both supply and distribute power. CEZ, which owns approximately 70% of the installed capacity, produced approximately 73% of the Czech Republic s energy in 2007. Electricity distribution is also dominated by these three entities: CEZ (62%); E.ON (25%); and PRE (13%). There are 22 generators with installed capacity of over 50 MW and 25 generators with installed capacities between 5-50 MW, none of which have a market share greater than 3%. In accordance with EU directives regarding market liberalization, all customers are able to select their energy supplier.

Since August 2007, the Prague Energy Exchange has been trading energy in the form of base load and peak load on a monthly, quarterly and annual basis. The majority of electricity is, however, still traded on a bilateral basis between generators and distributors, independent traders (there are six major active traders plus more than 20 smaller traders in the market) and also between generators and final customers. In February 2008, a day-ahead spot market was incorporated into the Energy Exchange as existed in Slovakia. As of March 2009, the Prague Energy Exchange will also include Hungary trades. AES Bohemia s electricity, steam, water and compressed air output is governed under bilateral contracts with industrial and municipal customers in the surrounding area.

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European Union. European Union (EU) member states are required to implement EU legislation, although there is a degree of disparity as to how such legislation is implemented and the pace of implementation in the respective member states. EU legislation covers a range of topics which impact the energy sector, including market liberalization and environmental legislation. The Company has subsidiaries which operate existing generation businesses in a number of countries which are member states of the EU, including the Czech Republic, Hungary, the Netherlands, Spain and the United Kingdom. The Company also has subsidiaries which are in the process of constructing a generation plant in Bulgaria. Bulgaria became a member state of the EU as of January 1, 2007.

The principles of market liberalization in the EU electricity and gas markets were introduced under the Electricity and Gas Directives. In 2005, the European Commission (the Commission), the legislative and administrative body of the EU, launched a sector-wide inquiry into the European gas and electricity markets. In the context of the electricity market, the inquiry has to date focused on identifying issues related to price formation in the electricity wholesale markets and the role of long-term agreements as a possible barrier to entry with a view to improving the competitive situation. In January 2007, the Commission published a proposal for a new common energy policy for Europe. In November 2008, the Commission published a non-binding second Strategic Energy Review aimed at developing the concept of a common European Energy Policy. It focused mainly on security of supply and infrastructure development. The Strategic Energy Review proposed reviews of the Gas Storage Directive in 2010 and an update of the Oil Stocks Directives.

In October 2008, Energy Ministers reached political agreement on the Third Liberalization Package, which includes five pieces of legislation, Electricity and Gas Directives, Electricity and Gas Regulations and a Regulation creating a new Agency for the Coordination of Energy Regulators, which will have limited powers to deal with cross-border interconnectors and related issues. This legislation was formally adopted in August 2009 and must be implemented at national level by March 2011. Further legislative efforts at the EU level focused instead on the Climate Change Package. This package consists of three directives (Carbon Capture & Storage, an amended EU Emissions Trading Scheme (ETS), and a revised Renewables Directive). The ETS and Renewable Directives have now been adopted and should enter into force at national level in 2010. The main objectives of the Climate Change Package are usually referred to as the 20-20-20 goals:

- A 20% reduction in EU GHG emissions by 2020, as compared with 1990 levels, or 30% if other developed nations agree to take similar action by 2020;
- The ETS caps will deliver 21% GHG reduction by 2020 compared to 2005 levels, distribution will be skewed to favor lower GDP member states, and auctioning may be phased in for some member states power sectors;
- 20% increase in energy efficiency; and
- Minimum compulsory 10% target for renewable energy by 2020.

Progress in implementation of the directives referred to above varies from member state to member state. AES generation businesses in each member state will be required to comply with the relevant measures taken to implement the directives. See Environmental and Land Use Regulations Air Emissions below, for a description of these directives.

Hungary. The Hungarian market has one main interconnected system. The state-owned electricity wholesaler, MVM, is the dominant exporter, importer and wholesaler of electricity. MVM s affiliated company, MAVIR, is the Hungarian transmission system operator. Currently, Hungary is dependent on energy imports (mainly from Russia) since domestic production only partially covers consumption. Magyar Energia Hivatal (MEH), is the government entity responsible for regulation of the electricity industry in Hungary.

The adoption of the Electricity Act by Hungary in 2007, which became effective January 1, 2008, was the final legislative step to implement a fully liberalized electricity market. By virtue of the Electricity Act, all

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customers are eligible to choose their electricity supplier. In the competitive market, generators sell capacity to wholesale traders, distribution companies, other generators, electricity traders and eligible customers at an unregulated price.

Shortly before its accession to the EU, the Hungarian government notified the Commission of arrangements concerning compensation to the state-owned electricity wholesaler, MVM. The Commission decided to open a formal investigation in 2005 to determine whether or not any government subsidies were provided by MVM to its suppliers which were incompatible with the common market. In June 2008, the Commission reached its decision that the PPAs, including AES Tisza s PPA, contain elements of illegal state aid. The decision requires Hungary to terminate the PPAs within six months of the June 2008 publication of the decision, and to recover the alleged illegal state aid from the generators within ten months of publication. AES Tisza is challenging the Commission s decision in the Court of First Instance of the European Communities. Referring to the Commission s decision, Hungary adopted act number LXX of 2008 which terminates all long-term PPAs in Hungary, including AES Tisza s PPA, as of December 31, 2008, and requires generators to repay the alleged illegal state aid that was allegedly received by the generators through the PPAs, and provides for the possibility to offset stranded costs of the generators from the repayable state aid. Depending on the outcome of these events, there could be a material impact on the Company.

At the end of 2006 and for all of 2007, the Hungarian government reintroduced administrative pricing for all electricity generators, overriding PPA pricing, including the pricing in AES Tisza s PPA. In January 2007, AES Summit Generation Limited, a holding company associated with AES Tisza s operations in Hungary, and AES Tisza notified the Hungarian government of a dispute concerning its acts and omissions related to AES substantial investments in Hungary in connection with the reintroduction of the administrative pricing for Hungarian electricity generators. In conjunction with this, AES Summit and AES Tisza have commenced International Centre for Settlement of Investment Disputes (ICSID) arbitration proceedings against Hungary under the Energy Charter Treaty in connection with Hungary s reintroduction of the administrative pricing for Hungarian electricity generators. In the meantime, pursuant to the new Electricity Act in force from January 1, 2008, administrative pricing for electricity generators was subsequently abolished.

Hungary, pursuant to act number LXVII of 2008 introduced a special tax to be levied on energy companies including companies such as AES Tisza. The rate of the special tax is 8% and it is valid for two years, i.e., 2009 and 2010.

India. India s power sector is regulated by the Central Electricity Regulatory Commission (CERC) at the national level and respective State Electricity Regulatory Commissions (SERCs) at the state level. CERC is responsible for regulating interstate generation and central transmission, while intrastate generation, distribution and transmission are regulated by SERCs.

In 2003, the Government of India enacted the Electricity Act of 2003 (the Electricity Act) to establish a framework for a multi-seller-multi-buyer model for the electricity industry and introduced significant changes in India s electricity sector. In accordance with the Electricity Act, the Government of India came out with the National Electricity Policy in February 2005 and in January 2006 published the National Tariff Policy. The policies established deadlines to implement different provisions of the Electricity Act. However, the pace of actual implementation of the reform process is contingent on the respective state governments and SERCs, as electricity is a concurrent subject in India s constitution.

Under the Electricity Act, there is no license required to set up generation plants and generators are allowed to sell to state utilities, traders, and open access consumers. The access to consumers is subject to regulatory provisions on transmission corridor availability and payment of cross subsidy surcharge. Under the National Tariff Policy, sales since the end of 2006 from new IPP s to distribution utilities are required to be on a competitive bidding basis. Two power exchanges have received licenses from CERC and have started operations in the past year. However, the volume of power trading on the power exchanges is short term and small, as the bulk of power is still traded through long-term bilateral contracts.

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Kazakhstan. Under the present regulatory structure, the power generation and supply sector in Kazakhstan is mainly regulated by the Ministry of Energy and Mineral Resources (the Ministry), the Agency for Protection of Competition (the AZK), the Agency for Regulation of Natural Monopolies (the Regulator) and the Agency for Construction and Housing services (the Housing Agency). The Housing Agency is a newly established state body responsible for state policy in heat generation, distribution and supply as well as low-voltage electricity distribution. Each of the above-mentioned state bodies has the necessary authority for the supervision of the Kazakhstan power industry. However, continuous changes in the law result in certain contradictions between different laws and regulations. This in turn results in uncertainty in the regulatory environment for the power sector.

Kazakhstan has a wholesale electricity market and regional retail markets, where generators, electricity trading companies and customers are free to sign contracts with some restrictions imposed by laws. The electricity market has a functioning centralized trading system but contractual arrangements prevail. State-owned entities and natural monopolies are obligated to buy power through tenders and centralized trading. The wholesale transmission grid is owned by the state-owned company KEGOC, JSC, which also acts as the system operator. The government has a plan to introduce a real-time balancing market in the near future.

In 2009, the Kazakhstan government set upper price limits for thirteen groups of power plants for the seven-year period of 2009-2015 to prevent power price hikes in case of power shortages and to help attract investment. The power plant grouping was determined by the Ministry based on the plant type, equipment, fuel and distance from coal mines. The Ministry proposed to the government the level of price caps for each group based on the previous year s actual prices and level of investment required. The Ministry may propose additional annual adjustments to price caps to reflect inflation and investment requirements within any group. In cases where such price ceiling is too low to support investment into a particular project, a power generation company may apply for an individual investment tariff. The Ministry and the Regulator have rights jointly to approve the investment programs, approve the investment tariffs and sign an investment contract with a power plant. The legislation envisages substantial fines for any failure to implement investment programs.

The price cap and individual investment tariff regime does not constitute a price guarantee and power plants should sell to customers at the market price but not higher than their group price cap or an individual investment tariff. Only exports of power and sale of ten percent of generation through a centralized trading system are exempt from this restriction. Power trading activities are restricted and power plants are allowed to conduct trading activities to provide electricity supply to its customers during emergency shutdowns.

The Regulator approves and regulates all tariffs for power transmission and distribution. Power trading companies which the AZK considers dominant entities must notify the Regulator of the proposed increase of their prices and the Regulator has the right to veto such proposed tariff increases. Further, the Regulator has the right to request a decrease in the applicable tariffs and/or request introduction of the fixed prices for those power trading companies with a prior record of anti-monopoly violations.

The AZK recognizes all AES power plants in Kazakhstan as dominant entities in power generation of the Eastern Kazakhstan and Pavlodar regions. In addition, AES Sogrinsk CHP and Shygys Energo Trade LLP, a retailing company managed by AES, are also considered by AZK to be dominant entities in power trading in the Eastern Kazakhstan region. These two businesses are required to notify the Regulator about any price increases in power resale in Eastern Kazakhstan. In December 2009, the Regulator turned down an application of Shygys Energo Trade to increase the retail tariff by 37% based on technical shortcomings in the application. As a result, the cost of power for Shygys Energo Trade appears to be 40% higher than its current retail tariff due to significant increase of all cost components (power and transmission) earlier approved by the Regulator for all generators and transmission companies for 2010. In addition, the local Governor is requiring AES hydro power plants to sell 100% of its generated electricity to Shygys Energo Trade which has lead to increased debt before AES generators. AES is vigorously challenging these actions and attempting to have Shygys Energo Trade s retail tariff increased effective January 1, 2010 and avoid losses for Shygys Energo Trade and its generators.

In separate but related proceedings, all AES power plants in Kazakhstan are contesting their designation as dominant.

Philippines. The Philippines have three major island grids Luzon, Visayas, and Mindanao. Luzon is the largest grid, accounting for 79% and 71%, respectively, of installed capacity and gross generation. The Luzon and Visayas grids are interconnected through undersea cables. In June 2001, the Philippines Congress issued the Electric Power Industry Reform Act of 2001 (EPIRA), aiming at liberalizing the electricity sector, and transforming it from a single-buyer model in which National Power Company (NPC) plays a dominant role in generation, transmission, and distribution, to a competitive market model, in which NPC is privatized and competition is introduced in generation and distribution.

The Energy Regulatory Commission (ERC) was created to be the governing body for the restructured power industry and to promote competition, encourage market development, ensure customer choice and penalize abuse of market power. As part of its role, the ERC regulates the rates charged by transmission and distribution companies and as such approves cost recovery of contracts between generators and distribution companies.

The Power Sector Assets and Liabilities Management Corporation (PSALM) was created in July 2001 to manage the sale, disposition and privatization of the NPC generation assets. As of 2009, PSALM has sold 3,952 MW of NPC generating assets (including the sale of the 660 MW Masinloc plant to AES), and is in the process of selling additional generation assets representing approximately 246 MW of capacity.

EPIRA mandated PSALM to select and appoint qualified entities called Independent Power Producer Administrators (IPPA) to administer and manage the energy output that has been contracted by NPC with IPPs. PSALM initially appointed three independent trading teams to act as IPPA for these contracts, but it has now completed the process for the selling of 2,145 MW of contracted capacity. The additional sale of 1,200 MW of contracted capacity is underway.

The Wholesale Electricity Spot Market (WESM) started commercial operation in the Luzon grid in June 2006 with the primary objective of establishing a competitive, efficient, transparent, and reliable spot market for electricity. The market is organized around both bilateral contracts and a mandatory pool and spot market with the spot market consisting of an hour-ahead market (ex-ante) and a real-time (ex-post) market. Each generating unit submits hourly bids. The dispatch is arranged by the lowest to highest bid price and the spot price is set by the marginal price of the last dispatched unit following the merit order. Since AES is a merchant generator and does not have any take-or-pay power purchase agreements, the WESM provides a secondary market for AES electricity. It also provides a source of electricity from which AES can buy electricity to meet its contractual obligations when the plant outages.

Spain. Spain is a member of the EU and as such the Spanish Government has been taking steps to liberalize the country s electricity sector in accordance with EU directives. Since January 1, 2003, all customers have been eligible to choose their electricity supplier.

AES currently operates and holds a 71% ownership interest in a 1,199 MW natural gas-fired plant located in Cartagena on the southeast coast of Spain. The plant sells energy into the Pan-Iberian electricity market (MIBEL). The MIBEL market was created in January 2004 when Spain and Portugal signed a formal agreement. This new market allows generators in the two countries to sell their electricity on both sides of Spanish-Portuguese border as one single market. OMEL, Spain s energy market operator and Portugal s equivalent, OMIP, exchanged stakes in April 2006, and were re-organized such that an electricity forwards market was created in Lisbon and a spot market was created in Madrid.

The main transmission company, Red Eléctrica de España (REE) owns 99% of the 400 kV grid and 98% of the 220 kV network. The law has been changed to ensure that REE will become the sole transmission company in Spain. REE also operates as system operator (TSO) and is responsible for technical management of the system and for monitoring transmission. Under the country s energy infrastructure plan, REE plans to invest in strengthening the mainland grid, connecting new plants and improving interconnection throughout the country. In due course, AES Cartagena entered into an agreement with REE for the construction of the interconnection facilities. The use of such facilities is the subject of another standard regulated contract stating the specific terms and conditions of access.

In September 2002, the Spanish Cabinet approved a 10-year energy plan which focuses on meeting the country s future energy requirements. The plan also reflects reliance on renewable energy sources and cogeneration. The Spanish electricity system has seen a steady increase in the new generation capacity from renewable energy sources for many years, particularly as a result of attractive feed-in tariffs (approved by Royal Decree 661/207). Solar PV installed capacity is said to be in the region of 3.5 GW. The increase in renewable energy generation capacity supported by generous feed-in tariffs has led to major changes in the regulations with the aim of reducing the total cost of the feed-in tariffs for the Spanish electricity system. Partly as a result of that and also as a result of the tariff deficit already accumulated, Royal Decree-Law 6/2009 has introduced new measures that affect AES Cartagena. The main one is the creation of a new obligation on AES Cartagena (and certain other generation companies) to pay for a portion of the cost of providing a social subsidy to groups of economically vulnerable electricity consumers. Liability, under the AES Cartagena Energy Agreement, for this cost is currently the subject of a dispute with the Energy Manager, which has been referred to arbitration.

For the years 2008 and 2009, the number of emissions required to be surrendered by AES Cartagena under the ETS has been greater than the number of free emissions allocated to it. This is also expected in years 2010 to 2012. Liability, under the AES Cartagena Energy Agreement, for the cost of the shortfall in emissions is currently in dispute and is also the subject of the above-mentioned arbitration proceedings.

In February 2006, Spain introduced a law (Article 2 of Royal Decree Law 3/2006), with effect from March 2, 2006 that an amount equivalent to the value of the CO_2 emission allowances allocated free of charge to electricity generators will be netted from electricity sales proceeds obtained by Ordinary Regime electricity generation such as the Cartagena Plant. The parties obliged to pay these sums are the owners of generation facilities.

The Spanish Government implemented Orders (Order ITC/3315/2007, introduced on December 15, 2007, and Orders ITC/1721/2009 and ITC/1722/2009, introduced on June 26, 2009) which developed the principles set out in Article 2 and set the rules applicable for 2006, 2007 and January 1, 2008 June 30, 2009, respectively. The effect of these legislative provisions is that all owners of Ordinary Regime generation facilities in Spain are required to pay sums equivalent to the value of the CO_2 emissions allowances allocated free of charge for 2006, 2007, 2008 and the first six months of 2009. Liability, under the AES Cartagena Energy Agreement, for these costs is currently in dispute and is the subject of the above-mentioned arbitration proceedings. As for the periods after 2012, Directive 2003/87/EC establishes that power generation facilities will not be issued with allowances free of charge.

On December 23, 2002, Cadastral Law 48/2002 was enacted which created a new category of property identified as Special Real Estate. This, together with further legislative changes (i.e., Law 51/2002 and Law 16/2007), led to the Municipality of Cartagena increasing the relevant tax rate and the issuance by the Cadastral authorities of a new property value assessment on November 21, 2007 which resulted in an increase in the amount of Spanish property tax that is payable by AES Cartagena in respect of the plant. Liability, under the Energy Agreement, for this increase in tax is currently in dispute and is the subject of the above-mentioned arbitration proceedings.

Turkey. The wholesale generation and distribution market in Turkey is primarily a bilateral market dominated by state-owned entities. The state-owned Electricity Generation Company (EUAS) and its subsidiaries comprise approximately 24 GW of generation capacity and represent approximately 48% of the market. Private producers (with public off take) account for another 35%, and auto producers and merchant power plants the remaining 17%. The transmission network is owned and controlled by TEIAS, the State

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Transmission Company. TETAS, the Wholesale Trading Company, sets wholesale price based on average procurement costs from EUAS, auto-producers and Build Operate/Build Own Transfer/Transfer of Operating Rights producers. This wholesale price represents the buying price for TEDAS, the State Distribution Company. Under TEDAS, there were twenty regional distribution companies. In 2006, four of them were privatized and transferred to the new owners in 2008. Another five of them have been privatized in 2009 and are waiting approval for handover. In 2010 the Turkish Privatization Administration is planning to privatize all remaining regional distribution companies. There is also an hourly balancing spot market, with prices typically differing from hour to hour, but typically higher than those found through TETAS, which is growing and has a capacity of 50 Gigawatt hours (GWh) of daily trade. The automatic price mechanism which is meant to halt the government subsidization has been approved, and implementation commenced in July 2008. With this mechanism, all major cost items (foreign exchange, gas price increases, inflation, among others) are expected to be reflected in the tariff. As a result, mid-term market wholesale prices are expected to converge to the current spot market prices.

Distribution companies can procure 100% of their needs from TETAS and EUAS, but can also source up to 15% from other sources. Additionally, eligible customers, using greater than 100 MWh annually, can contract with the private wholesale companies and private power plants.

Retail electricity prices are calculated and proposed by the distribution companies and then approved by the electricity market regulatory authority, EMRA.

Turkey has introduced a renewable feed-in tariff that sets a floor for renewable generation (geothermal, wind and small scale hydro) for the first ten years of operation. The floor is between 0.050 and 0.055 per kWh and decreed by EMRA each year. AES Turkey hydro assets fall under the renewable feed-in tariffs.

The Turkish Government has also announced plans to privatize all the state-owned generation assets, other than certain large hydro-electric plants, in 2010.

Ukraine. The electricity sector in Ukraine is regulated by the National Energy Regulatory Commission (UNERC). Electricity costs to end users in Ukraine consist of three main components: (1) the wholesale market tariff is the price at which the distributor purchases energy on the wholesale market, (2) the distribution tariff covers the cost of transporting electricity over the distribution network, and (3) the supply tariff covers the cost of supplying electricity to an end user. The total cost permitted by the regulator under the distribution and supply tariff each year is referred to as the DVA. The distribution and supply tariffs for all distribution companies in Ukraine are established by the UNERC on an annual basis, at which time an operational expense allowance is adjusted for inflation and the tariff is adjusted for the amount of over-mandatory capital that was invested for the year and the amount of energy that was distributed. A change in the methodology was effected at the end of 2007 with respect to the treatment of wages and salaries such that the adjustment for inflation was replaced by an allowance based on the average industrial wage in the country.

In 2006, UNERC authorized two 25% increases in end user tariffs for residential customers. Since 2006 there have been no further changes in residential end-user tariffs. A moratorium on retail tariff increases was introduced by Presidential decree for non-residential customers, effective from December 1, 2008, which resulted in freezing of retail tariffs for the most part of 2009.The wholesale electricity market price increased by 18% in 2006, by 21% in 2007, 49% in 2008, and by 8.5% in 2009.

A comprehensive review of the distribution tariff methodology for the calculation including the rate of return on initial investment, operational expenses treatment, and definition and valuation of the rate base was expected to take place at the end of 2008. However, in late 2008, UNERC introduced minimal and short-term changes into the tariff methodology to be valid for 2009 and delayed a comprehensive review until 2010. Such short-term changes were implemented in 2009 and include (a) setting rates of return on initial investment at the level of 15% after tax for 2009, (b) wages and salaries treatment remaining as per the mechanism introduced in 2007, (c) operational expenses subject to indexation by inflation and (d) other operational expenses subject to adjustment based on actual expenses given reasonable substantiation. In late 2009, the comprehensive review was further delayed until 2011. For 2010, major elements of the 2009 tariff methodology were kept unchanged, including the 15% rate of return on investments. The delay is due to UNERC s intention to develop a new methodology applicable to all distribution and supply companies. In 2011, the comprehensive tariff methodology review is expected to take place addressing the issues of: (1) introduction of regulatory incentives to increase quality of service, (2) rate of return on investment, (3) rate base revaluation, and (4) operational expense allowance treatment.

In 2009 the Supreme Court of Ukraine took a preliminary position affecting distribution companies in the Ukraine including AES Kievoblenergo and AES Rivneoblenergo whereunder it required that certain network commercial losses of power that were previously treated as tax deductible could no longer be treated as such. This position, if maintained, may have a material effect on AES Kievoblenergo and AES Rivneoblenergo. The Company expects that the Supreme Court of Ukraine may clarify its position in 2010 and the proceedings in respect of AES Kievoblenergo and AES Rivneoblenergo are not likely to be finally resolved for another several years.

United Kingdom. AES Kilroot (Kilroot), is located in Northern Ireland, which is part of the United Kingdom, and is subject to regulation by the Northern Ireland Authority for Utility Regulation (NIAUR). Under the terms of the generating license granted to Kilroot, the NIAUR has the right to review and, subject to compliance with certain procedural steps and conditions, require the termination by 2010, at the earliest, of the long-term PPAs under which Kilroot currently supplies electricity to Northern Ireland Electricity plc (NIE) until 2024. One such condition is that at least 180 days notice of such termination be given.

On March 21, 2007, the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 was enacted, which provided for the introduction and regulation of a single wholesale electricity market for Northern Ireland and the Republic of Ireland that began operation in November of 2007. The legislation grants powers to the Department of Enterprise, Trade and Investment, or NIAER, for a period of two years to modify existing arrangements within the electricity market in Northern Ireland, including the power to modify existing licenses and/or require the amendment or termination of existing agreements or arrangements, to allow for the creation of a single wholesale electricity market. Modifications have been made to Kilroot s license and agreements to accomplish the objectives of the single market and to allow for the separation of NIE into constituent bodies and the extraction of the management of the transmission system (SONI) from NIE. These activities have been completed with reasonably minimal impact and with the creation of guarantees for Kilroot from NIE upon the long-term PPAs being transferred from NIE to NIE Energy Limited.

Revenues from the new market include a regulated capacity and an energy payment based on the system marginal price. Bidding principles restrict bids to short run marginal cost. Total annual capacity payments are calculated as the product of the annualized fixed cost of a best new entrant peaking plant multiplied by the capacity required to meet the security standard. This accumulated capacity is then distributed on the basis of plant availability.

Despite the new market mechanisms, Kilroot has continued to operate under its existing PPA which is able to subsist within the single wholesale market, although operating dispatch instructions are now a function of the new market inputs and system constraints and no longer the exclusive decision of NIE. While the PPAs are in place, Kilroot (a coal-fired plant), is neutral with respect to the cost of fuel as this is passed through to its PPA counterparty as an element of the payments made to Kilroot in respect of its availability. Although no PPAs were able to subsist, the NIAUR sought to invoke the introduction of the single electricity market (SEM) as a rationale for the early termination of the long-term PPAs between Kilroot and NIE Energy Limited. Kilroot challenged by way of judicial review proceedings the determination of NIAUR that the introduction of the SEM constituted requisite arrangements to allow such early termination. The hearing took place in May 2008 and found in favor of the NIAUR. On November 25, 2009, the NIAUR published a Consultation Paper on Relevant Considerations in Relation to the Possible Cancellation of Generating Unit Agreements in Northern Ireland which is relevant to various long-term PPAs in Northern Ireland including those at Kilroot. This consultation closed on January 27, 2010 and the paper states that it has been published by the NIAUR in order to set out and seek views on its initial thoughts on the type of issues and factors the NIAUR believes will or should inform the decision as to whether or not it should exercise its early cancellation power at the earliest opportunity. Although this power would grant the ability to the NIAUR to terminate the long-term PPAs from 2010 provided certain procedural steps and conditions are complied with, the current expectation is that due to the value of the CO_2 allowances (that passes through to the consumer while Kilroot is under contract), the likely earliest date that cancellation would be invoked is after 2012 (when free allowances are due to cease). If the PPAs were to be cancelled post-2012, Kilroot would then become a merchant plant and would operate under the gross mandatory pool operated in the SEM. The effect of this on the Kilroot business would then depend largely on the relative costs of coal and gas. Kilroot would continue to receive capacity payments under the SEM (although at a lower rate than the availability payments under the PPAs). If the price of coal was high relative to that of gas, this could have a material adverse impact for the Kilroot business. Conversely, if the price of coal was relatively low to that of gas, Kilroot could find this to be financially advantageous compared to the position under the existing PPAs.

Environmental and Land Use Regulations

Overview. The Company is subject to various international, national, state and local environmental and land use laws and regulations. These laws and regulations primarily relate to discharges into the air and air quality, discharge of effluents into water and the use of water, waste disposal, remediation, noise pollution, contamination at current or former facilities or waste disposal sites, wetlands preservation and endangered species. Many of the countries in which the Company does business also have laws and regulations relating to the siting, construction, permitting, ownership, operation, modification, repair and decommissioning of, and power sales from, such assets. In addition, international projects funded by the International Finance Corporation, the private sector lending arm of the World Bank, or many other international lenders, are subject to World Bank environmental standards or similar standards, which tend to be more stringent than local country standards. The Company often has used advanced environmental technologies in order to minimize environmental impacts, including circulating fluidized bed (CFB) coal technologies, flue gas desulphurization technologies, selective catalytic reduction technologies and advanced gas turbines.

Environmental laws and regulations affecting electric power generation facilities are complex, change frequently and have become more stringent over time. The Company has incurred and will continue to incur capital costs and other expenditures to comply with environmental laws and regulations. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Expenditures in this Form 10-K for more detail. If these regulations change or the enforcement of these regulations becomes more rigorous, the Company and its subsidiaries may be required to make significant capital or other expenditures to comply. There can be no assurance that the businesses operated by the subsidiaries of the Company would be able to recover any of these compliance costs from their counterparties or customers such that the Company s consolidated results of operations, financial condition and cash flows would not be materially adversely affected.

Various licenses, permits and approvals are required for our operations. Failure to comply with permits or approvals, or with environmental laws, can result in fines, penalties, capital expenditures, interruptions or changes to our operations. While the Company has at times been out of compliance with environmental laws and regulations, past non-compliance has not had a material adverse effect on our business, financial condition or results of operations. However, certain subsidiaries of the Company are subject to litigation or regulatory action relating to environmental permits or approvals. See Item 3. Legal Proceedings in this Form 10-K for more detail with respect to environmental litigation and regulatory action, including a revocation and reapproval of a new environmental permit for the Campiche project and a Notice of Violation (NOV) issued by the U.S. Environmental Protection Agency against IPL concerning new source review and prevention of significant deficiency issues under the U.S. Clean Air Act.

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Greenhouse Gas Laws, Protocols and Regulations. In 2009, the Company s subsidiaries operated electric power generation businesses which had total approximate direct CO_2 emissions of 74.2 million metric tonnes, approximately 39.7 million metric tonnes of which were emitted in the United States (both figures ownership adjusted). The Company uses CO_2 emission estimation methodologies supported by the The Greenhouse Gas Protocol reporting standard on GHG emissions. For existing power generation plants, CO_2 emissions are either obtained directly from plant continuous emission monitoring systems or calculated from actual fuel heat inputs and fuel type CO_2 emission factors. The following is an overview of both the regulations and laws that currently apply to our businesses and those that may be imposed over the next few years. Such regulations and laws could have a material adverse effect on the electric power generation businesses of the Company s subsidiaries and on the Company s consolidated results of operations, financial condition and cash flows. Certain of the Company s subsidiaries are developing and implementing GHG Emissions Reduction Projects to reduce GHG emissions and to generate GHG emissions reductions credits or offsets for use by the Company and/or for sale. There is no guarantee that these projects will be successful or that future regulatory programs will recognize such GHG emissions reduction credits or offsets. Further, the Company does not expect the amount of any such GHG emission reductions credits or offsets to be material to its consolidated results of operations, financial condition and cash flows.

International

In July 2003, the European Community Directive 2003/87/EC on Greenhouse Gas Emission Allowance Trading was created, which requires member states to limit emissions of CO_2 from large industrial sources within their countries. To do so, member states are required to implement EC-approved national allocation plans (NAPs). Under the NAPs, member states are responsible for allocating limited CO_2 allowances within their borders. Directive 2003/87/EC does not dictate how these allocations are to be made, and NAPs that have been submitted thus far have varied their allocation methodologies. For these and other reasons, uncertainty remains with respect to the implementation of the European Union Emissions Trading System (EU ETS) that commenced in January 2005. The European Union has announced that it intends to keep the EU ETS in place after 2012, even if the Kyoto Protocol is not extended or replaced by another agreement. The Company s subsidiaries operate seven electric power generation facilities, and another subsidiary has one under construction, within six member states which have adopted NAPs to implement Directive 2003/87/EC. Based on its current analyses, the Company does not expect that achieving and maintaining compliance with the NAPs to which its subsidiaries are subject will have a material impact on its consolidated operations or results. In particular, the risk and benefit associated with achieving compliance with applicable NAPs at several facilities of the Company s subsidiaries are not the responsibility of the Company s subsidiaries as they are subject to contractual provisions that transfer the costs associated with compliance to contract counterparties. However, one such contract counterparty, GDF-Suez, is currently disputing these provisions with AES Energia Cartagena S.R.L. In connection with this dispute or any similar dispute that might arise with other contract counterparties, there can be no assurance that the Company and/or the relevant subsidiary would prevail, or that the cost and administrative burden associated with any such dispute will not be significant. Certain Company subsidiaries will, however, bear some or all of the risk and benefit associated with compliance with applicable NAPs at certain facilities. Based upon anticipated operations, CO_2 emission allowance allocations, and the costs to acquire offsets and emission allowances for compliance purposes, the Company has not to-date incurred material costs to comply with Directive 2003/87/EC and applicable NAPs, however, there can be no guarantees that compliance will not have a material adverse effect on our business in future periods.

Legislative efforts at the EU have produced a Climate Change Package. This package consists of three directives Carbon Capture & Storage, an amended EU ETS and a revised Renewables Directive. The amended EU ETS and Renewable Directives have now been adopted and should enter into force at the national level in 2010. The main objectives of the Climate Change Package are usually referred to as the 20-20-20 goals:

A 20% reduction in EU GHG emissions by 2020, as compared with 1990 levels, or 30% if other developed nations agree to take similar action by 2020;

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The amended EU ETS caps will deliver 21% GHG reduction by 2020 compared to 2005 levels, distribution will be skewed to favor lower GDP member states, and auctioning may be phased in for some member states power sectors;

20% increase in energy efficiency; and

Minimum compulsory 10% target for renewable energy by 2020.

Progress in implementation of the directives referred to above varies from member state to member state. AES generation businesses in each member state will be required to comply with the relevant measures taken to implement the directives.

On February 16, 2005, the Kyoto Protocol became effective. The Kyoto Protocol requires the industrialized countries that have ratified it to significantly reduce their GHG emissions, including CO_2. The vast majority of developing countries which have ratified the Kyoto Protocol have no GHG reduction requirements, including many of the countires in which the Company s subsidiaries operate. In addition, of the 29 countries in which the Company s subsidiaries currently operate, all but one the United States (including Puerto Rico) have ratified the Kyoto Protocol. While we have developed and are implementing certain GHG Emissions Reduction Projects under the Clean Development and Joint Implementation Mechanisms of the Kyoto Protocol, there is no guarantee that we will be successful in developing these. To date, compliance with the Kyoto Protocol and EU ETS has not had a material adverse effect on the Company s consolidated results of operations, financial condition and cash flows. In December 2009, the annual United Nations conference of the parties to the Kyoto Protocol (called COP 15) was held in Copenhagen, Denmark to focus on establishing an international agreement or framework to succeed the Kyoto Protocol when it expires at the end of 2012. COP 15 did not result in any legally binding successor agreement to the Kyoto Protocol, but countries did agree to continue to work towards a successor international agreement on GHG reductions by the next annual conference. Countries also agreed to submit non-binding emission targets and climate change plans by January 31, 2010, although many countries have not yet submitted such targets or plans. The United States did submit such a non-binding target of reducing GHG emissions by 17% from 2005 levels by 2020. At present, the Company cannot predict whether compliance with the Kyoto Protocol or any successor agreements will have a material adverse effect on the Company s consolidated results of operations, financial condition and cash flows in future periods.

Even though it has been announced that the EU ETS will remain in place even if the Kyoto Protocol expires in 2012, there remains significant uncertainty with respect to the implementation of NAPs post-2012. The EU has indicated that a portion of the emission allowances given to member states will need to be auctioned under the NAPs and the Company cannot predict with any certainty if compliance with such programs will have a material adverse effect on its consolidated operations or results.

Countries in Latin America and Asia in which subsidiaries of the Company operate may also choose to adopt regulations that directly or indirectly regulate GHG emissions from coal plants. For example, in April 2008 a Chilean law, was enacted that requires a percentage of all new power purchase contracts held after August 31, 2007 be supplied by renewable sources. The Company s subsidiary has developed a plan for complying with the law. See Regulatory Matters Latin America Chile. Another example is in China. One of the ways that China has chosen to address its stated goals of energy conservation and CO_2 emissions reduction is by putting regulations and procedures in place that govern the shut down of certain small coal and oil-fired power plants and encourage replacement with larger more efficient power plants. The Hefei project, formerly operated by subsidiaries of the Company in China, was shut down pursuant to these regulations. A termination agreement with the Hefei offtaker was executed on March 30, 2008 and a subsidiary of the Company received a termination payment in the amount of $39 million on March 31, 2008. See Regulatory Matters Europe, Asia & Middle East China. Although the Company does not currently believe that laws and regulations pertaining to GHG emissions that have been adopted to date in countries in Latin America and Asia in which subsidiaries of the Company operate will have a material adverse effect on the Company s consolidated financial condition or results of operations, the Company cannot predict with any certainty if future laws and regulations in these countries regarding CO_2 emissions will have a material adverse effect on the Company s consolidated financial condition or results of operations.

United States Federal Legislation and Regulation

Currently, in the United States there are no Federal mandatory GHG emissions reduction programs (including CO_2) affecting the electric power generation facilities of the Company s subsidiaries, but there are numerous state programs and there is a possibility that federal GHG legislation will be enacted within the next several years. The U.S. House of Representatives passed federal GHG legislation in 2009, and such legislation may be considered by the full U.S. Senate. H.R. 2454, The American Clean Energy and Security Act of 2009 (ACESA), was passed by the U.S. House of Representatives on June 26, 2009, and contemplates a nationwide cap and trade program to reduce U.S. emission of CO_2 and other greenhouse gases starting in 2012. A summary of key features of ACESA is set forth below:

- A planned target to reduce by 2020 GHG emissions by 17% from 2005 levels and to reduce GHG emissions by 83% from 2005 levels by 2050.
- A requirement that certain GHG emitting companies, including most power generators, surrender on an annual basis one ton of CO_2 equivalent allowances or GHG offset credits for each ton of annual CO_2 equivalent emissions. Such companies would be required to meet allowance surrender requirements via the allocations of free allowances if available from the U.S. Environmental Protection Agency (EPA) or purchases in the open market at auctions if free allowances are not allocated, or otherwise.
- A mechanism under which the EPA would initially issue a capped and steadily declining number of tradable free emissions allowances to certain sections of affected industries, including certain generators and utilities in the electricity sector, with such free distribution of allowances to the electricity sector phasing out over a five year period from 2026 through 2030.
- A provision permitting up to two billion tons of GHG offset credits in the aggregate, if available, to be purchased annually by all emitters to satisfy the requirements above.
- A provision precluding the EPA from regulating GHG emissions under the existing provisions of the Clean Air Act (CAA).
- A temporary prohibition on the implementation of similar State or regional GHG cap and trade programs, with a six-year moratorium (2012 to 2017) on the implementation or enforcement of similar GHG emission caps.
- The establishment of a combined energy efficiency and renewable electricity standard (RES) that would require retail electric utilities to receive 6% of their power from renewable sources by 2012, with such requirement increasing to 20% by 2020. In certain circumstances, a portion of this requirement for renewable energy could be satisfied through measures intended to increase energy efficiency.

The Senate introduced similar legislation on September 30, 2009 with draft bill S. 1733, the Clean Energy Jobs and American Power Act (CEJAPA). CEJAPA contemplates a planned target to reduce by 2020 GHG emissions by 20% from 2005 levels and by 83% from 2005 levels by 2050. CEJAPA has been voted out of the Environment and Public Works Committee, but it has not been set for debate on the Senate floor. It is uncertain whether CEJAPA, in a modified form or its current form, will be voted upon by the full Senate or if the Senate will pursue less comprehensive legislation concerning GHG emissions.

At this time, if ACESA or CEJAPA were to be enacted into law, or some reconciled version of ACESA or CEJAPA were to be enacted, the impact on the Company s consolidated results of operations cannot be accurately predicted because of a number of uncertainties with respect to the specific terms and implementation of any such potential legislation, including, among other provisions:

- The number of free allowances that will be allocated to subsidiaries of the Company;

The cost to purchase allowances in an auction or on the open market, and the cost of purchasing GHG offset credits;

The extent to which our utility business (IPL) will be able to recover compliance costs from its customers;

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The benefits to our renewables businesses from the RES provision, if any;

The benefits to our GHG Emissions Reduction Projects from the potentially increased demand for GHG offset credits arising from GHG legislation, if any;

The benefits from the temporary moratorium on state or regional GHG cap and trade programs, if any; and

Whether such legislation would preempt EPA from regulating GHG emissions from electric generating units.

The EPA has proposed to regulate GHG emissions from motor vehicles in 2010 in accordance with the decision by the Supreme Court concluding that GHG emissions could be considered a pollutant under the CAA and subject to regulation under the CAA. Pursuant to that decision, the EPA has a duty to determine whether CO_2 emissions contribute to climate change or to provide some reasonable explanation why it will not exercise its authority. In order for the EPA to regulate CO_2 and other GHG emissions under Section 202 of the CAA, the EPA must determine that such emissions endanger public health and welfare under the CAA. On April 17, 2009, the EPA released proposed findings for comment which included a proposed finding that atmospheric concentrations of six greenhouse gases, including CO_2, endanger public health and welfare within the meaning of Section 202(a) of the CAA. On December 7, 2009, after review of the public comments to the proposed finding, the EPA issued the endangerment finding.

Also, in response to the Supreme Court s decision, on July 11, 2008, the EPA issued an Advanced Notice of Proposed Rulemaking to solicit public input on whether CO_2 emissions should be regulated from both mobile and stationary sources under Section 202 of the CAA. On September 28, 2009, the EPA proposed a rule to regulate GHG emissions from automobiles, a mobile source of emissions. If such rule is ultimately enacted with respect to a mobile source, one effect would be to subject stationary sources of GHG emissions (including power plants) to regulation under various sections of the CAA. The most important impact on stationary sources would be a requirement that all new sources of GHG emissions of over 250 tons per year, and existing sources planning physical changes that would increase their GHG emissions, obtain new source review permits from the EPA prior to construction. Such sources would be required to apply best available control technology to limit the emission of GHGs. On September 30, 2009, the EPA proposed a rule that would limit such regulation of stationary sources to those stationary sources emitting the CO_2 equivalent of over 25,000 tons per year of GHGs. The Company s coal and gas-fired U.S. power plants emit over 25,000 tons per year of GHGs and would fall within the scope of this proposed rule if they were to undertake physical changes that would increase their GHG emissions. In September of 2009, the EPA also finalized a rule mandating the widespread reporting and tracking of GHG emissions. Although this tracking and reporting rule does not mandate reductions in GHG emissions, data generated from its implementation may facilitate the further development of federal GHG policy, which may include mandatory GHG emissions limits.

United States State Legislation and Regulation

Ten northeastern states have entered into a memorandum of understanding under which the states coordinate to establish rules that require reductions in CO_2 emissions from power plant operations within those states. This initiative is called the Regional Greenhouse Gas Initiative (RGGI). A number of these states in which our subsidiaries have generating facilities, including Connecticut, Maryland, New York and New Jersey, have implemented rules to effectuate RGGI. RGGI, which became effective January 1, 2009, imposes a cap on baseline CO_2 emissions during the 2009 through 2014 period, and mandates a ten percent reduction in CO_2 emissions during the 2015 to 2019 period. RGGI establishes a cap-and-trade program whereby power plants will require a carbon allowance for each ton of CO_2. Unlike the previously implemented federal sulfur dioxide (SO_2) and NO_x cap-and-trade emissions programs, RGGI requires that CO_2 emitters acquire CO_2 allowances either from a RGGI auction or in the secondary emissions trading market, except for several small set-aside accounts for long term contracted plants and voluntary renewable energy. The auction rules include a minimum reserve price of $1.86 per allowance. This reserve price is subject to change. In addition, the auction platform and auction results are subject to review by an independent market monitoring firm. To date, six auctions have taken

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place with CO_2 clearing prices ranging from a high of $3.51 per allowance to a low of $2.05 per allowance. RGGI will continue to conduct quarterly auctions, and any entity can continue to buy or sell allowances in the secondary market.

The Company s Eastern Energy business is located in New York. Under the New York RGGI rule, each budgeted source of CO_2 emissions is required to surrender one CO_2 allowance for each CO_2 metric tonne emitted during a three-year compliance period. All fossil fuel powered generating facilities in New York that have a generating capacity of 25 or more MW are subject to the rule.

The Company s Thames business is located in Connecticut. The State of Connecticut passed legislation, effective July 1, 2007, which requires that the Connecticut Department of Environmental Protection develop necessary regulations to implement RGGI. The regulations adopted to implement RGGI include an auction of CO_2 emission allowances except for several set-aside accounts. AES Thames is eligible for a set-aside for the first compliance period, 2009-2011, which allows CO_2 allowances to be purchased at $2 per allowance in 2009, and $2 per allowance plus a consumer price indexing in years 2010 and 2011. Eligibility for the second compliance period, 2012-2014, is still to be determined.

The Company s Warrior Run business is located in Maryland. In April 2006, the Maryland General Assembly passed the Maryland Healthy Air Act which, among other thing things, required the State of Maryland to join RGGI. The Maryland Department of Environment (MDE) adopted regulations that require 100% of the allowances the State receives to be auctioned except for several small allowance set-aside accounts. The Maryland MDE regulations include a safety valve to control the economic impact of the CO_2 cap-and-trade program. If the auction closing price reaches $7, up to 50% of a year s allowances will be reserved for purchase by electric power generation facilities located within Maryland at $7 per allowance, regardless of auction prices.

The Company s Red Oak business is located in New Jersey. The State of New Jersey adopted the Global Warming Response Act in July 2007 which established goals for the reduction of GHG emissions in the State. In furtherance of these goals, in January 2008, additional state legislation authorized the New Jersey Department of Environmental Protection (NJDEP) to develop and adopt RGGI regulations and the NJDEP RGGI regulations became effective in 2008. The regulations adopted to implement RGGI include an auction of CO_2 emission allowances with procedures for the fixed-price sale of allowances to facilities with long-term power purchase contracts, directs allocation of allowances to cogeneration facilities meeting specified thermal efficiency criteria, and includes a CO_2 allowance set-aside designed to support the voluntary renewable energy market.

In 2009, of the approximately 39.7 million metric tonnes of CO_2 emitted in the United States by the businesses operated by our subsidiaries (ownership adjusted), approximately 9.7 million metric tonnes were emitted in U.S. states participating in RGGI. Over the past three years, such emissions averaged 11.1 million metric tonnes. We believe that due to the absence of allowance allocations, RGGI could have a material adverse impact on the Company s consolidated results of operations, financial condition and cash flows. While CO_2 emissions from businesses operated by subsidiaries of the Company are calculated globally in metric tonnes, RGGI allowances are denominated in short tons. (1 metric tonne equals 2,200 pounds and 1 short ton equals 2,000 pounds.) For forecasting purposes, the Company has modeled the impact of CO_2 compliance based on a three-year average of CO_2 emissions for its businesses that are subject to RGGI and that may not be able to pass through compliance costs. The model includes a conversion from metric tonnes to short tons as well as the impact of some market recovery by merchant plants and contractual and regulatory provisions. The model also utilizes a price of $2.05 per allowance under RGGI. The source of this allowance price estimate was the clearing price in the sixth and most recent RGGI allowance auction held in December 2009. Based on these assumptions, the Company estimates that the RGGI compliance costs could be approximately $17.5 million per year from 2010 through 2011, which is the last year of the first RGGI compliance period. Given the fact that the assumptions utilized in the model may prove to be incorrect, there is a significant risk that our actual compliance costs under RGGI will differ from our estimates by a material amount and that our model could underestimate our costs of compliance.

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The Company s Southland and Placerita businesses are located in California. On September 27, 2006, the Governor of California signed the Global Warming Solutions Act of 2006, also called Assembly Bill 32 (A.B. 32). A.B. 32 directs the California Air Resources Board to promulgate regulations that will require the reduction of CO_2 and other GHG emissions to 1990 levels by 2020. On November 24, 2009, the California Air Resources Board released its Proposed Draft Regulation (PDR). The PDR contemplates a cap and trade system that will be developed in coordination with the Western Climate Initiative (WCI) as detailed below. The PDR further contemplates a flexible compliance mechanism, with three-year compliance periods. The PDR also calls for the unrestricted banking of allowances (i.e., allowing allowances granted in a particular year to be surrendered for compliance in a subsequent year).

In February 2007, the governors of the Western U.S. states (Arizona, New Mexico, California, Washington and Oregon) established the WCI. The WCI has since been joined by two other states (Montana and Utah) and four Canadian provinces (British Columbia, Manitoba, Ontario, and Quebec). Participating states and provinces have agreed to cut GHG emissions to 15% below 2005 levels by 2020 and they are considering the implementation of a cap-and-trade program for the electricity industry to achieve this reduction. On September 23, 2008, the WCI issued its design recommendations for a cap-and-trade program which would apply to in-state electricity generators and the first jurisdictional deliverer of electricity into a WCI partner state. The WCI issued draft guidance on the creation of cap-and-trade allowance budgets on November 29, 2009. The draft guidance contemplates an eventual cap-and-trade program with flexible mechanisms, such as allowance banking and offsets. The final regulatory design of this program is not yet known.

The Company owns the utility IPL which is located in Indiana. On November 15, 2007, six Midwestern state governors (including the Governor of Indiana) and the premier of Manitoba signed the Midwestern Greenhouse Gas Reduction Accord (MGGRA) committing the participating states and province to reduce GHG emissions through the implementation of a cap-and-trade program. Three states (including Indiana) and the province of Ontario have signed as observers. The MGGRA Advisory Group has finalized a set of recommendations which are now being reviewed by the Governors of the relevant states. The recommendations are from the advisory group only, and have not been endorsed or approved by individual Governors, including the Governor of Indiana.

The Company owns a power generation facility in Hawaii. On June 30, 2007, the Governor of Hawaii signed Act 234 which sets a goal of reducing GHG emissions to at or below 1990 levels by January 1, 2020. Act 234 also established the Greenhouse Gas Emissions Reduction Task Force, which is tasked with developing measures to meet Hawaii s GHG emissions reduction goal. The Task Force filed a report to the Hawaii Legislature on December 30, 2009, strongly supporting the Hawaii Clean Energy Initiative, which calls for additional renewable energy development, increased energy efficiency, and incorporates already-enacted renewable portfolio standards. The Task Force also evaluated other mechanisms and concluded that a state-level cap-and-trade program is inappropriate due to the small size of Hawaii s economy.

At this time, other than the estimated impact of CO_2 compliance noted above for certain of its businesses that are subject to RGGI, the Company has not estimated the costs of compliance with other potential U.S. federal, state or regional CO_2 emissions reductions legislation or initiatives, such as A.B. 32, WCI, MGGRA and potential Hawaii regulations, due to the fact that these proposals are in the early stages of development and any final regulations or laws, if adopted, could vary drastically from current proposals. Although complete specific implementation measures for any federal regulations, A.B. 32, WCI, MGGRA and the Hawaiian regulations have yet to be finalized, if these GHG-related initiatives are finalized they will likely affect a number of the Company s U.S. subsidiaries unless they are preempted by federal GHG legislation. Any federal, state or regional legislation or regulations adopted in the U.S. that would require the reduction of GHG emissions could have a material adverse effect on the Company s consolidated results of operations, financial condition and cash flows.

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The possible impact of any future federal GHG legislation or regulations or any regional or state proposal will depend on various factors, including but not limited to:

- the geographic scope of legislation and/or regulation (e.g., federal, regional, state), which entities are subject to the legislation and/or regulation (e.g., electricity generators, load-serving entities, electricity deliverers, etc.), the enactment date of the legislation and/or regulation and the compliance deadlines set forth therein;

- the level of reductions of CO_2 being sought by the regulation and/or legislation (e.g., 10%, 20%, 50%, etc.) and the year selected as a baseline for determining the amount or percentage of mandated CO_2 reduction (e.g., 10% reduction from 1990 CO_2 emission levels, 20% reduction from 2000 CO_2 emission levels, etc.);

- the legislative structure (e.g., a CO_2 cap-and-trade program, a carbon tax, CO_2 emission limits, etc.);

- in any cap-and-trade program, the mechanism used to determine the price of emission allowances or offsets to be auctioned by designated governmental authorities or representatives;

- the price of offsets and emission allowances in the secondary market, including any price floors on the costs of offsets and emission allowances and price caps on the cost of offsets and emission allowances;

- the operation of and emissions from regulated units;

- the permissibility of using offsets to meet reduction requirements (e.g., type of offset projects allowed, the amount of offsets that can be used for compliance purposes, any geographic limitations regarding the origin or location of creditable offset projects) and the methods required to determine whether the offsets have resulted in reductions in GHG emissions and that those reductions are permanent (i.e., the verification method);

- whether the use of proceeds of any auction conducted by responsible governmental authorities is reinvested in developing new energy technologies, is used to offset any cost impact on certain energy consumers or is used to address issues unrelated to power;

- how the price of electricity is determined at the affected businesses, including whether the price includes any costs resulting from any new CO_2 legislation and the potential to transfer compliance costs pursuant to legislation, market or contract, to other parties;

- any impact on fuel demand and volatility that may affect the market clearing price for power;

- the effects of any legislation or regulation on the operation of power generation facilities that may in turn affect reliability;

- the availability and cost of carbon control technology;

whether legislation regulating GHG emissions will preclude EPA from regulating GHG emissions under the Clean Air Act or preempt private nuisance suits by third parties; and

any opportunities to change the use of fuel at the generation facilities of our subsidiaries or opportunities to increase efficiency.

Other U.S. Air Emission Regulations. In the U.S. the CAA and various state laws and regulations regulate emissions of air pollutants, including SO_2, NO_x, particulate matter (PM), and mercury. The applicable rules and the steps taken by the Company to comply with the rules are discussed in further detail below.

The U.S. EPA finalized two rules that are relevant to emissions of SO_2, NO_x, PM and mercury from our U.S. coal-fired power plants. The first rule, the Clean Air Interstate Rule (CAIR), was promulgated by the EPA on March 10, 2005, and required allowance surrender for SO_2 and NO_x emissions from existing power plants located in 28 eastern states and the District of Columbia. CAIR contemplated two implementation phases. The first phase was to begin in 2009 and 2010 for NO_x and SO_2, respectively. A second phase with additional allowance surrender obligations for both air emissions was to begin in 2015. To implement the required emission reductions for this rule, the states were to establish emission allowance-based cap-and-trade programs. CAIR was subsequently challenged in federal court and on July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit issued an opinion striking down CAIR. On December 23, 2008, in response to motions from the EPA and other petitioners, the Court issued an opinion and remanded the rule to the EPA without vacatur to enable the EPA to remedy CAIR s flaws in accordance with the Court s July opinion. The EPA plans to issue a proposed revision to CAIR in the spring of 2010. In the interim, until EPA finalizes a new rule to replace CAIR, the Company and a number of its subsidiaries are operating subject to the remanded CAIR.

The second rule, the Clean Air Mercury Rule (CAMR), was promulgated on March 15, 2005 and as proposed required reductions of mercury emissions from coal-fired power plants in two phases. However, on February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit ruled that CAMR as promulgated violated the CAA and vacated the rule. The EPA is obligated under the CAA, and the District of Columbia Circuit court ruling, to develop a rule requiring pollution controls for hazardous air pollutants (HAPs), including mercury, from coal and oil-fired power plants. EPA has entered into a consent decree under which it is obligated to propose the rule by October 2010 and to finalize the rule by November 2011. Under the CAA, compliance is required within three years of the effective date of the rule; however, the compliance period may be extended by the state permitting authorities (for one additional year) or through a determination by the President (for up to two additional years). The CAA requires EPA to establish maximum achievable control technology (MACT) standards for each hazardous air pollutant regulated under the CAA. MACT is defined as the emission limitation achieved by the best performing 12% of sources in the source category. While it is impossible to project what emission rate levels EPA may propose as MACT, the rule will likely require all coal-fired power plants to install acid gas scrubbers (wet or dry flue gas desulfurization technology) and/or some other type of mercury control technology, such as sorbent injection. Most of the Company s U.S. coal-fired plants have acid gas scrubbers or comparable control technologies, but it is possible that EPA regulations will require improvements to such control technologies at some of our plants.

While the exact impact and cost of CAIR, any new federal mercury rules, including MACT standards for HAPs and any related state proposals cannot be established until they are promulgated, and in the case of CAIR, until the states complete the process of assigning emission allowances to our affected facilities, there can be no assurance that any such new rules will not have a material adverse effect on the Company s business, financial conditions or results of operations.

The New York State Department of Environmental Conservation (NYSDEC) previously promulgated regulations requiring electric generators to reduce SO_2 emissions by 50% below current CAA standards. The SO_2 regulations began to be phased in beginning on January 1, 2006 with implementation to have been completed by January 1, 2008. These regulations also establish stringent NO_x reduction requirements during the non-ozone season, rather than just during the summertime ozone season. NYSDEC has announced that both programs will be phased out due to the federal CAIR programs.

On December 23, 2009, NYSDEC published a notice of proposed rulemaking requiring the application of Reasonably Available Control Technology (RACT) for reductions in NOx emissions from electric utility and industrial boilers, combustion turbines and internal combustion engines. The proposed regulations establish that sources subject to the new emission limits must demonstrate compliance by July 1, 2012. While the exact impact and cost of the RACT for NOx cannot be established until the rules are promulgated, there can be no assurance that the Company s business, financial conditions or results of operations would not be materially and adversely affected by any such mandatory reductions in emissions.

In 2005, the Company entered into a Consent Decree (the 2005 Consent Decree) with the State of New York, and New York State Electric and Gas Corporation (NYSEG) which resolves violations of CAA requirements alleged to have occurred at the Greenidge, Westover, Jennison and Hickling plants prior to the Company s acquisition of such plants. Under the terms of the 2005 Consent Decree, the Company is required to undertake projects to reduce emissions of certain air pollutants (Upgrade Projects) or to cease operations of certain electric generating units at the plants. The Company completed an Upgrade Project at Greenidge s Unit 4 in 2006 and a similar project at Westover s Unit 8 in 2008 and had ceased operations of the electric generating units at Hickling and Jennison. In accordance with the 2005 Consent Decree, the Company is required to provide notifications to the NYSDEC regarding the status of the Upgrade Projects and upon completion to propose new final emissions limits for NYSDEC s approval. The Company has received NYSDEC approval for proposed final emissions limits applicable to Greenidge s Unit 4 and the Company is considering a similar proposal for Westover Unit 8. In addition, the Consent Decree also required that the non-reheat units at Greenidge and Westover, Greenidge Unit 3 and Westover Unit 7, either undertake projects to reduce emissions of certain air pollutants, repower, or to cease operations of electric generation by December 31, 2009. Official retirement notices for both Units (Greenidge Unit 3 and Westover Unit 7) were provided to the New York State Public Service Commission and New York Independent System Operator in 2009. The units were officially retired as of December 31, 2009.

In July 1999, the EPA published the Regional Haze Rule to reduce haze and protect visibility in designated federal areas. On June 15, 2005, the EPA proposed amendments to the Regional Haze Rule that, among other things, set guidelines for determining when to require the installation of best available retrofit technology (BART) at older plants. The amendment to the Regional Haze Rule required states to consider the visibility impacts of the haze produced by an individual facility, in addition to other factors, when determining whether that facility must install potentially costly emissions controls. The Regional Haze Rule was further amended on October 6, 2006 when the EPA promulgated a rule allowing states to impose alternatives to BART, including emissions trading, if such alternatives were demonstrated to be more effective than BART. States were required to submit their regional haze state implementation plans (SIPs) to the EPA by December 2007, but only 13 states met this deadline. EPA has yet to approve any state s Regional Haze state implementation plan. The statute requires compliance within five years after EPA approves the relevant SIP.

Other International Air Emission Regulations. In Europe the Company is, and will continue to be, required to reduce air emissions from our facilities to comply with applicable EC Directives, including Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants (the LCPD), which sets emission limit values for NO_x, SO_2, and particulate matter for large-scale industrial combustion plants for all member states. Until June 2004, existing coal plants could opt-in or opt-out of the LCPD emissions standards. Those plants that opted out will be required to cease all operations by 2015 and may not operate for more than 20,000 hours after 2008. Those that opted-in, like the Company s AES Kilroot facility in the United Kingdom, must invest in abatement technology to achieve specific SO_2 reductions. Kilroot installed a new flue gas desulphurization system in the second quarter of 2009 in order to satisfy SO_2 reduction requirements. The Company s other coal plants in Europe are either exempt from the Directive due to their size or have opted-in but will not require any additional abatement technology to comply with the LCPD.

In Chile, a draft regulation has been published by the national environmental regulatory agency (CONAMA) that calls for limits on certain emissions from thermal power plants, such as NO_x, SO_2, metals and particulate matter. The draft regulation is currently undergoing a public hearing process under which interested parties can provide comments to CONAMA which will decide on possible further changes before the regulation is finalized and ultimately submitted to the President for approval. If such regulation were to be enacted in its current form, the Company s subsidiaries in Chile may need to acquire and install additional pollution control technologies over a period of three to four years. While the exact impact and cost of any such regulation cannot be determined until it is finalized, there can be no assurance that the Company s business, financial conditions or results of operations would not be materially or adversely affected by any such mandatory reductions in emissions.

Water Discharges. The Company s facilities are subject to a variety of rules governing water discharges. In particular the Company is subject to the U.S. Clean Water Act Section 316(b) rule regarding existing power plant cooling water intake structures issued by the EPA in 2005 (69 Fed. Reg. 41579, July 9, 2004) and the subsequent

Circuit Court of Appeals decision and Supreme Court decision regarding this rule. The rule as originally issued could affect 12 of the Company s U.S. power plants and the rule s requirements would be implemented via each plant s National Pollutant Discharge Elimination System (NPDES) water quality permit renewal process. These permits are usually processed by state water quality agencies. To protect fish and other aquatic organisms, the 2004 rule requires existing steam electric generating facilities to utilize the best technology available for cooling water intake structures. To comply, a steam electric generating facility must first prepare a Comprehensive Demonstration Study to assess the facility s effect on the local aquatic environment. Since each facility s design, location, existing control equipment and results of impact assessments must be taken into consideration, costs will likely vary. The timing of capital expenditures to achieve compliance with this rule will vary from site to site. On January 25, 2007, the United States Court of Appeals for the Second Circuit decision (Docket Nos. 04-6692 to 04-6699) vacated and remanded major parts of the 2004 rule back to the EPA. In November 2007, three industry petitioners sought review of the Second Circuit s decision by the U.S. Supreme Court and this review was granted by the U.S. Supreme Court in April 2008. In its April 2009 decision, the U.S. Supreme Court granted the EPA authority to use a cost-benefit analysis when setting technology-based requirements under Section 316(b) of the Clean Water Act and expressed no view on the remaining bases for the Second Circuit s remand. New draft 316(b) regulations are expected to be issued by EPA later this year, and until such regulations are final the EPA has instructed state regulatory agencies to use their best professional judgment in determining how to evaluate what constitutes best technology available for minimizing adverse environmental impacts from cooling water intake structures. Certain states in which the Company operates power generation facilities, such as New York, have been delegated authority and are moving forward with best technology available determinations in the absence of any final rule from the EPA. At present, the Company cannot predict the final requirements under Section 316(b) or whether compliance with the anticipated new 316(b) rule will have a material impact on our operations or results, but the Company expects that capital investments and/or modifications resulting from such requirements could be significant.

Waste Management. In the course of operations, the Company s facilities generate solid and liquid waste materials requiring eventual disposal or processing. With the exception of coal combustion byproducts (CCB), its wastes are not usually physically disposed of on our property, but are shipped off site for final disposal, treatment or recycling. CCB, which consists of bottom ash, fly ash and air pollution control wastes, is disposed of at some of our coal-fired power generation plant sites using engineered, permitted landfills. Waste materials generated at our electric power and distribution facilities include CCB, oil, scrap metal, rubbish, small quantities of industrial hazardous wastes such as spent solvents, tree and land clearing wastes and polychlorinated biphenyl (PCB) contaminated liquids and solids. The Company endeavors to ensure that all its solid and liquid wastes are disposed of in accordance with applicable national, regional, state and local regulations. On December 22, 2009, a dike at a coal ash containment area at the Tennessee Valley Authority s plant in Kingston, Tennessee failed and over 1 billion gallons of ash was released into adjacent waterways and properties. Following such incident, there has been heightened focus on the regulation of CCBs and EPA is expected to issue a proposed rule shortly regarding CCB storage and management. EPA is also evaluating whether CCB should be regulated as a hazardous waste under the Resource Conservation and Recovery Act (RCRA). If EPA promulgates a rule that deems CCB to be a hazardous waste under Subtitle C of the RCRA then ash disposal costs for the Company s U.S. coal plants would likely increase significantly. Also, many of the Company s U.S. coal plants currently sell CCB to third parties undertaking beneficial use projects in which the CCB is recycled, such as for use in concrete and other building materials. If CCB were deemed to be a hazardous waste under Subtitle C of the RCRA, it could pose a significant hurdle for companies that currently sell CCB as a raw material for beneficial use. Third parties are likely to be less willing or unable to continue using CCB in their products and the Company s U.S. coal plants may no longer be able to generate revenue from the sale of such CCB. While the exact impact and compliance cost associated with future regulations of CCB cannot be established until such regulations are promulgated, there can be no assurance that the Company s business, financial conditions or results of operations would not be materially and adversely affected by such regulations.

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ITEM 1A. RISK FACTORS

You should consider carefully the following risks, along with the other information contained in or incorporated by reference in this Form 10-K. Additional risks and uncertainties also may adversely affect our business and operations including those discussed in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations in this Form 10-K. If any of the following events actually occur, our business and financial results could be materially adversely affected.

Risks Associated with our Disclosure Controls and Internal Control over Financial Reporting

We recently completed the remediation of our material weaknesses in internal control over financial reporting. However, our disclosure controls and procedures may not be effective in future periods if our judgments prove incorrect or new material weaknesses are identified.

For each of the fiscal quarters since December 31, 2004 through September 30, 2008, our management reported material weaknesses in our internal control over financial reporting. A material weakness is a deficiency (within the meaning of the Public Company Accounting Oversight Board (PCAOB) Auditing Standard No. 5), or a combination of deficiencies, that adversely affects a company s ability to initiate, authorize, record, process, or report external financial data reliably in accordance with generally accepted accounting principles such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected. As a result of these material weaknesses, our management concluded that for each of the fiscal quarters since December 31, 2004 through September 30, 2008, we did not maintain effective internal control over financial reporting and concluded that our disclosure controls and procedures were not effective to provide reasonable assurance that financial information that we are required to disclose in our reports under the Exchange Act was recorded, processed, summarized and reported accurately.

To address these material weaknesses in our internal control over financial reporting, each time we prepared our annual and quarterly reports we performed additional analyses and other post-closing procedures. These additional procedures were costly, time consuming and required us to dedicate a significant amount of our resources, including the time and attention of our senior management, toward the correction of these problems. Nevertheless, even with these additional procedures, the material weaknesses in our internal control over financial reporting caused us to have errors in our financial statements and since 2003 we had to restate our annual financial statements six times to correct these errors.

The material weaknesses in our internal control over financial reporting also caused us to delay the filing of certain quarterly and annual reports with the SEC to dates that went beyond the deadline prescribed by the SEC s rules to file such reports. We did not timely file with the SEC our quarterly and annual reports for the year ended December 31, 2005, our quarterly reports for the second and third quarters of 2005, our annual report for the year ended December 31, 2006, and our quarterly report for the quarter ended March 31, 2007. Under SEC rules, failure to timely file these reports prohibited us for a period of twelve months from offering and selling our securities pursuant to our shelf registration statement on Form S-3, which impaired our ability to access the capital markets through the public sale of registered securities in a timely manner. The failure to file our annual and quarterly reports with the SEC in a timely fashion also resulted in covenant defaults under our senior secured credit facility and the indenture governing certain of our outstanding debt securities. Such defaults required us to obtain a waiver from the lenders under the senior secured credit facility; however the default under the indentures was cured upon the filing of the reports within the permitted grace period. In addition to these problems, the material weaknesses in internal controls, the restatements of our financial statements and the delay in the filing of our annual and quarterly reports exposed us to other risks including, but not limited to:

- litigation or an expansion of the SEC s informal inquiry into our restatements or the commencement of formal proceedings by the SEC or other regulatory authorities, which could require us to incur significant legal expenses and other costs or to pay damages, fines or other penalties;

- negative publicity;

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- ratings downgrades; or
- the loss or impairment of investor confidence in the Company.

Since December 31, 2008, our management has reported that all of our previously identified material weaknesses have been remediated and that our internal control over financial reporting and our disclosure controls have been effective. For a discussion of our internal control over financial reporting and our disclosure controls, see Item 9A. Controls and Procedures in this Form 10-K. In making their assessment about the effectiveness of our internal control over financial reporting and our disclosure controls and procedures, management had to make certain judgments and it is possible that any number of their judgments could prove to be incorrect and that our remediation efforts did not fully and completely cure the previously identified material weaknesses. There is also the possibility that there are other material weaknesses in our internal control that are unknown to us or that new material weaknesses may develop in the future. The existence of any material weakness in our internal control over financial reporting would subject us to all of the risks described above.

Furthermore, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, changes in accounting practice or policy, or that the degree of compliance with the revised policies or procedures deteriorates over time. Management, including our CEO and CFO, does not expect that our internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs.

Risks Related to our High Level of Indebtedness

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

As of December 31, 2009, we had approximately $19.9 billion of outstanding indebtedness on a consolidated basis. All outstanding borrowings under The AES Corporation s senior secured credit facility, our Second Priority Senior Secured Notes and certain other indebtedness are secured by certain of our assets, including the pledge of capital stock of many of The AES Corporation s directly-held subsidiaries. Most of the debt of The AES Corporation s subsidiaries is secured by substantially all of the assets of those subsidiaries. Since we have such a high level of debt, a substantial portion of cash flow from operations must be used to make payments on this debt. Furthermore, since a significant percentage of our assets are used to secure this debt, this reduces the amount of collateral that is available for future secured debt or credit support and reduces our flexibility in dealing with these secured assets. This high level of indebtedness and related security could have other important consequences to us and our investors, including:

- making it more difficult to satisfy debt service and other obligations at the holding company and/or individual subsidiaries;
- increasing the likelihood of a downgrade of our debt, which could cause future debt costs and/or payments to increase and consume an even greater portion of cash flow;
- increasing our vulnerability to general adverse economic and industry conditions;
- reducing the availability of cash flow to fund other corporate purposes and grow our business;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry;
- placing us at a competitive disadvantage to our competitors that are not as highly leveraged; and

limiting, along with the financial and other restrictive covenants relating to such indebtedness, among other things, our ability to borrow additional funds as needed or take advantage of business opportunities as they arise, pay cash dividends or repurchase common stock.

The agreements governing our indebtedness, including the indebtedness of our subsidiaries, limit, but do not prohibit the incurrence of additional indebtedness. To the extent we become more leveraged, the risks described above would increase. Further, our actual cash requirements in the future may be greater than expected. Accordingly, our cash flows may not be sufficient to repay at maturity all of the outstanding debt as it becomes due and, in that event, we may not be able to borrow money, sell assets, raise equity or otherwise raise funds on acceptable terms or at all to refinance our debt as it becomes due.

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

The AES Corporation is a holding company with no material assets other than the stock of its subsidiaries. All of The AES Corporation s revenue is generated through its subsidiaries. Accordingly, almost all of The AES Corporation s cash flow is generated by the operating activities of its subsidiaries. Therefore, The AES Corporation s ability to make payments on its indebtedness and to fund its other obligations is dependent not only on the ability of its subsidiaries to generate cash, but also on the ability of the subsidiaries to distribute cash to it in the form of dividends, fees, interest, loans or otherwise.

However, our subsidiaries face various restrictions in their ability to distribute cash to The AES Corporation. Most of the subsidiaries are obligated, pursuant to loan agreements, indentures or project financing arrangements, to satisfy certain restricted payment covenants or other conditions before they may make distributions to The AES Corporation. In addition, the payment of dividends or the making of loans, advances or other payments to The AES Corporation may be subject to other contractual, legal or regulatory restrictions. Business performance and local accounting and tax rules may limit the amount of retained earnings that may be distributed to us as a dividend. Subsidiaries in foreign countries may also be prevented from distributing funds to The AES Corporation as a result of foreign governments restricting the repatriation of funds or the conversion of currencies. Any right that The AES Corporation has to receive any assets of any of its subsidiaries upon any liquidation, dissolution, winding up, receivership, reorganization, bankruptcy, insolvency or similar proceedings (and the consequent right of the holders of The AES Corporation s indebtedness to participate in the distribution of, or to realize proceeds from, those assets) will be effectively subordinated to the claims of any such subsidiary s creditors (including trade creditors and holders of debt issued by such subsidiary).

The AES Corporation could receive less funds than it expects as a result of the current challenges facing the global and local economies, which could impact the performance of our businesses and their ability to distribute cash to The AES Corporation. For further discussion of the macroeconomic environment and its impact on our business, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Global Recession.

The AES Corporation s subsidiaries are separate and distinct legal entities and, unless they have expressly guaranteed any of The AES Corporation s indebtedness, have no obligation, contingent or otherwise, to pay any amounts due pursuant to such debt or to make any funds available whether by dividends, fees, loans or other payments. While some of The AES Corporation s subsidiaries guarantee its indebtedness under its senior secured credit facility and certain other indebtedness, none of its subsidiaries guarantee, or are otherwise obligated with respect to, its outstanding public debt securities.

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

We attempt to finance our domestic and foreign projects primarily under loan agreements and related documents which, except as noted below, require the loans to be repaid solely from the project s revenues and provide that the repayment of the loans (and interest thereon) is secured solely by the capital stock, physical assets, contracts and cash flow of that project subsidiary or affiliate. This type of financing is usually referred to

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as non-recourse debt or project financing. In some project financings, The AES Corporation has explicitly agreed to undertake certain limited obligations and contingent liabilities, most of which by their terms will only be effective or will be terminated upon the occurrence of future events. These obligations and liabilities take the form of guarantees, indemnities, letter of credit reimbursement agreements and agreements to pay, in certain circumstances, the project lenders or other parties.

As of December 31, 2009, we had approximately $19.9 billion of outstanding indebtedness on a consolidated basis, of which approximately $5.5 billion was recourse debt of The AES Corporation and approximately $14.4 billion was non-recourse debt. In addition, we have outstanding guarantees, letters of credit, and other credit support commitments which are further described in this Form 10-K in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity Parent Company Liquidity.

Some of our subsidiaries are currently in default with respect to all or a portion of their outstanding indebtedness. The total debt classified as current in our consolidated balance sheets related to such defaults was $612 million at December 31, 2009. While the lenders under our non-recourse project financings generally do not have direct recourse to The AES Corporation (other than to the extent of any credit support given by The AES Corporation), defaults thereunder can still have important consequences for The AES Corporation, including, without limitation:

- reducing The AES Corporation s receipt of subsidiary dividends, fees, interest payments, loans and other sources of cash since the project subsidiary will typically be prohibited from distributing cash to The AES Corporation during the pendency of any default;

- triggering The AES Corporation s obligation to make payments under any financial guarantee, letter of credit or other credit support which The AES Corporation has provided to or on behalf of such subsidiary;

- causing The AES Corporation to record a loss in the event the lender forecloses on the assets;

- triggering defaults in The AES Corporation s outstanding debt and trust preferred securities. For example, The AES Corporation s senior secured credit facility and outstanding senior notes include events of default for certain bankruptcy related events involving material subsidiaries. In addition, The AES Corporation s senior secured credit facility includes certain events of default relating to accelerations of outstanding debt of material subsidiaries; or

- the loss or impairment of investor confidence in the Company.

None of the projects that are currently in default are owned by subsidiaries that meet the applicable definition of materiality in The AES Corporation s senior secured credit facility or other debt agreements in order for such defaults to trigger an event of default or permit acceleration under such indebtedness. However, as a result of future write-down of assets, dispositions and other matters that affect our financial position and results of operations, it is possible that one or more of these subsidiaries could fall within the definition of a material subsidiary and thereby upon an acceleration of such subsidiary s debt, trigger an event of default and possible acceleration of the indebtedness under The AES Corporation s senior secured credit facility. The risk of such defaults may have increased as a result of the deteriorating global economy. For further discussion of these conditions, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Global Recession of this Form 10-K.

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Risks Associated with our Ability to Raise Needed Capital

The AES Corporation has significant cash requirements and limited sources of liquidity.

The AES Corporation requires cash primarily to fund:

principal repayments of debt;

interest and preferred dividends;

acquisitions;

construction and other project commitments;

other equity commitments, including business development investments;

taxes; and

Parent Company overhead costs.

The AES Corporation s principal sources of liquidity are:

dividends and other distributions from its subsidiaries;

proceeds from debt and equity financings at the Parent Company level; and

proceeds from asset sales.

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

While we believe that these sources will be adequate to meet our obligations at the Parent Company level for the foreseeable future, this belief is based on a number of material assumptions, including, without limitation, assumptions about our ability to access the capital or commercial lending markets, the operating and financial performance of our subsidiaries, exchange rates, our ability to sell assets, and the ability of our subsidiaries to pay dividends. Any number of assumptions could prove to be incorrect and therefore there can be no assurance that these sources will be available when needed or that our actual cash requirements will not be greater than expected. For example, in the current credit crisis, certain financial institutions have gone bankrupt. In the event that a bank who is party to our credit agreement or other facilities goes bankrupt or is otherwise unable to fund its commitments, we would need to replace that bank in our syndicate or risk a reduction in the size of the facility, which would reduce our liquidity. In addition, our cash flow may not be sufficient to repay at maturity the entire principal outstanding under our credit facilities and our debt securities and we may have to refinance such obligations. There can be no assurance that we will be successful in obtaining such refinancing and any of these events could have a material effect on us.

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

From time to time, we rely on access to capital markets as a source of liquidity for capital requirements not satisfied by operating cash flows. Our ability to arrange for financing on either a recourse or non-recourse basis and the costs of such capital are dependent on numerous factors, some of which are beyond our control, including:

- general economic and capital market conditions;
- the availability of bank credit;
- investor confidence;

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the financial condition, performance and prospects of The AES Corporation in general and/or that of any subsidiary requiring the financing as well as companies in our industry or similar financial circumstances; and

changes in tax and securities laws which are conducive to raising capital.

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

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

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

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

Part of our strategy is to grow our business by developing Generation and Utility businesses in less developed economies where the return on our investment may be greater than projects in more developed economies. Commercial lending institutions sometimes refuse to provide non-recourse project financing in certain less developed economies, and in these situations we have sought and will continue to seek direct or indirect (through credit support or guarantees) project financing from a limited number of multilateral or bilateral international financial institutions or agencies. As a precondition to making such project financing available, the lending institutions may also require governmental guarantees of certain project and sovereign related risks. There can be no assurance, however, that project financing from the international financial agencies or that governmental guarantees will be available when needed, and if they are not, we may have to abandon the project or invest more of our own funds which may not be in line with our investment objectives and would leave less funds for other projects. These risks have increased as a result of the recent credit crisis and the deteriorating global economy. For further discussion of these global economic conditions and their potential impact on the Company, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Global Recession.

External Risks Associated with Revenue and Earnings Volatility

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

Our exposure to currency exchange rate fluctuations results primarily from the translation exposure associated with the preparation of the Consolidated Financial Statements, as well as from transaction exposure associated with transactions in currencies other than an entity s functional currency. While the Consolidated Financial Statements are reported in U.S. Dollars, the financial statements of many of our subsidiaries outside the United States are prepared using the local currency as the functional currency and translated into U.S. Dollars by applying appropriate exchange rates. As a result, fluctuations in the exchange rate of the U.S. Dollar relative to

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the local currencies where our subsidiaries outside the United States report could cause significant fluctuations in our results. In addition, while our expenses with respect to foreign operations are generally denominated in the same currency as corresponding sales, we have transaction exposure to the extent receipts and expenditures are not denominated in the subsidiary s functional currency.

We also experience foreign transaction exposure to the extent monetary assets and liabilities, including debt, are in a different currency than the subsidiary s functional currency. Moreover, the costs of doing business abroad may increase as a result of adverse exchange rate fluctuations. Our financial position and results of operations have been affected by fluctuations in the value of a number of currencies, primarily the Brazilian real, Argentine peso, Chilean peso, Colombian peso and Philippine peso.

Our businesses may incur substantial costs and liabilities and be exposed to price volatility as a result of risks associated with the wholesale electricity markets, which could have a material adverse effect on our financial performance.

Some of our Generation businesses sell electricity in the wholesale spot markets in cases where they operate wholly or partially without long-term power sales agreements. Our Utility and Generation businesses may also buy electricity in the wholesale spot markets. As a result, we are exposed to the risks of rising and falling prices in those markets. The open market wholesale prices for electricity are very volatile and often reflect the fluctuating cost of coal, natural gas, or oil. Consequently, any changes in the supply and cost of coal, natural gas, and oil may impact the open market wholesale price of electricity.

Volatility in market prices for fuel and electricity may result from among other things:

- plant availability;
- competition;
- demand for energy commodities;
- electricity usage;
- seasonality;
- interest rate and foreign exchange rate fluctuation;
- availability and price of emission credits;
- input prices;
- hydrology and other weather conditions;
- illiquid markets;

transmission or transportation constraints or inefficiencies;

availability of competitively priced renewables sources;

available supplies of natural gas, crude oil and refined products, and coal;

generating unit performance;

natural disasters, terrorism, wars, embargoes and other catastrophic events;

energy, market and environmental regulation, legislation and policies;

geopolitical concerns affecting global supply of oil and natural gas; and

general economic conditions in areas where we operate which impact energy consumption.

The Company has faced gas curtailments in the past. For example, gas supply in the Argentine market is increasingly scarce and exports have been both taxed and curtailed. Gas supply curtailments can be exacerbated during the Argentine winter (May through September) when domestic demand for electricity experiences a seasonal increase. Since substantially all of the gas used in the Chilean power sector is currently imported from Argentina, gas curtailments can impact our Chilean operations through higher fuel costs and higher costs of purchased energy from the spot market. Our natural gas-fired plant in Southern Brazil, Uruguaiana, has also been impacted by limited fuel supply. Since 2004, Uruguaiana has had its gas supply interrupted from May to September. During the fourth quarter of 2007, the combination of gas curtailments and increases in the spot market price of energy triggered an impairment analysis of Uruguaiana s long-lived assets for recoverability. As a result of this impairment analysis, aggregate pre-tax impairment charges of $388 million were recognized in 2008 and 2007 which represents a full impairment of the fixed assets.

In addition, our business depends upon transmission facilities owned and operated by others. If transmission is disrupted or capacity is inadequate or unavailable, our ability to sell and deliver power may be limited, which may have a material adverse impact on our business.

We may not be adequately hedged against our exposure to changes in commodity prices or interest rates.

We routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity, fuel requirements and other commodities to lower our financial exposure related to commodity price fluctuations. As part of this strategy, we routinely utilize fixed-price forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges. We also enter into contracts which help us to hedge our interest rate exposure on variable debt. However, we may not cover the entire exposure of our assets or positions to market price (or interest rate) volatility, and the coverage will vary over time. Furthermore, the risk management procedures we have in place may not always be followed or may not work as planned. In particular, if prices of commodities (or interest rates) significantly deviate from historical prices or if the price volatility (or interest rates) or distribution of these changes deviates from historical norms, our risk management system may not protect us from significant losses. As a result, fluctuating commodity prices may negatively impact our financial results to the extent we have unhedged or inadequately hedged positions. In addition, certain types of economic hedging activities may not qualify for hedge accounting under GAAP, resulting in increased volatility in our net income. The Company may also suffer losses associated with basis risk which is the assumed relative correlation of performance between the intended hedge instrument and the targeted underlying exposure. Furthermore, there is a risk that the current parties to these arrangements may fail or are unable to perform their obligations under these arrangements.

Supplier and/or customer concentration may expose the Company to significant financial credit or performance risks.

We often rely on a single contracted supplier or a small number of suppliers for the provision of fuel, transportation of fuel and other services required for the operation of certain of our facilities. If these suppliers cannot perform, we would seek to meet our fuel requirements by purchasing fuel at market prices, exposing us to market price volatility and the risk that fuel and transportation may not be available during certain periods at any price.

At times, we rely on a single customer or a few customers to purchase all or a significant portion of a facility s output, in some cases under long-term agreements that account for a substantial percentage of the anticipated revenue from a given facility. We have also hedged a portion of our exposure to power price fluctuations through forward fixed price power sales. Counterparties to these agreements may breach or may be unable to perform their obligations. We may not be able to enter into replacement agreements on terms as favorable as our existing agreements, or at all. If we were unable to enter into replacement PPAs, these businesses may have to sell power at market prices.

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

The market pricing of our common stock has been volatile and may continue to be volatile in future periods.

The market price for our common stock has been volatile in the past, and the price of our common stock could fluctuate substantially in the future. Stock price movements on a quarter by quarter basis for the past two years are set forth in Item 5. Market Information of this Form 10-K. Factors that could affect the price of our common stock in the future include general conditions in our industry, in the power markets in which we participate and in the world, including environmental and economic developments, over which we have no control, as well as developments specific to us, including, risks that could result in revenue and earnings volatility as well as other risk factors described in this Item 1A. Risk Factors and those matters described in Item 7. Management s Discussion and Analysis.

Risks Associated with our Operations

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

A significant amount of our revenue is generated outside the United States and a significant portion of our international operations is conducted in developing countries. Part of our growth strategy is to expand our business in developing countries because the growth rates and the opportunity to implement operating improvements and achieve higher operating margins may be greater than those typically achievable in more developed countries. International operations, particularly the operation, financing and development of projects in developing countries, entail significant risks and uncertainties, including, without limitation:

- economic, social and political instability in any particular country or region;
- adverse changes in currency exchange rates;
- government restrictions on converting currencies or repatriating funds;
- unexpected changes in foreign laws and regulations or in trade, monetary or fiscal policies;
- high inflation and monetary fluctuations;
- restrictions on imports of coal, oil, gas or other raw materials required by our generation businesses to operate;
- threatened or consummated expropriation or nationalization of our assets by foreign governments;
- difficulties in hiring, training and retaining qualified personnel, particularly finance and accounting personnel with U.S. GAAP expertise;
- unwillingness of governments, government agencies, similar organizations or other counterparties to honor their contracts;

unwillingness of governments, government agencies, courts or similar bodies to enforce contracts that are economically advantageous to subsidiaries of the Company and economically unfavorable to counterparties, against such counterparties, whether such counterparties are governments or private parties;

inability to obtain access to fair and equitable political, regulatory, administrative and legal systems;

adverse changes in government tax policy;

difficulties in enforcing our contractual rights or enforcing judgments or obtaining a just result in local jurisdictions; and

potentially adverse tax consequences of operating in multiple jurisdictions.

Any of these factors, by itself or in combination with others, could materially and adversely affect our business, results of operations and financial condition. For example, partly in response to challenging business and political conditions in Kazakhstan, in 2008 we sold certain businesses in that country. As another example, in the second quarter of 2007, we sold our stake in EDC to Petróleos de Venezuela, S.A. (PDVSA), the state owned energy company in Venezuela after Venezuelan President Hugo Chavez threatened to expropriate the electricity business in Venezuela. In connection with the sale, we recognized an impairment charge of approximately $680 million. In addition, our Latin American operations experience volatility in revenues and gross margin which have caused and are expected to cause significant volatility in our results of operations and cash flows. The volatility is caused by regulatory and economic difficulties, political instability and currency devaluations being experienced in many of these countries. This volatility reduces the predictability and enhances the uncertainty associated with cash flows from these businesses.

The operation of power generation and distribution facilities involves significant risks that could adversely affect our financial results.

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

changes in the availability of our generation facilities or distribution systems due to increases in scheduled and unscheduled plant outages, equipment failure, failure of transmission systems labor disputes, disruptions in fuel supply, inability to comply with regulatory or permit requirements or catastrophic events such as fires, floods, storms, hurricanes, earthquakes, explosions, terrorist acts or other similar occurrences; and

changes in our operating cost structure including, but not limited to, increases in costs relating to: gas, coal, oil and other fuel; fuel transportation; purchased electricity; operations, maintenance and repair; environmental compliance, including the cost of purchasing emissions offsets and capital expenditures to install environmental emission equipment; transmission access; and insurance. Our businesses require reliable transportation sources (including related infrastructure such as roads, ports and rail), power sources and water sources to access and conduct operations. The availability and cost of this infrastructure affects capital and operating costs and levels of production and sales. Limitations, or interruptions in transportation including as a result of third parties intentionally or unintentionally disrupting the facilities of our subsidiaries, could impede their ability to produce electricity. This could have a material adverse effect on our businesses results of operations, financial condition and prospects.

In addition, a portion of our generation facilities were constructed many years ago. Older generating equipment may require significant capital expenditures for maintenance. This equipment is also likely to require periodic upgrading and improvement. Breakdown or failure of one of our operating facilities may prevent the facility from performing under applicable power sales agreements which, in certain situations, could result in termination of a power purchase or other agreement or incurring a liability for liquidated damages.

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

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

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

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

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

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

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

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

We may not be able to enter into long-term contracts, which reduce volatility in our results of operations. Even when we successfully enter into long-term contracts, our generation businesses are dependent on one or a limited number of customers and a limited number of fuel suppliers.

Many of our generation plants conduct business under long-term contracts. In these instances, we rely on power sales contracts with one or a limited number of customers for the majority of, and in some case all of, the relevant plant s output and revenues over the term of the power sales contract. The remaining terms of the power sales contracts range from 1 to 25 years. In many cases, we also limit our exposure to fluctuations in fuel prices by entering into long-term contracts for fuel with a limited number of suppliers. In these instances, the cash flows and results of operations are dependent on the continued ability of customers and suppliers to meet their obligations under the relevant power sales contract or fuel supply contract, respectively. Some of our long-term power sales agreements are at prices above current spot market prices and some of our long-term fuel supply contracts are at prices below current market prices. The loss of significant power sales contracts or fuel supply contracts, or the failure by any of the parties to such contracts that prevents us from fulfilling our obligations there under, could have a material adverse impact on our business, results of operations and financial condition. In addition, depending on market conditions and regulatory regimes, it may be difficult for us to secure long-term contracts, either where our current contracts are expiring or for new development projects. The inability to enter into long-term contracts could require many of our businesses to purchase inputs at market prices and sell electricity into spot markets. Because of the volatile nature of inputs and power prices, the inability to secure long-term contracts could generate increased volatility in our earnings and cash flows and could generate substantial losses during certain periods which could have a material impact on our business and results of operations.

We have sought to reduce counter party credit risk under our long-term contracts in part by entering into power sales contracts with utilities or other customers of strong credit quality and by obtaining guarantees from the sovereign government of the customer s obligations. However, many of our customers do not have, or have failed to maintain, an investment grade credit rating, and our Generation business can not always obtain government guarantees and if they do, the government does not always have an investment grade credit rating. We have also sought to reduce our credit risk by locating our plants in different geographic areas in order to mitigate the effects of regional economic downturns. However, there can be no assurance that our efforts to mitigate this risk will be successful. These risks have increased as a result of the deteriorating global economy. For further discussion of these global economic conditions and their potential impact on the Company, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Global Recession in this Form 10-K.

Competition is increasing and could adversely affect us.

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

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

Certain of our subsidiaries have defined benefit pension plans covering substantially all of their respective employees. Of the twenty five defined benefit plans, three are at U.S. subsidiaries and the remaining plans are at foreign subsidiaries. Pension costs are based upon a number of actuarial assumptions, including an expected long-term rate of return on pension plan assets, the expected life span of pension plan beneficiaries and the discount rate used to determine the present value of future pension obligations. Any of these assumptions could prove to be wrong, resulting in a shortfall of pension plan assets compared to pension obligations under the pension plan. The Company periodically evaluates the value of the pension plan assets to ensure that they will be sufficient to fund the respective pension obligations. The Company s exposure is mitigated due to the fact that the asset allocations in our largest plans are more heavily weighted to investments in fixed income securities that have not been as severely impacted by the global recession. Nevertheless, given the recent significant declines in financial markets, the value of these pension plan assets has declined and our future pension expense and funding obligations have increased. In addition, future downturns in the debt and/or equity markets, or the inaccuracy of any of our significant assumptions underlying the estimates of our subsidiaries pension plan obligations, could result in an increase in pension expense and future funding requirements, which may be material. Our subsidiaries who participate in these plans are responsible for satisfying the funding requirements required by law in their respective jurisdiction for any shortfall of pension plan assets compared to pension obligations under the pension plan. This may necessitate additional cash contributions to the pension plans that could adversely affect the Parent Company and our subsidiaries liquidity.

For additional information regarding the funding position of the Company s pension plans, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates Pension and Postretirement Obligations and Note 13 to our Consolidated Financial Statements included in this Form 10-K.

Our business is subject to substantial development uncertainties.

Certain of our subsidiaries and affiliates are in various stages of developing and constructing greenfield power plants, some but not all of which have signed long-term contracts or made similar arrangements for the sale of electricity. Successful completion depends upon overcoming substantial risks, including, but not limited to, risks relating to failures of siting, financing, construction, permitting, governmental approvals or the potential for termination of the power sales contract as a result of a failure to meet certain milestones. Timing of equipment purchases can also pose financial risks to the company. As part of our development process, we attempt to make purchases of equipment and/or materials as needed. However, from time to time, there may be excess demand for certain types of equipment with substantial delays between the time we place orders and receive delivery. In those instances, to avoid construction delays and costs associated with the inability to own and place such equipment and/or materials into service when needed in the construction process, we may place orders well in advance of deployment. In some cases, we may order such equipment and/or materials without yet having a specific project where the equipment and/or materials will be deployed, in anticipation that equipment and materials will be needed at the time of delivery. However, there is a risk that at the time of delivery, we are required to accept delivery and pay for such equipment and/or materials, even though no project has materialized where these items will be used. This can result in our having to incur material equipment and/or material costs, with no deployment plan at delivery. Financing risk has also increased as a result of the deterioration of the

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global economy and the crisis in the financial markets, and as a result, we may forgo certain development opportunities. We believe that capitalized costs for projects under development are recoverable; however, there can be no assurance that any individual project will be completed and reach commercial operation. If these development efforts are not successful, we may abandon a project under development and write off the costs incurred in connection with such project. At the time of abandonment, we would expense all capitalized development costs incurred in connection therewith and could incur additional losses associated with any related contingent liabilities.

The Company has 670 MW under construction at its Maritza project in Bulgaria. Certain delays have occurred in the project. However, at this time, we believe that Maritza will still be completed by the second half of 2010. In the event of further delays of the project, completion of the project and commencement of commercial operations could be delayed beyond this timeframe. In June 2009, the Supreme Court of Chile affirmed a January 2009 decision of the Valparaiso Court of Appeals that the environmental permit for EEC s thermal power plant (Plant) was not properly granted and illegal. Construction of the Plant has stopped as a consequence of the Supreme Court s decision. In September 2009, the Municipality of Puchuncaví issued an order to demolish the Plant on the basis of other permitting issues. In October 2009, Empresa Electrica Campiche (EEC) and AES Gener filed a judicial claim against the Municipality of Puchuncaví before the Civil Judge of the City of Quintero, seeking to revoke the demolition order and asking for an immediate stay of said order. At the request of EEC and Gener, the Civil Judge of Quintero agreed to suspend the order until a final decision on the order is issued. In December 2009, Chilean authorities approved new land use regulations that entitle EEC to reapply for a new environmental permit. Such permit request was requested on January 14, 2010. The new land use regulations were challenged by local groups and this challenge was rejected by the Court of Appeals of Santiago. The local groups have filed a motion to reconsider in the same court. On February 22, 2010, Chilean environmental authorities approved a new environmental permit for EEC. EEC may now request the construction permits so that the Plant s construction can resume. However, while we believe that any challenges to a new permit would be without merit, it is possible that third parties may attempt to challenge any new permit issued by the corresponding authorities. EEC and the construction contractor have agreed on a path forward while construction work stoppage is ongoing. However, if EEC is unable to complete the project, AES may be required to record an impairment of the Campiche project proportional to its indirect ownership, which could have a material impact on earnings in the period in which it is recorded. Based on cash investments through December 31, 2009 and potential termination costs, AES could incur an impairment of approximately $189 million. In the event an impairment charge is recognized with regard to the project, the amount of such impairment will depend on a number of factors, including EEC s ability to recover project costs.

Our acquisitions may not perform as expected.

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

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

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

We have invested in some joint ventures where we own less than a majority of the voting equity in the venture. Very often, we seek to exert a degree of influence with respect to the management and operation of projects in which we have less than a majority of the ownership interests by operating the project pursuant to a management contract, negotiating to obtain positions on management committees or to receive certain limited governance rights, such as rights to veto significant actions. However, we do not always have this type of control over the project in every instance; and we may be dependent on our co-venturers to operate such projects. Our co-venturers may not have the level of experience, technical expertise, human resources, management and other attributes necessary to operate these projects optimally. The approval of co-venturers also may be required for us to receive distributions of funds from projects or to transfer our interest in projects.

In some joint venture agreements where we do have majority control of the voting securities, we have entered into shareholder agreements granting protective minority rights to the other shareholders. For example, Brasiliana Energia (Brasiliana) is a holding company in which we have a controlling equity interest and through which we own three of our four Brazilian businesses: Eletropaulo, Tietê and Uruguaiana. We entered into a shareholders agreement with an affiliate of the Brazilian National Development Bank (BNDES) which owns more than 49 percent of the voting equity of Brasiliana. Among other things, the shareholders agreement requires the consent of both parties before taking certain corporate actions, grants both parties rights of first refusal in connection with the sale of interests in Brasiliana and grants drag-along rights to BNDES. In May, 2007, BNDES notified us that it intends to sell all of its interest in Brasiliana pursuant to public auction (the Brasiliana Sale). BNDES also informed us that if we fail to exercise our right of first refusal to purchase all of its interest in Brasiliana, then BNDES intends to exercise its drag-along rights under the shareholders agreement and cause us to sell all of our interests in Brasiliana in the Brasiliana Sale as well. BNDES has since suspended the auction, however, BNDES may determine to recommence a sale process in the future. In that event, after the auction, if a third party offer has been received in the Brasiliana Sale, we will have 30 days to exercise our right of first refusal to purchase all of BNDES s interest in Brasiliana on the same terms as the third-party offer. If we do not exercise this right and BNDES proceeds to exercise its drag-along rights, then we may be forced to sell all of our interest in Brasiliana. Due to the uncertainty in the sale price at this point in time, we are uncertain whether we will exercise our right of first refusal should BNDES receive a valid third-party offer in the Brasiliana Sale and, if we do, whether we would do it alone or with joint venture partners. Even if we desire to exercise our right of first refusal, we cannot assure that we will have the cash on hand or that debt or equity financing will be available at acceptable terms in order to purchase BNDES s interest in Brasiliana. If we do not exercise our right of first refusal, we cannot be assured that we will not have to record a loss if the sale price is below the book value of our investment in Brasiliana.

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

AES Wind Generation, AES Solar, our GHG Emissions Reduction Projects, and our investments in projects such as energy storage are subject to substantial risks. Projects of this nature are relatively new and have been developed through advancement in technologies which may not be proven or whose commercial application is limited, and which are unrelated to our core business. Some of these projects are dependent upon favorable regulatory incentives, and there is significant uncertainty about the extent to which such favorable regulatory incentives will be available in the future. Furthermore, production levels for our wind, solar, and GHG Emissions Reduction Projects may be dependent upon adequate wind, sunlight, or biogas production which can vary from period to period, resulting in volatility in production levels and profitability. For example, for our wind projects, wind resource estimates are based on probabilities over a ten year period, and are not expected to reflect actual wind energy production in any given year. With regard to GHG Emissions Reduction Projects, there is particular uncertainty about whether agreements providing incentives for reductions in greenhouse gas emissions, such as the Kyoto Protocol, will continue and whether countries around the world will enact or maintain legislation that provides incentives for reductions in greenhouse gas emissions, without which such projects may not be economical or financing for such projects may become unavailable.

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As a result, these projects face considerable risk, including the risk that favorable regulatory regimes expire or are adversely modified. In addition, because these projects depend on technology outside of our expertise in Generation and Utilities, there are risks associated with our ability to develop and manage such projects profitably. Furthermore, at the development or acquisition stage, because of the nascent nature of these industries or the limited experience with the relevant technologies, our ability to predict actual performance results may be hindered and the projects may not perform as predicted. There are also risks associated with the fact that many of these projects exist in new or emerging markets, where long-term fixed price contracts for the major cost and revenue components may be unavailable, which in turn may result in these projects having relatively high levels of volatility.

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

An impairment in the carrying value of goodwill would negatively impact our consolidated results of operations and net worth.

Goodwill is initially recorded at fair value and is not amortized, but is evaluated for impairment at least annually, or more frequently if impairment indicators are present. In assessing the recoverability of goodwill, we make estimates and assumptions about sales, operating margin growth rates and discount rates based on our budgets, business plans, economic projections, anticipated future cash flows and marketplace data. There are inherent uncertainties related to these factors and management s judgment in applying these factors. The fair value of a reporting unit has been determined using an income approach based on the present value of future cash flows of each reporting unit. We could be required to evaluate the recoverability of goodwill outside of the required annual assessment process if we experience situations, including but not limited to, disruptions to the business, unexpected significant declines in operating results, divestiture of a significant component of our business or adverse action or assessment by a regulator. There could also be impairments if our acquisitions do not perform as expected. See further discussion in Risk Factor, *Our Acquisitions May Not Perform as Expected.* These types of events and the resulting analyses could result in goodwill impairment charges in the future. Impairment charges could substantially affect our financial results in the periods of such charges. As of December 31, 2009, we had $1.3 billion of goodwill, which represented approximately 3% of total assets. If current conditions in the global economy continue or worsen, this could increase the risk that we will have to impair goodwill, as further described in Item 7. Management s Discussion & Analysis Global Recession.

Certain of our businesses are sensitive to variations in weather.

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

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In addition, we are dependent upon hydrological conditions prevailing from time to time in the broad geographic regions in which our hydroelectric generation facilities are located. If hydrological conditions result in droughts or other conditions that negatively affect our hydroelectric generation business, our results of operations could be materially adversely affected. In the past, our businesses in Latin America have been negatively impacted by lower than normal rainfall. Similarly, our wind businesses are dependent on adequate wind conditions while the solar projects at AES Solar are dependent on sufficient sunlight. In each case, inadequate wind or sunlight could have material adverse impact on these businesses.

Risks associated with Governmental Regulation and Laws

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

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

- changes in the determination, definition or classification of costs to be included as reimbursable or pass-through costs to be included in the rates we charge our customers, including but not limited to costs incurred to upgrade our power plants to comply with more stringent environmental regulations;
- changes in the determination of what is an appropriate rate of return on invested capital or a determination that a utility s operating income or the rates it charges customers is too high, resulting in a reduction of rates or consumer rebates;
- changes in the definition or determination of controllable or non-controllable costs;
- adverse changes in tax law;
- changes in the definition of events which may or may not qualify as changes in economic equilibrium;
- changes in the timing of tariff increases; or
- other changes in the regulatory determinations under the relevant concessions.

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

In many countries where we conduct business, the regulatory environment is constantly changing or the regulations can be difficult to interpret. As a result, there is risk that we may not properly interpret certain regulations and may not understand the impact of certain regulations on our business. For example, in October 2006, ANEEL, which regulates our utility operations at Sul and Eletropaulo in Brazil, issued Normative Resolution 234 requiring that utilities begin amortizing a liability called Special Obligations beginning with their second tariff reset cycle in 2007 or a later year as an offset to depreciation expense. As of May 23, 2007, the date of the filing of our 2006 Form 10-K, no industry positions or any other consensus had been reached regarding how ANEEL guidance should be applied at that date and accordingly, no adjustments to the financial statements were made relating to Special Obligations in Brazil. Subsequent to May 23, 2007, industry discussions occurred and other Brazilian companies filed Forms 20-F with the SEC reflecting the impact of Resolution 234 in their December 31, 2006 financial statements differently from how the Company accounted for Resolution 234. In the absence of any significant regulatory developments between May 23, 2007 and the date of these other filings, the Company determined that Resolution 234 required us to record an adjustment to our

Special Obligations liability as of December 31, 2006. In part, the decision to record the adjustment led to the restatement of our financial statements in the third quarter of 2007. If we face additional challenges interpreting regulations or changes in regulations, it could have a material adverse impact on our business.

Our Generation business in the United States is subject to the provisions of various laws and regulations administered in whole or in part by the FERC, including the Public Utility Regulatory Policies Act of 1978 (PURPA), the Federal Power Act, and the EPAct 2005. Actions by the FERC and by state utility commissions can have a material effect on our operations.

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

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

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

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

Our businesses are subject to stringent environmental laws and regulations.

Our activities are subject to stringent environmental laws and regulations by many federal, state and local authorities, international treaties and foreign governmental authorities. These laws and regulations generally concern emissions into the air, effluents into the water, use of water, wetlands preservation, remediation of contamination, waste disposal, endangered species and noise regulation, among others. Failure to comply with such laws and regulations or to obtain any necessary environmental permits pursuant to such laws and regulations could result in fines or other sanctions. Environmental laws and regulations affecting power generation and distribution are complex and have tended to become more stringent over time. Congress and other

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domestic and foreign governmental authorities have either considered or implemented various laws and regulations to restrict or tax certain emissions, particularly those involving air and water emissions. See the various descriptions of these laws and regulations contained in Item 1. Business Regulatory Matters Environmental and Land Use Regulations of this Form 10-K. These laws and regulations have imposed, and proposed laws and regulations could impose in the future, additional costs on the operation of our power plants. We have incurred and will continue to incur significant capital and other expenditures to comply with these and other environmental laws and regulations. Changes in, or new, environmental restrictions may force us to incur significant expenses or expenses that may exceed our estimates. There can be no assurance that we would be able to recover all or any increased environmental costs from our customers or that our business, financial condition, including recorded asset values or results of operations would not be materially and adversely affected by such expenditures or any changes in domestic or foreign environmental laws and regulations.

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

The EPA has pursued an enforcement initiative against coal-fired generating plants alleging wide-spread violations of the new source review and prevention of significant deterioration provisions of the CAA. The EPA has brought suit against a number of companies and has obtained settlements with approximately 13 companies over such allegations. The allegations typically involve claims that a company made major modifications to a coal-fired generating unit without proper permit approval and without installing best available control technology. The principal focus of this EPA enforcement initiative is emissions of SO_2 and NO_x. In connection with this enforcement initiative, the EPA has imposed fines and required companies to install improved pollution control technologies to reduce emissions of SO_2 and NO_x. One of our businesses, IPL, is currently the subject of such an EPA enforcement action, and another business, Eastern Energy, has received an information request from the EPA in connection with a possible enforcement action. See Item 3. Legal Proceedings of this Form 10-K for more detail with respect to these EPA enforcement actions and information requests. There can be no assurance that foreign environmental regulatory agencies in countries in which our subsidiaries operate will not pursue similar enforcement initiatives under relevant laws and regulations.

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

As discussed in Item 1. Business Regulatory Matters Environmental and Land Use Regulations, at the international, federal and various regional and state levels, policies are under development to regulate GHG emissions, thereby effectively putting a cost on such emissions in order to create financial incentives to reduce them. In 2009, the Company s subsidiaries operated businesses which had total approximate CO_2 emissions of 74.2 million metric tonnes approximately 39.7 million of which were emitted by businesses located in the United States (both figures ownership adjusted). The Company uses CO_2 emission estimation methodologies supported by The Greenhouse Gas Protocol reporting standard on GHG emissions. For existing power generation plants, CO_2 emissions are either obtained directly from plant continuous emission monitoring systems or calculated from actual fuel heat inputs and fuel type CO_2 emission factors. The estimated annual CO_2 emissions from fossil fuel electric power generation facilities of the Company s subsidiaries that are in construction or development and have received the necessary air permits for commercial operations are approximately 20.6 million metric tonnes (ownership adjusted). This overall estimate is based upon a number of projections and assumptions which may prove to be incorrect such as the forecast dispatch, anticipated plant efficiency, fuel type, CO_2 emissions and our subsidiaries achieving completion of such construction and development projects. However, it is certain that the projects under construction or development when completed will increase emissions of our portfolio and therefore could increase the risks associated with emissions described below. Because there is significant uncertainty regarding these estimates, actual emissions from these projects under construction or development may vary substantially from these estimates.

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

Foreign, federal, state or regional regulation of GHG emissions could have a material adverse impact on the Company s financial performance. The actual impact on the Company s financial performance and the financial performance of the Company s subsidiaries will depend on a number of factors, including among others, the degree and timing of GHG emissions reductions required under any such legislation or regulations, the price and availability of offsets, the extent to which market based compliance options are available, the extent to which our subsidiaries would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market and the impact of such legislation or regulation on the ability of our subsidiaries to recover costs incurred through rate increases or otherwise. As a result of these factors, our cost of compliance could be substantial and could have a material impact on our results of operations. Another factor is the success of our GHG Emissions Reduction Projects, which may generate credits that will help offset our GHG emissions. However, as set forth in the Risk Factor titled Our renewable energy projects and other initiatives face considerable uncertainties including development, operational and regulatory challenges, there is no guarantee that the GHG Emissions Reduction Projects will be successful.

In January 2005, based on European Community Directive 2003/87/EC on Greenhouse Gas Emission Allowance Trading, the European Union Greenhouse Gas Emission Trading Scheme (EU ETS) commenced operation as the largest multi-country GHG emission trading scheme in the world. On February 16, 2005, the Kyoto Protocol became effective. The Kyoto Protocol requires the 40 developed countries that have ratified it to substantially reduce their GHG emissions, including CO_2. To date, compliance with the Kyoto Protocol and the EU ETS has not had a material adverse effect on the Company s consolidated results of operations, financial condition and cash flows.

The United States has not ratified the Kyoto Protocol. In the United States, there currently are no federal mandatory GHG emission reduction programs (including CO_2) affecting the electric power generation facilities of the Company s subsidiaries. However, there is federal GHG legislation pending before the U.S. Congress that would, if enacted, constrain GHG emissions, including CO_2, and/or impose costs on us that could be material to our business or results of operations. There is also a proposed EPA regulation that could result in a requirement for all new sources of GHG emissions of over 250 tons per year, and existing sources planning physical changes that would increase their GHG emissions, to obtain new source review permits from the EPA prior to construction.

Any such regulations could increase our costs directly and indirectly and have a material adverse effect on our business and/or results of operations. See Item 1. Business Regulatory Matters Environmental and Land Use Regulations of this Form 10-K for further discussion about these environmental agreements, laws and regulations.

At the state level, RGGI, a cap-and-trade program covering CO_2 emissions from electric power generation facilities in the Northeast, became effective in January 2009, and the WCI, is also developing market-based programs to address GHG emissions in seven western states. In addition, several states, including California, have adopted comprehensive legislation that, when implemented, will require mandatory GHG reductions from several industrial sectors, including the electric power generation industry. See Item 1. Business Regulatory Matters Environmental and Land Use Regulations of this Form 10-K for further discussion about the U.S. state environmental regulations we face. At this time, other than with regard to RGGI (further described below), the Company cannot estimate the costs of compliance with U.S. federal, regional or state CO_2 emissions reductions legislation or initiatives, due to the fact that these proposals are in earlier stages of development and any final regulations or legislation, if adopted, could vary drastically from current proposals.

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The RGGI program became effective in January 2009. The first regional auction of RGGI allowances needed to be acquired by power generators to comply with state programs implementing RGGI was held in September 2008, with subsequent auctions occurring approximately every quarter. Our subsidiaries in New York, New Jersey, Connecticut and Maryland are subject to RGGI. Of the approximately 39.7 million metric tonnes of CO_2 emitted in the United States by our subsidiaries in 2009 (ownership adjusted), approximately 9.7 million metric tonnes were emitted in U.S. states participating in RGGI. Over the past three years, such emissions averaged 11.1 million metric tonnes. We believe that due to the absence of allowance allocations, RGGI could have a material adverse impact on the Company s consolidated results of operations, financial condition and cash flows. While CO_2 emissions from businesses operated by subsidiaries of the Company are calculated globally in metric tonnes, RGGI allowances are denominated in short tons. (1 metric tonne equals 2,200 pounds and 1 short ton equals 2,000 pounds.) For forecasting purposes, the Company has modeled the impact of CO_2 compliance based on a 3-year average of CO_2 emissions for its businesses that are subject to RGGI and that may not be able to pass through compliance costs. The model includes a conversion from metric tonnes to short tons as well as the impact of some market recovery by merchant plants and contractual and regulatory provisions. The model also utilizes a price of $2.05 per allowance under RGGI. The source of this allowance price estimate was the clearing price in the sixth and most recent RGGI allowance auction held in December 2009. Based on these assumptions, the Company estimates that the RGGI compliance costs could be approximately $17.5 million per year from 2010 through 2011, which is the last year of the first RGGI compliance period. Given the fact that the assumptions utilized in the model may prove to be incorrect, there is a significant risk that our actual compliance costs under RGGI will differ from our estimates by a material amount and that our model could underestimate our costs of compliance.

In addition to government regulators, other groups such as politicians, environmentalists and other private parties have expressed increasing concern about GHG emissions. For example, certain financial institutions have expressed concern about providing financing for facilities which would emit GHGs, which can affect our ability to obtain capital, or if we can obtain capital, to receive it on commercially viable terms. In addition, rating agencies may decide to downgrade our credit ratings based on the emissions of the businesses operated by our subsidiaries or increased compliance costs which could make financing unattractive. In addition, environmental groups and other private plaintiffs have brought and may decide to bring additional private lawsuits against the Company because of its subsidiaries GHG emissions. The Company is facing and may face in the future private lawsuits relating to GHG emissions that may have a material impact on the Company s results of operations. In two recent cases in the U.S., one which involves the Company, federal appellate courts have reversed the dismissal of nuisance and other claims against emitters of GHG. The plaintiffs in one of the cases seek damages for injuries allegedly caused by GHG emissions while the plaintiffs in the other case seek injunctive relief to prevent further GHG emissions. Unless the U.S. Congress acts to preempt such suits as part of comprehensive federal legislation, additional lawsuits may be brought against the Company or its subsidiaries. At this stage of the litigation, it is impossible to predict whether such lawsuits are likely to prevail or result in a damages award. Consequently, it is impossible to determine whether such lawsuits are likely to have a material adverse effect on the Company s consolidated results of operations and financial condition.

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

Company s subsidiaries. Changes in temperature, precipitation and snow pack conditions also could affect the amount and timing of hydroelectric generation.

The level of GHG emissions made by subsidiaries of the Company is not a factor in the compensation of executives of the Company.

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

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

Our subsidiaries have operations in the United States and various non-U.S. jurisdictions. As such, we are subject to the tax laws and regulations of the U.S. federal, state and local governments and of many non-U.S. jurisdictions. From time to time, legislative measures, such as the interest deferral provision recently announced in the President s Fiscal 2011 budget impacting U.S. based multinationals, may be enacted that could adversely affect overall tax positions. There can be no assurance that our effective tax rate or tax payments will not be adversely affected by these initiatives. In addition, U.S. federal, state and local, as well as non-U.S., tax laws and regulations are extremely complex and subject to varying interpretations. There can be no assurance that our tax positions will be sustained if challenged by relevant tax authorities.

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

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

The SEC is conducting an informal inquiry relating to our restatements.

We have been cooperating with an informal inquiry by the SEC Staff concerning our past restatements and related matters, and have been providing information and documents to the SEC Staff on a voluntary basis. Although we have not received correspondence regarding this inquiry for some time, we have not been advised that the matter is closed. Because we are unable to predict the outcome of this inquiry, the SEC Staff may disagree with the manner in which we have accounted for and reported the financial impact of the adjustments to previously filed financial statements and there may be a risk that the inquiry by the SEC could lead to circumstances in which we may have to further restate previously filed financial statements, amend prior filings or take other actions not currently contemplated.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

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

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ITEM 3. LEGAL PROCEEDINGS

The Company is involved in certain claims, suits and legal proceedings in the normal course of business, some of which are described below. The Company has accrued for litigation and claims where it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. The Company believes, based upon information it currently possesses and taking into account established reserves for estimated liabilities and its insurance coverage, that the ultimate outcome of these proceedings and actions is unlikely to have a material adverse effect on the Company s financial statements. However, it is reasonably possible that some matters could be decided unfavorably to the Company, and could require the Company to pay damages or make expenditures in amounts that could be material but cannot be estimated as of December 31, 2009. The Company has evaluated claims, in accordance with the accounting guidance for contingencies, that it deems both probable and reasonably estimable and accordingly, has recorded aggregate reserves for all claims for approximately $482 million and $389 million as of December 31, 2009 and 2008, respectively.

In 1989, Centrais Elétricas Brasileiras S.A. (Eletrobrás) filed suit in the Fifth District Court in the State of Rio de Janeiro against Eletropaulo Eletricidade de São Paulo S.A. (EEDSP) relating to the methodology for calculating monetary adjustments under the parties financing agreement. In April 1999, the Fifth District Court found for Eletrobrás and in September 2001, Eletrobrás initiated an execution suit in the Fifth District Court to collect approximately R$1.0 billion ($577 million) from Eletropaulo (as estimated by Eletropaulo) and a lesser amount from an unrelated company, Companhia de Transmissão de Energia Elétrica Paulista (CTEEP) (Eletropaulo and CTEEP were spun off from EEDSP pursuant to its privatization in 1998). In November 2002, the Fifth District Court rejected Eletropaulo s defenses in the execution suit. Eletropaulo appealed and in September 2003, the Appellate Court of the State of Rio de Janeiro ruled that Eletropaulo was not a proper party to the litigation because any alleged liability was transferred to CTEEP pursuant to the privatization. In June 2006, the Superior Court of Justice (SCJ) reversed the Appellate Court s decision and remanded the case to the Fifth District Court for further proceedings, holding that Eletropaulo s liability, if any, should be determined by the Fifth District Court. Eletropaulo s subsequent appeals to the Special Court (the highest court within the SCJ) and the Supreme Court of Brazil have been dismissed. Eletrobrás has requested that the amount of Eletropaulo s alleged debt be determined by an accounting expert appointed by the Fifth District Court. Eletropaulo has consented to the appointment of such an expert, subject to a reservation of rights. After the amount of the alleged debt is determined, Eletrobrás may resume the execution suit in the Fifth District Court at any time. If Eletrobrás does so, Eletropaulo will be required to provide security in the amount of its alleged liability. In that case, if Eletrobrás requests the seizure of such security and the Fifth District Court grants such request, Eletropaulo s results of operations may be materially adversely affected. In addition, in February 2008, CTEEP filed a lawsuit in the Fifth District Court against Eletrobrás and Eletropaulo seeking a declaration that CTEEP is not liable for any debt under the financing agreement. Eletropaulo believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In September 1999, a state appellate court in Minas Gerais, Brazil, granted a temporary injunction suspending the effectiveness of a shareholders agreement between Southern Electric Brasil Participacoes, Ltda. (SEB) and the state of Minas Gerais concerning CEMIG, an integrated utility in Minas Gerais. The Company s investment in CEMIG is through SEB. This shareholders agreement granted SEB certain rights and powers with respect to the management of CEMIG (Special Rights). In March 2000, a lower state court in Minas Gerais held the shareholders agreement invalid where it purported to grant SEB the Special Rights and enjoined the exercise of the Special Rights. In August 2001, the state appellate court denied an appeal of the decision and extended the injunction. In October 2001, SEB filed appeals against the state appellate court s decision with the SCJ and the Supreme Court. The state appellate court denied access of these appeals to the higher courts, and in August 2002 SEB filed interlocutory appeals against such denial with the SCJ and the Supreme Court. In December 2004, the SCJ declined to hear SEB s appeal. In December 2009, the Supreme Court also declined to hear SEB s appeal. In February 2010, SEB filed an appeal with the Supreme Court Collegiate. There can be no assurances that SEB will be successful in any such appeal. Failure to prevail in this matter will preclude SEB from obtaining management control of CEMIG under the Special Rights.

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In August 2000, the FERC announced an investigation into the organized California wholesale power markets in order to determine whether rates were just and reasonable. Further investigations involved alleged market manipulation. FERC requested documents from each of the AES Southland, LLC plants and AES Placerita, Inc. AES Southland and AES Placerita have cooperated fully with the FERC investigations. AES Southland was not subject to refund liability because it did not sell into the organized spot markets due to the nature of its tolling agreement. After hearings at FERC, AES Placerita was found subject to refund liability of $588,000 plus interest for spot sales to the California Power Exchange from October 2, 2000 to June 20, 2001. As FERC investigations and hearings progressed, numerous appeals on related issues were filed with the U.S. Court of Appeals for the Ninth Circuit. Over the past five years, the Ninth Circuit issued several opinions that had the potential to expand the scope of the FERC proceedings and increase refund exposure for AES Placerita and other sellers of electricity. Following remand of one of the Ninth Circuit appeals in March 2009, FERC started a new hearing process involving AES Placerita and other sellers. In May 2009, AES Placerita entered into a settlement, subject to FERC approval, concerning the claims before FERC against AES Placerita relating to the California energy crisis of 2000-2001, including the California refund proceeding. Pursuant to the settlement, AES Placerita paid $6 million and assigned a receivable of $168,119 due to it from the California Power Exchange in return for a release of all claims against it at FERC by the settling parties and other consideration. In July 2009, FERC approved the settlement as submitted. In excess of 97% of the buyers in the market elected to join the settlement. A small amount of AES Placerita s settlement payment was placed in escrow for buyers that did not join the settlement (non-settling parties). It is unclear whether the escrowed funds will be enough to satisfy any additional sums that might be determined to be owed to non-settling parties at the conclusion of the FERC proceedings concerning the California energy crisis. However, any such additional sums are expected to be immaterial to the Company s consolidated financial statements. In July 2009, one non-settling party, the Sacramento Municipal Utility District (SMUD), requested that the FERC rehear its order approving the settlement. The FERC denied SMUD s request in September 2009. In November 2009, SMUD filed an appeal of the FERC s approval of the settlement with the U.S. Court of Appeals for the District of Columbia Circuit, which was later transferred to the Ninth Circuit. The settlement agreement is still effective and will continue to remain effective unless it is vacated by the Ninth Circuit.

In August 2001, the Grid Corporation of Orissa, India, now Gridco Ltd (Gridco), filed a petition against the Central Electricity Supply Company of Orissa Ltd. (CESCO), an affiliate of the Company, with the Orissa Electricity Regulatory Commission (OERC), alleging that CESCO had defaulted on its obligations as an OERC-licensed distribution company, that CESCO management abandoned the management of CESCO, and asking for interim measures of protection, including the appointment of an administrator to manage CESCO. Gridco, a state-owned entity, is the sole wholesale energy provider to CESCO. Pursuant to the OERC s August 2001 order, the management of CESCO was replaced with a government administrator who was appointed by the OERC. The OERC later held that the Company and other CESCO shareholders were not necessary or proper parties to the OERC proceeding. In August 2004, the OERC issued a notice to CESCO, the Company and others giving the recipients of the notice until November 2004 to show cause why CESCO s distribution license should not be revoked. In response, CESCO submitted a business plan to the OERC. In February 2005, the OERC issued an order rejecting the proposed business plan. The order also stated that the CESCO distribution license would be revoked if an acceptable business plan for CESCO was not submitted to and approved by the OERC prior to March 31, 2005. In its April 2, 2005 order, the OERC revoked the CESCO distribution license. CESCO has filed an appeal against the April 2, 2005 OERC order and that appeal remains pending in the Indian courts. In addition, Gridco asserted that a comfort letter issued by the Company in connection with the Company s indirect investment in CESCO obligates the Company to provide additional financial support to cover all of CESCO s financial obligations to Gridco. In December 2001, Gridco served a notice to arbitrate pursuant to the Indian Arbitration and Conciliation Act of 1996 on the Company, AES Orissa Distribution Private Limited (AES ODPL), and Jyoti Structures (Jyoti) pursuant to the terms of the CESCO Shareholders Agreement between Gridco, the Company, AES ODPL, Jyoti and CESCO (the CESCO arbitration). In the arbitration, Gridco appeared to be seeking approximately $189 million in damages, plus undisclosed penalties and interest, but a detailed alleged damage analysis was not filed by Gridco. The Company counterclaimed against Gridco for damages. In June 2007, a 2-to-1 majority of the arbitral tribunal rendered its award rejecting Gridco s claims and holding that none of the respondents, the Company, AES ODPL, or Jyoti, had any liability to Gridco. The respondents counterclaims were also rejected. The Company subsequently filed an application to recover its costs of the arbitration, which is under consideration by the tribunal. In addition, in September 2007, Gridco filed a challenge of the arbitration award with the local Indian court. In June 2008, Gridco filed a separate application with the local Indian court for an order enjoining the Company from selling or otherwise transferring its shares in Orissa Power Generation Corporation Ltd s (OPGC), and requiring the Company to provide security in the amount of the contested damages in the CESCO arbitration until Gridco s challenge to the arbitration award is resolved. The Company believes that it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In early 2002, Gridco made an application to the OERC requesting that the OERC initiate proceedings regarding the terms of OPGC s existing PPA with Gridco. In response, OPGC filed a petition in the Indian courts to block any such OERC proceedings. In early 2005, the Orissa High Court upheld the OERC s jurisdiction to initiate such proceedings as requested by Gridco. OPGC appealed that High Court s decision to the Supreme Court and sought stays of both the High Court s decision and the underlying OERC proceedings regarding the PPAs terms. In April 2005, the Supreme Court granted OPGC s requests and ordered stays of the High Court s decision and the OERC proceedings with respect to the PPA s terms. The matter is awaiting further hearing. Unless the Supreme Court finds in favor of OPGC s appeal or otherwise prevents the OERC s proceedings regarding the PPA s terms, the OERC will likely lower the tariff payable to OPGC under the PPA, which would have an adverse impact on OPGC s financials. OPGC believes that it has meritorious claims and defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In March 2003, the office of the Federal Public Prosecutor for the State of São Paulo, Brazil (MPF) notified AES Eletropaulo that it had commenced an inquiry related to the BNDES financings provided to AES Elpa and AES Transgás and the rationing loan provided to Eletropaulo, changes in the control of Eletropaulo, sales of assets by Eletropaulo and the quality of service provided by Eletropaulo to its customers, and requested various documents from Eletropaulo relating to these matters. In July 2004, the MPF filed a public civil lawsuit in the Federal Court of Sao Paulo (FSCP) alleging that BNDES violated Law 8429/92 (the Administrative Misconduct Act) and BNDES s internal rules by: (1) approving the AES Elpa and AES Transgás loans; (2) extending the payment terms on the AES Elpa and AES Transgás loans; (3) authorizing the sale of Eletropaulo s preferred shares at a stock-market auction; (4) accepting Eletropaulo s preferred shares to secure the loan provided to Eletropaulo; and (5) allowing the restructurings of Light Serviços de Eletricidade S.A. (Light) and Eletropaulo. The MPF also named AES Elpa and AES Transgás as defendants in the lawsuit because they allegedly benefited from BNDES s alleged violations. In May 2006, the FCSP ruled that the MPF could pursue its claims based on the first, second, and fourth alleged violations noted above. The MPF subsequently filed an interlocutory appeal with the Federal Court of Appeals (FCA) seeking to require the FCSP to consider all five alleged violations. Also, in July 2006, AES Elpa and AES Transgás filed an interlocutory appeal with the FCA, which was subsequently consolidated with the MPF s interlocutory appeal, seeking a transfer of venue and to enjoin the FCSP from considering any of the alleged violations. In June 2009, the FCA granted the injunction sought by AES Elpa and AES Transgás and transferred the case to the Federal Court of Rio de Janeiro. MPF likely will appeal. The MPF s lawsuit before the FCSP has been stayed pending a final decision on the interlocutory appeals. AES Elpa and AES Transgás believe they have meritorious defenses to the allegations asserted against them and will defend themselves vigorously in these proceedings; however, there can be no assurances that they will be successful in their efforts.

AES Florestal, Ltd. (Florestal), had been operating a pole factory and had other assets, including a wooded area known as Horto Renner, in the State of Rio Grande do Sul, Brazil (collectively, Property). Florestal had been under the control of AES Sul (Sul) since October 1997, when Sul was created pursuant to a privatization by the Government of the State of Rio Grande do Sul. After it came under the control of Sul, Florestal performed an environmental audit of the entire operational cycle at the pole factory. The audit discovered 200 barrels of solid creosote waste and other contaminants at the pole factory. The audit concluded

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that the prior operator of the pole factory, Companhia Estadual de Energia Elétrica (CEEE), had been using those contaminants to treat the poles that were manufactured at the factory. Sul and Florestal subsequently took the initiative of communicating with Brazilian authorities, as well as CEEE, about the adoption of containment and remediation measures. The Public Attorney s Office has initiated a civil inquiry (Civil Inquiry n. 24/05) to investigate potential civil liability and has requested that the police station of Triunfo institute a police investigation (IP number 1041/05) to investigate potential criminal liability regarding the contamination at the pole factory. The parties filed defenses in response to the civil inquiry. The Public Attorney s Office then requested an injunction which the judge rejected on September 26, 2008. The Public Attorney s office has a right to appeal the decision. The environmental agency (FEPAM) has also started a procedure (Procedure n. 088200567/059) to analyze the measures that shall be taken to contain and remediate the contamination. Also, in March 2000, Sul filed suit against CEEE in the 2nd Court of Public Treasure of Porto Alegre seeking to register in Sul s name the Property that it acquired through the privatization but that remained registered in CEEE s name. During those proceedings, AES subsequently waived its claim to re-register the Property and asserted a claim to recover the amounts paid for the Property. That claim is pending. In November 2005, the 7th Court of Public Treasure of Porto Alegre ruled that the Property must be returned to CEEE. CEEE has had sole possession of Horto Renner since September 2006 and of the rest of the Property since April 2006. In February 2008, Sul and CEEE signed a Technical Cooperation Protocol pursuant to which they requested a new deadline from FEPAM in order to present a proposal. In March 2008, the State Prosecution office filed a Public Class Action against AES Florestal, AES Sul and CEEE, requiring an injunction for the removal of the alleged sources of contamination and the payment of an indemnity in the amount of R$6 million ($3 million). The injunction was rejected and the case is in the evidentiary stage awaiting the judge s determination concerning the production of expert evidence. The above referenced proposal was delivered on April 8, 2008. FEPAM responded by indicating that the parties should undertake the first step of the proposal which would be to retain a contractor. In its response Sul indicated that such step should be undertaken by CEEE as the relevant environmental events resulted from CEEE s operations. It is estimated that remediation could cost approximately R$14.7 million ($8 million). Discussions between Sul and CEEE are ongoing.

In January 2004, the Company received notice of a Formulation of Charges filed against the Company by the Superintendence of Electricity of the Dominican Republic. In the Formulation of Charges, the Superintendence asserts that the existence of three generation companies (Empresa Generadora de Electricidad Itabo, S.A. (Itabo), Dominican Power Partners, and AES Andres BV) and one distribution company (Empresa Distribuidora de Electricidad del Este, S.A. (Este)) in the Dominican Republic, violates certain cross-ownership restrictions contained in the General Electricity Law of the Dominican Republic. In February 2004, the Company filed in the First Instance Court of the National District of the Dominican Republic an action seeking injunctive relief based on several constitutional due process violations contained in the Formulation of Charges (Constitutional Injunction). In February 2004, the Court granted the Constitutional Injunction and ordered the immediate cessation of any effects of the Formulation of Charges, and the enactment by the Superintendence of Electricity of a special procedure to prosecute alleged antitrust complaints under the General Electricity Law. In March 2004, the Superintendence of Electricity appealed the Court s decision. In July 2004, the Company divested any interest in Este. The Superintendence of Electricity s appeal is pending. The Company believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In April 2004, BNDES filed a collection suit against SEB, a subsidiary of the Company, to obtain the payment of R$3.8 billion ($2.2 billion), which includes principal, interest and penalties under the loan agreement between BNDES and SEB, the proceeds of which were used by SEB to acquire shares of CEMIG. In May 2004, the 15th Federal Circuit Court (Circuit Court) ordered the attachment of SEB s CEMIG shares, which were given as collateral for the loan, as well as dividends paid by CEMIG to SEB. At the time of the attachment, the shares were worth approximately R$762 million ($439 million). In December 2006, SEB s defense was ruled groundless by the Circuit Court. The Federal Court of Appeals affirmed that decision in February 2009. SEB intends to file further appeals. BNDES has seized a total of approximately R$760 million ($438 million) in attached dividends to date, with the approval of the Circuit Court, and is seeking to recover additional attached dividends. Also, BNDES has filed a plea to seize the attached CEMIG shares. The Circuit Court will consider BNDES s request to seize the attached CEMIG shares after the net value of the alleged debt is recalculated in light of BNDES s seizure of dividends. SEB believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In July 2004, the Corporación Dominicana de Empresas Eléctricas Estatales (CDEEE) filed lawsuits against Itabo, an affiliate of the Company, in the First and Fifth Chambers of the Civil and Commercial Court of First Instance for the National District. CDEEE alleges in both lawsuits that Itabo spent more than was necessary to rehabilitate two generation units of an Itabo power plant and, in the Fifth Chamber lawsuit, that those funds were paid to affiliates and subsidiaries of AES Gener and Coastal Itabo, Ltd. (Coastal), a former shareholder of Itabo, without the required approval of Itabo s board of administration. In the First Chamber lawsuit, CDEEE seeks an accounting of Itabo s transactions relating to the rehabilitation. In November 2004, the First Chamber dismissed the case for lack of legal basis. On appeal, in October 2005 the Court of Appeals of Santo Domingo ruled in Itabo s favor, reasoning that it lacked jurisdiction over the dispute because the parties contracts mandated arbitration. The Supreme Court of Justice is considering CDEEE s appeal of the Court of Appeals decision. In the Fifth Chamber lawsuit, which also names Itabo s former president as a defendant, CDEEE seeks $15 million in damages and the seizure of Itabo s assets. In October 2005, the Fifth Chamber held that it lacked jurisdiction to adjudicate the dispute given the arbitration provisions in the parties contracts. The First Chamber of the Court of Appeal ratified that decision in September 2006. In a related proceeding, in May 2005, Itabo filed a lawsuit in the U.S. District Court for the Southern District of New York seeking to compel CDEEE to arbitrate its claims. The petition was denied in July 2005. Itabo s appeal of that decision to the U.S. Court of Appeals for the Second Circuit has been stayed since September 2006. Further, in September 2006, in an International Chamber of Commerce arbitration, an arbitral tribunal determined that it lacked jurisdiction to decide arbitration claims concerning these disputes. Itabo believes it has meritorious claims and defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In April 2006, a putative class action complaint was filed in the U.S. District Court for the Southern District of Mississippi (District Court) on behalf of certain individual plaintiffs and all residents and/or property owners in the State of Mississippi who allegedly suffered harm as a result of Hurricane Katrina, and against the Company and numerous unrelated companies, whose alleged greenhouse gas emissions allegedly increased the destructive capacity of Hurricane Katrina. The plaintiffs assert unjust enrichment, civil conspiracy/aiding and abetting, public and private nuisance, trespass, negligence, and fraudulent misrepresentation and concealment claims against the defendants. The plaintiffs seek damages relating to loss of property, loss of business, clean-up costs, personal injuries and death, but do not quantify their alleged damages. In August 2007, the District Court dismissed the case. The plaintiffs subsequently appealed to the U.S. Court of Appeals for the Fifth Circuit, which heard oral arguments in November 2008. In October 2009, the Fifth Circuit affirmed the District Court s dismissal of the plaintiffs unjust enrichment, fraudulent misrepresentation, and civil conspiracy claims. However, the Fifth Circuit reversed the District Court s dismissal of the plaintiffs public and private nuisance, trespass, and negligence claims, and remanded those claims to the District Court for further proceedings. The Company has filed a petition seeking en banc review at the Fifth Circuit. The Company believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In July 2007, the Competition Committee of the Ministry of Industry and Trade of the Republic of Kazakhstan (the Competition Committee) ordered Nurenergoservice, an AES subsidiary, to pay approximately 18 billion KZT ($122 million) for alleged antimonopoly violations in 2005 through the first quarter of 2007. The Competition Committee s order was affirmed by the economic court in April 2008 (April 2008 Decision). The economic court also issued an injunction to secure Nurenergoservice s alleged liability, freezing Nurenergoservice s bank accounts and prohibiting Nurenergoservice from transferring or disposing of its property. Nurenergoservice s subsequent appeals to the court of appeals were rejected. In February 2009, the Antimonopoly Agency (the Competition Committee s successor) seized approximately 783 million KZT ($5 million) from a frozen Nurenergoservice bank account in partial satisfaction of Nurenergoservice s alleged damages liability. However, on appeal to the Kazakhstan Supreme Court, in October 2009, the Supreme Court annulled the decisions of the lower courts because of procedural irregularities and remanded the case to the economic court for reconsideration. On remand, in January 2010, the economic court reaffirmed its April 2008 Decision. Nurenergoservice will appeal. In separate but related proceedings, in August 2007, the Competition Committee ordered Nurenergoservice to pay approximately 1.8 billion KZT ($12 million) in administrative fines for its alleged antimonopoly violations. Nurenergoservice s appeal to the administrative court was rejected in February 2009. Given the adverse court decisions against Nurenergorservice, the Antimonopoly Agency may attempt to seize Nurenergoservice s remaining assets, which are immaterial to the Company s consolidated financial statements. The Compensation Committee s successor, the Antimonopoly Agency, has not indicated whether it intends to assert claims against Nurenergoservice for alleged antimonopoly violations post first quarter 2007. Nurenergoservice believes it has meritorious claims and defenses; however, there can be no assurances that it will prevail in these proceedings.

In December 2008, the Antimonopoly Agency ordered Ust-Kamenogorsk HPP (UK HPP), a hydroelectric plant under AES concession, to pay approximately 1.1 billion KZT ($7 million) for alleged antimonopoly violations in February through November 2007. The economic court of first instance has issued an injunction to secure UK HPP s alleged liability, among other things freezing UK HPP s bank accounts. Also, in March 2009, the economic court affirmed the Antimonopoly Agency s order. UK HPP s subsequent appeal to the court of appeals (first panel) was dismissed in April 2009. In June 2009, UK HPP paid the alleged damages and thus the economic court thereafter canceled the injunction on UK HPP s assets. UK HPP filed an appeal with the Kazakhstan Supreme Court, which was rejected. Furthermore, the Antimonopoly Agency has initiated administrative proceedings against UK HPP for its alleged antimonopoly violations. In May 2009, the administrative court of first instance ordered UK HPP to pay approximately 99 million KZT ($665,000) in administrative fines, which UK HPP did in June 2009.

In April 2009, the Antimonopoly Agency initiated an investigation of the power sales of UK HPP and Shulbinsk HPP, another hydroelectric plant under AES concession (collectively, the Hydros), in January through February 2009. The investigation has been suspended pending the outcome of judicial proceedings concerning the inclusion of the Hydros on the list of dominant suppliers in Eastern Kazakhstan and the legality of the underlying Antimonopoly Agency investigation. If the Hydros fail to prove in those proceedings that they are not dominant suppliers and/or that the Antimonopoly Agency s investigation is groundless, the Antimonopoly Agency s investigation will resume. The Hydros believe they have meritorious defenses and will assert them vigorously in any formal proceeding concerning the investigation; however, there can be no assurances that they will be successful in their efforts.

In April 2009, the Antimonopoly Agency initiated an investigation of Ust-Kamenogorsk TETS LLP s (UKT) power sales in 2008 through February 2009. The Antimonopoly Agency subsequently concluded that UKT abused its market position and charged monopolistically high prices for power and should pay an administrative fine of approximately KZT 136 million ($1 million). The Antimonopoly Agency later sought an order from the administrative court requiring UKT to pay the fine. The administrative court proceedings have been suspended pending the outcome of judicial proceedings concerning UKT s challenge of the underlying Antimonopoly Agency investigation. Those judicial proceedings are ongoing. If UKT fails to prevail in those proceedings, the administrative court likely will proceed to order UKT to pay the administrative fine and disgorge the profits from the sales at issue, estimated by the Antimonopoly Agency to be approximately 514 million KZT ($3 million). UKT believes it has meritorious defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In September 2007, the New York Attorney General issued a subpoena to the Company seeking documents and information concerning the Company s analysis and public disclosure of the potential impacts that GHG legislation and climate change from GHG emissions might have on the Company s operations and results. The Company produced documents and information in response to the subpoena. In November 2009, the parties executed an Assurance of Discontinuance (AOD) ending the New York Attorney General s inquiry and requiring the Company, among other things, to continue disclosing certain greenhouse gas emissions issues in its Forms 10-K for the four years following the AOD s execution.

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In November 2007, the International Brotherhood of Electrical Workers, Local Union No. 1395, and sixteen individual retirees, (the Complainants), filed a complaint at the Indiana Utility Regulatory Commission (IURC) seeking enforcement of their interpretation of the 1995 final order and associated settlement agreement resolving IPL s basic rate case. The Complainants requested that the IURC conduct an investigation of IPL s failure to fund the Voluntary Employee Beneficiary Association Trust (VEBA Trust) at a level of approximately $19 million per year. The VEBA Trust was spun off to an independent trustee in 2001. The complaint sought an IURC order requiring IPL to make contributions to place the VEBA Trust in the financial position in which it allegedly would have been had IPL not ceased making annual contributions to the VEBA Trust after its spin off. The complaint also sought an IURC order requiring IPL to resume making annual contributions to the VEBA Trust. IPL filed a motion to dismiss and both parties sought summary judgment in the IURC proceeding. In May 2009, the IURC issued an order granting summary judgment in favor of IPL and in June 2009, the Complainants filed an appeal of the IURC s May 2009 order with the Indiana Court of Appeals. On January 29, 2010, the appellate court affirmed the IURC s determination. Absent a petition for reconsideration, the Complainants have 30 days to petition for transfer to the Indiana Supreme Court. IPL believes it has meritorious defenses to the Complainants claims and it will continue to assert them vigorously in all proceedings; however, there can be no assurances that it will be successful in its efforts.

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska, filed a complaint in the U.S. District Court for the Northern District of California against the Company and numerous unrelated companies, claiming that the defendants alleged GHG emissions are destroying the plaintiffs alleged land. The plaintiffs assert nuisance and concert of action claims against the Company and the other defendants, and a conspiracy claim against a subset of the other defendants. The plaintiffs seek to recover relocation costs, indicated in the complaint to be from $95 million to $400 million, and other alleged damages from the defendants, which are not quantified. The Company filed a motion to dismiss the case, which the District Court granted in October 2009. The plaintiffs have appealed to the U.S. Court of Appeals for the Ninth Circuit. The Company believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In June 2009, the Supreme Court of Chile affirmed a January 2009 decision of the Valparaiso Court of Appeals that the environmental permit for EEC s thermal power plant (Plant) was not properly granted and illegal. Construction of the Plant has stopped as a consequence of the Supreme Court s decision. In September 2009, the Municipality of Puchuncaví issued an order to demolish the Plant on the basis of other permitting issues. In October 2009, EEC and AES Gener filed a judicial claim against the Municipality of Puchuncaví before the Civil Judge of the City of Quintero, seeking to revoke the demolition order and asking for an immediate stay of said order. At the request of EEC and Gener, the Civil Judge of Quintero agreed to suspend the order until a final decision on the order is issued. In December 2009, Chilean authorities approved new land use regulations that entitle EEC to reapply for a new environmental permit. Such permit request was requested on January 14, 2010. The new land use regulations were challenged by local groups and this challenge was rejected by the Court of Appeals of Santiago. The local groups have filed a motion to reconsider in the same court. Once the new environmental permit is granted by the environmental authorities, EEC will request the construction permits so that the Plant s construction can resume. However, while we believe that any challenges to a new permit would be without merit, it is possible that third parties may attempt to challenge any new permit issued by the corresponding authorities. EEC and the construction contractor have agreed on a path forward while construction work stoppage is ongoing. However, if EEC is unable to complete the project, AES may be required to record an impairment of the Campiche project proportional to its indirect ownership, which could have a material impact on earnings in the period in which it is recorded. Based on cash investments through December 31, 2009 and potential termination costs, AES could incur an impairment of approximately $189 million. In the event an impairment charge is recognized with regard to the project, the amount of such impairment will depend on a number of factors, including EEC s ability to recover project costs.

A public civil action has been asserted against Eletropaulo and Associação Desportiva Cultural Eletropaulo (the Associação) relating to alleged environmental damage caused by construction of the Associação near

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Guarapiranga Reservoir. The initial decision that was upheld by the Appellate Court of the State of Sao Paulo in 2006 found that Eletropaulo should either repair the alleged environmental damage by demolishing certain construction and reforesting the area, pursuant to a project which would cost approximately $628,000, or pay an indemnification amount of approximately $5 million. Eletropaulo has appealed this decision to the Supreme Court and is awaiting a decision.

In 2007, a lower court issued a decision related to a 1993 claim that was filed by the Public Attorney s office against Eletropaulo, the São Paulo State Government, SABESP (a state owned company), CETESB (a state owned company) and DAEE (the municipal Water and Electric Energy Department), alleging that they were liable for pollution of the Billings Reservoir as a result of pumping water from Pinheiros River into Billings Reservoir. The events in question occurred while Eletropaulo was a state owned company. An initial lower court decision in 2007 found the parties liable for the payment of approximately $230 million for remediation. Eletropaulo subsequently appealed the decision to the Appellate Court of the State of Sao Paulo which reversed the lower court decision. The Public Attorney s Office has filed appeals to both Superior Court of Justice (SCJ) and the Supreme Court (SC) and such appeals were answered by Eletropaulo in the fourth quarter of 2009. Eletropaulo believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

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

In November 2007, the U.S. Department of Justice (DOJ) notified AES Thames, LLC (AES Thames) that the EPA had requested that the DOJ file a federal court action against AES Thames for alleged violations of the CAA, the CWA, the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and the Emergency Planning and Community Right-to-Know Act (EPCRA), in particular alleging that AES Thames had violated (i) the terms of its Prevention of Significant Deterioration (PSD) air permits in the calculation of its steam load permit limit; and (ii) the CWA, CERCLA and EPCRA in connection with two spills of chlorinating agents that occurred in 2006. The DOJ subsequently indicated that it would like to settle this matter prior to filing a suit and negotiations are ongoing. During such discussions, the DOJ and EPA have accepted AES Thames method of operation and have asked AES Thames to seek a minor permit modification to clarify the air permit condition in a manner that is consistent with AES Thames historical method of operation. On October 21, 2008, the DOJ proposed a civil penalty of $245,000 for the alleged violations. The Company believes that it has meritorious defenses to the claims asserted against it and if a settlement cannot be achieved, the Company will defend itself vigorously in any lawsuit.

In December 2008, the National Electricity Regulatory Entity of Argentina (ENRE) filed a criminal action in the National Criminal and Correctional Court of Argentina against the board of directors and administrators of EDELAP. ENRE s action concerns certain bank cancellations of EDELAP debt in 2006 and 2007, which were accomplished through transactions between the banks and related AES companies. ENRE claims that EDELAP should have reflected in its accounts the alleged benefits of the transactions that were allegedly obtained by the related companies. EDELAP believes that the allegations lack merit; however, there can be no assurances that its board and administrators will prevail in the action.

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In February 2009, a CAA Section 114 information request from the EPA regarding Cayuga and Somerset was received. The request seeks various operating and testing data and other information regarding certain types of projects at the Cayuga and Somerset facilities, generally for the time period from January 1, 2000 through the date of the information request. This type of information request has been used in the past to assist the EPA in determining whether a plant is in compliance with applicable standards under the CAA. Cayuga and Somerset responded to the EPA s information request in June 2009, and they are awaiting a response from the EPA regarding their submittal. At this time it is not possible to predict what impact, if any, this request may have on Cayuga and/or Somerset, their results of operation or their financial position.

On February 2, 2009, the Cayuga facility received a Notice of Violation from the New York State Department of Environmental Conservation that the facility had exceeded the permitted volume limit of coal ash that can be disposed of in the on-site landfill. Cayuga has met with and submitted a demonstration plan to the agency and discussions between the parties are ongoing. Cayuga is awaiting a response from the New York State Department of Environmental Conservation. While at this time it is not possible to predict what impact, if any, this matter may have on Cayuga, its results of operation or its financial position, based upon the discussions to date, the Company does not believe the impact will be material.

In June 2009, the Inter-American Commission on Human Rights of the Organization of American States (IACHR) requested that the Republic of Panama suspend the construction of AES Changuinola S.A. s hydroelectric project (Project) until the bodies of the Inter-American human rights system can issue a final decision on a petition (286/08) claiming that the construction violates the human rights of alleged indigenous communities. In July 2009, Panama responded by informing the IACHR that it would not suspend construction of the Project and requesting that the IACHR revoke its request. The IACHR heard arguments by the communities and Panama on the merits of the petition in November 2009, but has not issued a decision to date. The Company cannot predict Panama s response to any determination on the merits of the petition by the bodies of the Inter-American human rights system.

In July 2009, AES Energía Cartagena S.R.L. (AES Cartagena) received notices from the Spanish national energy regulator, Comisión Nacional de Energía (CNE), stating that AES Cartagena s revenues should be reduced by roughly the value of the free CO_2 allowances granted to AES Cartagena for 2007, 2008, and the first half of 2009, and that CNE intended to invoice AES Cartagena to recover that value, which CNE calculated as approximately 20 million ($29 million) for 2007-2008 and an amount to be determined for the first half of 2009. On September 17, 2009, AES Cartagena received invoices for 523,548 ($750,000) for 2007 and 19,907,248 ($29 million) for 2008. In October 2009, AES Cartagena filed an administrative appeal against both such invoices with the Spanish Ministry of Industry and also applied for a stay of its obligation to pay the invoices pending the hearing of that appeal. In November 2009, the appeal was unsuccessful and the application for stay was rejected. AES Cartagena subsequently filed an appeal with the Spanish Court. There can be no assurances that the judicial appeal will be successful. AES Cartagena has demanded indemnification from GDF-Suez in relation to the CNE invoices and any future such invoices under the long-term energy agreement (the Energy Agreement) with GDF-Suez. However, GDF-Suez has disputed that it is responsible for the CNE invoices under the Energy Agreement. Therefore, in September 2009, AES Cartagena initiated arbitration against GDF-Suez, seeking to recover the payments made to CNE and a determination that GDF-Suez is responsible for procuring and bearing the cost of CO_2 allowances that are required to offset the emissions of AES Cartagena s power plant, which is also in dispute between the parties. AES Cartagena believes it has meritorious claims and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In September 2009, the Public Defender s Office of the State of Rio Grande do Sul filed a class action against AES Sul in the 16th District Court of Porto Alegre, Rio Grande do Sul (District Court), claiming that AES Sul has been illegally passing PIS and COFINS taxes (taxes based on AES Sul s income) to consumers. According to ANEEL s Order No. 93/05, the federal laws of Brazil, and the Brazilian Constitution, energy companies such as AES Sul are entitled to highlight PIS and COFINS taxes in power bills to final consumers, as the cost of those taxes is included in the energy tariffs that are applicable to final consumers. Before AES Sul had

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been served with the action, the District Court dismissed the lawsuit in October 2009 on the ground that AES Sul had been properly highlighting PIS and COFINS taxes in consumer bills in accordance with Brazilian law. The Public Defender s Office is expected to appeal. If the dismissal is reversed and AES Sul does not prevail in the lawsuit and is ordered to cease recovering PIS and COFINS taxes pursuant to its energy tariff, its potential prospective losses could be approximately R$9.6 million ($6 million) per month, as estimated by AES Sul. In addition, if AES Sul is ordered to reimburse consumers, its potential retrospective liability could be approximately R$1.2 billion ($692 million), as estimated by AES Sul. AES Sul believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings if it is served with the action; however, there can be no assurances that it would be successful in its efforts. Furthermore, if AES Sul does not prevail in the litigation it will seek to adjust its energy tariff to compensate it for its losses, but there can be no assurances that it would be successful in obtaining an adjusted energy tariff.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders during the fourth quarter of 2009.

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PART II

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

On November 6, 2009, the Company entered into a stock purchase agreement (the Stock Purchase Agreement) with Terrific Investment Corporation (Investor), a wholly-owned subsidiary of China Investment Corporation (CIC), pursuant to which the Company agreed to issue and sell to Investor 125,468,788 shares of the Company s common stock for $12.60 per share, for an aggregate purchase price of $1.58 billion. Following the issuance of the shares of common stock, Investor s ownership in the Company s common stock will be approximately 15% percent of the Company s total outstanding shares of common stock on a fully diluted basis.

The closing of the sale of the shares of common stock of the Company to Investor is subject to certain closing conditions including, the receipt of various regulatory approvals and no occurrence of a material adverse change prior to closing with respect to the Company. The transaction is expected to close in the first half of 2010.

At the closing of the transaction, the Company and Investor would enter into a stockholder agreement (the Stockholder Agreement). Under the Stockholder Agreement, as long as Investor holds more than 5% of the outstanding shares of common stock of the Company, Investor will have the right to nominate one representative for election to the Board of Directors of the Company. In addition, until such time as Investor holds 5% or less of the outstanding shares of common stock, Investor has agreed to vote its shares in accordance with the recommendation of the Company on any matters submitted to a vote of the stockholders of the Company relating to the election of directors and compensation matters. Otherwise, Investor may vote such shares in its discretion. Further, under the Stockholder Agreement, Investor will be subject to a customary standstill restriction which generally prohibits Investor from purchasing additional securities of the Company beyond the level acquired by it under the Stock Purchase Agreement. In addition, Investor has agreed to a lock-up restriction such that Investor would not sell its shares for a period of 12 months following the closing, subject to certain exceptions. The standstill and lock-up restrictions also terminate at such time as Investor holds 5% or less of the outstanding shares of common stock. Investor will have certain registration rights and preemptive rights under the Stockholder Agreement with respect to its shares of common stock of the Company.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

None.

Market Information

Our common stock is currently traded on the New York Stock Exchange (NYSE) under the symbol AES. The closing price of our common stock as reported by the NYSE on February 19, 2010, was $12.18, per share. The Company repurchased 10,691,267 shares of its common stock in 2008 and did not repurchase any of its common stock in 2009 or 2007. The following tables set forth the high and low sale prices, and performance trends for our common stock as reported by the NYSE for the periods indicated:

	2009		2008	
Price Range of Common Stock	**High**	**Low**	**High**	**Low**
First Quarter	$ 9.48	$ 4.80	$ 21.99	$ 15.98
Second Quarter	11.64	5.62	20.34	16.85
Third Quarter	15.37	10.67	19.27	11.23
Fourth Quarter	15.44	12.50	11.28	6.40

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Performance Graph

THE AES CORPORATION

PEER GROUP INDEX/STOCK PRICE PERFORMANCE

Source: Bloomberg

We have selected the Standard and Poor s (S&P) 500 Utilities Index as our peer group index. The S&P 500 Utilities Index is a published sector index comprising the 32 electric and gas utilities included in the S&P 500.

The five year total return chart assumes $100 invested on December 31, 2004 in AES Common Stock, the S&P 500 Index and the S&P 500 Utilities Index. The information included under the heading Performance Graph shall not be considered filed for purposes of Section 18 of the Securities Exchange Act of 1934 or incorporated by reference in any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934.

Holders

As of February 19, 2010, there were approximately 7,906 record holders of our common stock, par value $0.01 per share.

Dividends

We do not currently pay dividends on our common stock. We intend to retain our future earnings, if any, to finance the future development and operation of our business. Accordingly, we do not anticipate paying any dividends on our common stock in the foreseeable future.

Under the terms of our Senior Secured Credit Facilities, which we entered into with a commercial bank syndicate, we have limitations on our ability to pay cash dividends and/or repurchase stock. In addition, under the terms of a guaranty we provided to the utility customer in connection with the AES Thames project, we are precluded from paying cash dividends on our common stock if we do not meet certain net worth and liquidity tests.

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Our project subsidiaries ability to declare and pay cash dividends to us is subject to certain limitations contained in the project loans, governmental provisions and other agreements to which our project subsidiaries are subject.

See the information contained under the caption Securities Authorized for Issuance under Equity Compensation Plans of the Proxy Statement for the 2010 Annual Meeting of Shareholders of the Registrant, which information is incorporated herein by reference.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected financial data as of the dates and for the periods indicated. You should read this data together with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements and the notes thereto included in Item 8 of this Form 10-K. The selected financial data for each of the years in the five year period ended December 31, 2009 have been derived from our audited Consolidated Financial Statements. Our historical results are not necessarily indicative of our future results.

Acquisitions, disposals, reclassifications and changes in accounting principles affect the comparability of information included in the tables below. Please refer to the Notes to the Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data of this Form 10-K for further explanation of the effect of such activities. Please also refer to Item 1A. Risk Factors of this Form 10-K and Note 24 Risks and Uncertainties to the Consolidated Financial Statements included in Item 8 of this Form 10-K for certain risks and uncertainties that may cause the data reflected herein not to be indicative of our future financial condition or results of operations.

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SELECTED FINANCIAL DATA

Statement of Operations Data	2009	2008	2007	2006	2005
	Year Ended December 31, (in millions, except per share amounts)				
Revenue	$ 14,119	$ 15,358	$ 13,014	$ 11,079	$ 9,894
Income from continuing operations	1,836	1,959	857	584	598
Income from continuing operations attributable to The AES Corporation, net of tax	729	1,189	454	147	319
Discontinued operations, net of tax	(71)	45	(549)	78	234
Extraordinary items, net of tax				22	
Cumulative effect of change in accounting principle, net of tax					(4)
Net income (loss) attributable to The AES Corporation	$ 658	$ 1,234	$ (95)	$ 247	$ 549
Basic (loss) earnings per share:					
Income from continuing operations attributable to The AES Corporation, net of tax	$ 1.09	$ 1.78	$ 0.68	$ 0.22	$ 0.49
Discontinued operations, net of tax	(0.10)	0.06	(0.82)	0.12	0.36
Extraordinary items, net of tax				0.03	
Cumulative effect of change in accounting principle, net of tax					(0.01)
Basic earnings (loss) per share	$ 0.99	$ 1.84	$ (0.14)	$ 0.37	$ 0.84
Diluted (loss) earnings per share:					
Income from continuing operations attributable to The AES Corporation, net of tax	$ 1.09	$ 1.76	$ 0.67	$ 0.22	$ 0.49
Discontinued operations, net of tax	(0.11)	0.06	(0.81)	0.12	0.35
Extraordinary items, net of tax				0.03	
Cumulative effect of change in accounting principle, net of tax					(0.01)
Diluted earnings (loss) per share	$ 0.98	$ 1.82	$ (0.14)	$ 0.37	$ 0.83

Balance Sheet Data:	2009	2008	2007	2006	2005
	December 31, (in millions)				
Total assets	$ 39,535	$ 34,806	$ 34,453	$ 31,274	$ 29,025
Non-recourse debt (long-term)	$ 12,642	$ 11,625	$ 11,025	$ 9,575	$ 9,996
Non-recourse debt (long-term) Discontinued operations	$ 222	$ 244	$ 305	$ 607	$ 779
Recourse debt (long-term)	$ 5,301	$ 4,994	$ 5,332	$ 4,790	$ 4,682
Cumulative preferred stock of a subsidiary	$ 60	$ 60	$ 60	$ 60	$ 60
Retained earnings (accumulated deficit)	$ 650	$ (8)	$ (1,241)	$ (1,093)	$ (1,340)
The AES Corporation stockholders equity	$ 4,675	$ 3,669	$ 3,164	$ 2,979	$ 1,583

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Overview of Our Business

We are a global power company. We operate two primary lines of business. The first is our Generation business, where we own and/or operate power plants to generate and sell power to wholesale customers such as utilities, other intermediaries and certain end-users. The second is our Utilities business, where we own and/or operate utilities to distribute, transmit and sell electricity to end-user customers in the residential, commercial, industrial and governmental sectors within a defined service area. Our Generation and Utilities businesses comprise approximately 45% and 55% of our consolidated revenue, respectively.

We are also continuing to expand our wind generation business and are pursuing additional opportunities in the renewable business including solar and climate solutions, which develops and invests in projects that generate greenhouse gas offsets and or other renewable projects. These initiatives are not material contributors to our operating results, but we believe that certain of these initiatives may become material in the future. For additional information regarding our Business, see Item 1. Business of this Form 10-K.

Our Organization and Segments. The management reporting structure is organized along our two lines of business (Generation and Utilities) and three regions: (1) Latin America & Africa; (2) North America; and (3) Europe, Middle East & Asia (collectively EMEA), each managed by a regional president. The financial reporting segment structure uses the Company s management reporting structure as its foundation and reflects how the Company manages the business internally. The Company applied the segment reporting accounting guidance, which provides certain quantitative thresholds and aggregation criteria, and the Company concluded that it has six reportable segments which include:

- Latin America Generation;
- Latin America Utilities;
- North America Generation;
- North America Utilities;
- Europe Generation;
- Asia Generation.

Corporate and Other. The Company s Europe Utilities, Africa Utilities and Africa Generation operating segments are reported within Corporate and Other because they do not meet the criteria to allow for aggregation with another operating segment or the quantitative thresholds that would require separate disclosure under segment reporting accounting guidance. Additionally, AES Wind Generation is managed within our North America region and the Company s climate solutions projects are managed within the region in which they are located. Despite the management of AES Wind Generation by the North America region and climate solutions projects within the regions, the operating results of AES Wind Generation and our climate solutions projects are reported within Corporate and Other because they do not meet the aggregation criteria to be combined into the respective region s Generation or Utilities segments or the quantitative thresholds that would require separate disclosure under segment reporting accounting guidance. None of these operating segments are currently material to our financial statement presentation of reportable segments, individually or in the aggregate. Corporate and Other also includes costs related to business development efforts, which with certain exceptions, the Company manages centrally through a development group, corporate overhead costs which are not directly associated with the operations of our six reportable segments and other intercompany charges such as self-insurance premiums which are fully eliminated in consolidation.

Key Drivers of Our Results of Operations. Our Generation and Utilities businesses are distinguished by the nature of their customers, operational differences, cost structure, regulatory environment and risk exposure. As a result, each line of business has slightly different drivers which affect operating results. Performance drivers for

our Generation businesses include, among other things, plant reliability and efficiency, power prices, volume, management of fixed and variable operating costs, management of working capital including collection of receivables, and the extent to which our plants have hedged their exposure to currency and commodities such as fuel. For our Generation businesses which sell power under short-term contracts or in the spot market, the most crucial factors are the current market price of electricity and the marginal costs of production. Growth in our Generation business is largely tied to securing new PPAs, expanding capacity in our existing facilities and building or acquiring new power plants. Performance drivers for our Utilities businesses include, but are not limited to, reliability of service; management of working capital, including collection of receivables; negotiation of tariff adjustments; compliance with extensive regulatory requirements; and in developing countries, reduction of commercial and technical losses. The operating results of our Utilities businesses are sensitive to changes in economic growth and weather conditions in areas in which they operate. In addition to these drivers, as explained below, the Company also has exposure to currency exchange rate fluctuations.

One of the key factors which affects our Generation business is our ability to enter into contracts for the sale of electricity and the purchase of fuel used to produce that electricity. Long-term contracts are intended to reduce the exposure to volatility associated with fuel prices in the market and the price of electricity by fixing the revenue and costs for these businesses. The majority of the electricity produced by our Generation businesses is sold under long-term contracts, or PPAs, to wholesale customers. In turn, most of these businesses enter into long-term fuel supply contracts or fuel tolling arrangements where the customer assumes full responsibility for purchasing and supplying the fuel to the power plant. While these long-term contractual agreements reduce exposure to volatility in the market price for electricity and fuel, the predictability of operating results and cash flows vary by business based on the extent to which a facility s generation capacity and fuel requirements are contracted and the negotiated terms of these agreements. Entering into these contracts exposes us to counterparty credit risk. For further discussion of these risks, see *Supplier and/or customer concentration may expose the Company to significant financial credit or performance risks.* in Item 1A. Risk Factors of this Form 10-K.

When fuel costs increase, many of our businesses are able to pass these costs on to their customers. Generation businesses with long-term contracts in place do this by including fuel pass-through or fuel indexing arrangements in their contracts. Utilities businesses can pass costs on to their customers through increases in current or future tariff rates. Therefore, in a rising fuel cost environment, the increased fuel costs for these businesses often result in an increase in revenue to the extent these costs can be passed through (though not necessarily on a one-for-one basis). Conversely, in a declining fuel cost environment, the decreased fuel costs can result in a decrease in revenue. Increases or decreases in revenue at these businesses that have the ability to pass through costs to the customer have a corresponding impact on cost of sales, to the extent the costs can be passed through, resulting in a limited impact on gross margin, if any. Although these circumstances may not have a large impact on gross margin, they can significantly affect gross margin as a percentage of revenue. As a result, gross margin as a percentage of revenue is a less relevant measure when evaluating our operating performance.

Global diversification also helps us to mitigate risk. Our portfolio employs a broad range of fuels, including coal, gas, fuel oil, water (hydroelectric power), wind and solar, which reduces the risks associated with dependence on any one fuel source. However, to the extent the mix of fuel sources enabling our generation capabilities in any one market is not diversified, the spread in costs of different fuels may also influence the operating performance and the ability of our subsidiaries to compete within that market. In certain cases, we may attempt to hedge fuel prices to manage this risk, but there can be no assurance that these strategies will be effective.

Our presence in mature markets helps mitigate the exposure associated with our businesses in emerging markets.

We also attempt to limit risk by hedging much of our interest rate and commodity risk, and by matching the currency of most of our subsidiary debt to the revenue of the underlying business. However, we only hedge a portion of our currency and commodity risks, and our businesses are still subject to these risks, as further described in Item 1A. Risk Factors of this Form 10-K, *We may not be adequately hedged against our exposure* *to changes in commodity prices or interest rates.* Continued commodity and power price volatility could impact our financial metrics to the extent this volatility is not hedged.

Due to our global presence, the Company has significant exposure to foreign currency fluctuations. The exposure is primarily associated with the impact of the translation of our foreign subsidiaries operating results from their local currency to U.S. dollars that is required for the preparation of our consolidated financial statements. Additionally, there is risk of transaction exposure when an entity enters into transactions, including debt agreements, in currencies other than their functional currency. These risks are further described in Item 1A. Risk Factors in this Form 10-K, *Our financial position and results of operations may fluctuate significantly due to fluctuations in currency exchange rates experienced at our foreign operations*. In 2009, changes in foreign currency exchange rates have had a significant impact on our operating results. In 2009, our gross margin decreased $137 million compared to 2008. The decrease included the unfavorable impact of $218 million due to changes in foreign currency exchange rates. In 2008, our gross margin increased $334 million compared to 2007, of which $105 million was due to favorable changes in foreign currency exchange rates. If the current foreign currency exchange rate volatility continues, our gross margin and other financial metrics could be affected.

Another key driver of our results is our ability to bring new businesses into commercial operations successfully. We currently have approximately 2,000 MW of projects under construction in six countries. Our prospects for increases in operating results and cash flows are dependent upon successful completion of these projects on time and within budget. However, as disclosed in Item 1A. Risk Factors of this Form 10-K, Our business is subject to substantial development uncertainties, construction is subject to a number of risks, including risks associated with site identification, financing and permitting and our ability to meet construction deadlines. Delays or the inability to complete projects and commence commercial operations can result in increased costs, impairment of assets and other challenges involving partners and counterparties to our construction agreements, PPAs and other agreements.

Our gross margin is also impacted by the fact that in each country in which we conduct business, we are subject to extensive and complex governmental regulations such as regulations governing the generation and distribution of electricity, and environmental regulations which affect most aspects of our business. Regulations differ on a country by country basis (and even at the state and local municipality levels) and are based upon the type of business we operate in a particular country, and affect many aspects of our operations and development projects. Our ability to negotiate tariffs, enter into long-term contracts, pass through costs related to capital expenditures and otherwise navigate these regulations can have an impact on our revenue, costs and gross margin. Environmental and land use regulations, including proposed regulation of carbon emissions, could substantially increase our capital expenditures or other compliance costs, which could in turn have a material adverse affect on our business and results of operations. For a further discussion of the Regulatory Environment, see Note 12 *Contingencies Environmental*, included in Item 8. Financial Statements and Supplementary Data, Item 1. *Business Regulatory Matters Environmental and Land Use Regulations* and Item 1A. Risk Factors *Risks Associated with Government Regulation and Laws* of this Form 10-K.

Other factors that can affect our financial results include gains and losses from the sales of businesses incurrence and release of legal, regulatory or tax reserves and asset impairment.

Key Drivers of Results in 2009

In 2009, the Company s gross margin and net income attributable to The AES Corporation decreased compared to the prior year, while cash flow from operations remained flat. Our results of operations were impacted in 2009 by factors including:

- the unfavorable impact of foreign currency translation losses on our international business operations due to the stronger U.S. dollar compared to most foreign currencies in 2009;

- lower net gains on the sale of investments;

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- lower fuel prices, which led to lower electricity prices and had a negative impact at our generation plants in New York, but benefited gross margin at our generation plants in Chile; and

- impairments recognized related to our businesses in the United Kingdom and Pakistan.

These events were offset in part from:

- improved operating performance and working capital management at certain of our businesses in Latin America and Asia;

- gains on foreign currency transactions compared to losses in the prior year; and

- a decrease in the effective tax rate in 2009 due, in part, to the release of valuation allowances at certain U.S. and Brazilian subsidiaries and non-taxable income recognized in Brazil as a result of the Programa de Recuperacao Fiscal (REFIS) program.

During the year, net cash provided by operating activities remained relatively flat at $2.2 billion compared to 2008. Please refer to *Consolidated Cash Flows Operating Activities* for further discussion.

To address and mitigate the challenges faced by the Company this year, we were able to partially offset the impact of unfavorable factors on revenue and gross margin through fuel and geographic diversification, operational improvements at certain businesses, asset recoveries and fixed cost reductions. An example of where lower spot electricity prices benefited the Company took place at our generation business operating in the central Chilean market. A decrease in contract and spot market rates contributed to lower revenue. However, gross margin improved as we were able to fulfill our obligations under electricity contracts with purchased energy rather than producing energy from less efficient plants in our portfolio. This mitigated in-part the negative impact that the lower electricity prices had on our generation plants in New York.

In 2010, we expect to face continued pressure on prices and demand at our businesses in New York and at certain of our European operations which may have an adverse impact on gross margin and net income attributable to The AES Corporation. In addition, our operating results in 2009 and 2008 included other income from a performance incentive bonus and gains from the sale of our Northern Kazakhstan business that will not recur in 2010. In 2009, we recognized income from the extinguishment of liabilities related to our participation in a tax amnesty program in Brazil which will not recur in 2010. We estimate that our effective tax rate in 2010 will be higher than our reported effective tax rates in 2009 and 2008. This is due, in part, to discrete factors that lowered the effective tax rates in 2009 and 2008 and an anticipated increase in U.S. taxes on distributions from certain non-U.S. subsidiaries in 2010. Management expects improved operating performance at certain businesses and growth from new businesses launched in 2009 or expected to launch operation in 2010 may lessen or offset the impact of these adverse factors on our operations; however, we expect if these favorable effects we anticipate do not occur or if other challenges described above impact our operations more than we currently anticipate, then these adverse factors may continue to present challenges to maintaining our gross margin, net income attributable to The AES Corporation and net cash provided by operating activities.

The following briefly describes the key changes in our reported revenue, gross margin, net income attributable to The AES Corporation, Adjusted Earnings per Share (a non-GAAP measure) and net cash provided by operating activities for the year ended December 31, 2009 compared to 2008 and 2007 should be read in conjunction with our *Consolidated Results of Operations and Segment Analysis* discussion within our *Management s Discussion and Analysis of Financial Condition*.

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Performance Highlights

	Year Ended December 31,		
	2009	2008	2007
		(in millions)	
Revenue	$ 14,119	$ 15,358	$ 13,014
Gross Margin	$ 3,495	$ 3,632	$ 3,298
Net Income (Loss) Attributable to The AES Corporation	$ 658	$ 1,234	$ (95)
Diluted Earnings per Share from Continuing Operations	$ 1.09	$ 1.76	$ 0.67
Adjusted Earnings Per Share (a non-GAAP measure)(1)	$ 1.08	$ 1.08	$ 0.94
Net Cash Provided by Operating Activities	$ 2,213	$ 2,161	$ 2,354

(1) See reconciliation and definition below under Non-GAAP Measure.

Year Ended December 31, 2009

Revenue decreased $1.2 billion, or 8%, to $14.1 billion in 2009 compared with $15.4 billion in 2008. Key drivers of the decrease included:

- the unfavorable impact of foreign currency of $997 million, largely driven by the Brazilian Real;
- decreases in volume at Uruguaiana due to the renegotiation of its power sales agreements in 2009 to reduce the energy volume sold, as well as in New York and Hungary and lower dispatch in Northern Ireland due to unfavorable gas prices compared to coal;
- the impact of lower spot and contract energy prices at our generation business in Chile;
- lower energy prices and volume at our generation businesses in the Dominican Republic; and
- partially offset by an increase in tariff rates at our utilities businesses in Latin America primarily reflecting the recovery of energy purchases that were passed through to our customers.

Gross margin decreased $137 million, or 4%, to $3.5 billion in 2009 compared with $3.6 billion in 2008. Key drivers of the decrease included:

- the unfavorable impact of foreign currency of $218 million, largely driven by the Brazilian Real;
- lower energy prices and higher purchased energy costs at our generation businesses in the Dominican Republic and Argentina;
- increased pension costs in Brazil and the U.S.;
- lower volume in New York due to lower spot market rates;

- partially offset by improved operating performance at our generation businesses in Chile and the Philippines;

- higher tariffs in Brazil and El Salvador; and

- bad debt recoveries and a reduction in bad debt expense in Brazil.

Net income attributable to The AES Corporation decreased $576 million to $658 million in 2009. Key drivers of the decrease included:

- a gain recognized in 2008 from the sale of two wholly-owned subsidiaries in Northern Kazakhstan partially offset by a performance incentive bonus recognized in 2009 for management services provided to these subsidiaries and a settlement upon termination of the management agreement in 2009;

- the reduction in gross margin in 2009 as described above;

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- higher impairment expenses in 2009 as a result of an impairment of goodwill at our business in Kilroot, and an impairment recognized on our assets in Pakistan which is reflected in discontinued operations, offset by a decline in long-lived asset impairment from 2008;

- partially offset by a reduction in foreign currency transaction losses on net monetary position as a result of reduced losses at our businesses in Chile and the Philippines;

- a reduction in interest expense due primarily to lower interest rates and debt balances in Brazil and favorable foreign currency translation; and

- lower income tax expenses driven in part by lower pre-tax income and a decrease in the effective tax rate from 29% in 2008 to 26% in 2009 due, in part, to tax benefits recorded in 2009 upon the release of valuation allowances at U.S. and Brazilian subsidiaries, $165 million of non-taxable income recognized in Brazil as a result of the REFIS program in 2009 and an increase in U.S. taxes on distributions from the Company s primary holding company in the second quarter of 2008.

In 2008, the $905 million gain recognized on the sale of our two Northern Kazakhstan businesses had a significant impact on net income attributable to The AES Corporation. In 2009, the Company recognized a performance incentive bonus of $80 million in the first quarter for management services provided to these sold businesses, reflected as other income. Additionally, in the second quarter of 2009, the Company recognized an additional gain on the sale of the businesses of $98.5 million upon the termination of the management agreement. While the Company engages in the sale of assets and businesses from time to time, the gain or loss recognized in any such sale will depend on a number of factors related to the asset or business that may be sold. Therefore, the Company does not believe that the decline in net income between 2008 and 2009 represents a trend. All of the amounts related to our two Northern Kazakhstan businesses were reported in continuing operations and will not recur in 2010 or future years.

Net cash provided by operating activities increased $52 million, or 2%, to $2.2 billion in 2009 compared with $2.2 billion in 2008. Please refer to *Consolidated Cash Flows Operating Activities* for further discussion.

Year Ended December 31, 2008

Revenue increased 18% to $15.4 billion in 2008 compared with $13.0 billion in 2007. Key drivers of the increase included:

- higher generation rates in Latin America;

- the favorable impact of foreign currency of $443 million; and

- utility tariffs and volume.

Gross margin increased 10% to $3.6 billion in 2008 compared with $3.3 billion in 2007. Key drivers of the increase included:

- higher generation rates in Latin America;

- favorable foreign currency impact of $105 million;

- utility volume and tariff; and

partially offset by an increase in fixed costs associated with allowances for bad debts and higher purchased energy costs, primarily in Brazil and Cameroon.

Net income attributable to The AES Corporation increased $1.3 billion to $1.2 billion in 2008 from a net loss attributable to The AES Corporation of $95 million in 2007. The 2008 results included the following amounts, after taxes and noncontrolling interest unless otherwise noted:

the recognition of a gain on the sale of assets in Kazakhstan of $905 million;

partially offset by additional tax expense of $144 million related to the repatriation of a portion of the Kazakhstan sale proceeds;

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impairment charges of $83 million related to asset impairments in Brazil, South Africa and certain liquified natural gas (LNG) and other development efforts; and

a loss of $34 million related to corporate debt restructuring and an increase in foreign currency transaction losses of $209 million.
The 2007 results included the following amounts, after taxes and noncontrolling interest, unless otherwise noted:

a loss from the sale of C.A. La Electricidad de Caracas (EDC) of $680 million which was reflected in discontinued operations;

asset impairment charges of $224 million related to Uruguaiana and AgCert;

a gain of $101 million related to the acquisition of a leasehold interest at the Company s Eastern Energy business in New York and the recovery of certain tax assets in Latin America;

a $55 million loss related to a corporate debt restructuring; and

the remaining increase was primarily a result of improved performance in 2008.
In both 2008 and 2007, the gain or loss recognized on the sale of a business had a significant impact on net income attributable to The AES Corporation during the applicable period. However, while the Company engages in the sale of assets from time to time, the amount of gain or loss that would be recognized in such sale, if any, will depend on a number of factors related to any asset or business that may be sold. Therefore, the Company does not expect that the increase in net income attributable to The AES Corporation which occurred between 2007 and 2008 will continue in future periods.

Net cash from operating activities decreased $193 million, or 8%, to $2.2 billion in 2008 compared with $2.4 billion in 2007. Excluding the decrease in net cash provided by operating activities from EDC in Venezuela, which was sold in May 2007, net cash provided by operating activities would have decreased $37 million. Key drivers of the decrease included:

increased employer pension contributions at our U.S. and foreign subsidiaries; and

an increase in regulatory assets related to future recoverable purchased energy costs in Brazil;

partially offset by a decrease in cash used by a Brazilian subsidiary to pay income taxes in 2008 as a result of tax credits used as the primary payment method in 2008; and

improved operations in Latin America and Europe as well as our Africa businesses reported in the Corporate and Other segment.
Non-GAAP Measure

We define adjusted earnings per share (Adjusted EPS) as diluted earnings per share from continuing operations excluding gains or losses of the consolidated entity due to (a) mark-to-market amounts 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. The GAAP measure most comparable to Adjusted EPS is diluted earnings per share from continuing operations. AES believes that Adjusted EPS better reflects the underlying business performance of the Company and is considered in the

Company s internal evaluation of financial performance. Factors in this determination include the variability due to mark-to-market gains or losses related to derivative transactions, currency gains or losses, losses due to impairments and strategic decisions to dispose or acquire business interests or retire debt which affect results in a given period or periods. Adjusted EPS should not be construed as an alternative to diluted earnings per share from continuing operations, which is determined in accordance with GAAP.

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Reconciliation of Adjusted Earnings Per Share	Year Ended December 31, 2009	2008	2007
Diluted earnings per share from continuing operations	$ 1.09	$ 1.76	$ 0.67
Derivative mark-to-market (gains)/losses[(1)]	0.02	0.05	0.04
Currency transaction (gains)/losses[(2)]	(0.05)	0.16	(0.03)
Disposition/acquisition (gains)/losses	(0.19)[(3)]	(1.27)[(5)]	(0.18)[(8)]
Impairment losses	0.21[(4)]	0.13[(6)]	0.36[(9)]
Debt retirement (gains)/losses		0.25[(7)]	0.08[(10)]
Adjusted earnings per share	$ 1.08	$ 1.08	$ 0.94

(1) Derivative mark-to-market (gains)/losses were net of income tax per share of $0.01, $0.00 and ($0.02) in 2009, 2008 and 2007, respectively.

(2) Unrealized foreign currency transaction (gains)/losses were net of income tax per share of $0.01, $0.00 and $0.02 in 2009, 2008 and 2007, respectively.

(3) Amount includes: Kazakhstan gain of $98 million, or $0.15 per share, related to the termination of a management agreement as well as a gain of $13 million, or $0.02 per share, related to the reversal of a withholding tax contingency. There were no taxes associated with any of these transactions. In addition, there was a gain on sale associated with the shutdown of the Hefei plant in China of $14 million, or $0.02 per share, net of noncontrolling interest and income tax. There were no taxes associated with any of these transactions.

(4) Amount includes: Goodwill impairments at Kilroot of $118 million, or $0.18 per share, and in the Ukraine of $4 million, or $0.01 per share; write-off of development project costs in Latin America and Asia of $19 million ($11 million net of noncontrolling interests, or $0.01 per share) and an impairment of $10 million, or $0.01 per share, of the Company s investment in a company developing blue gas (coal to gas) technology. There was no income tax impact associated with any of these transactions.

(5) Amount includes: Net gain on Kazakhstan sale of $905 million, or $1.31 per share, and net loss on sale of subsidiary interests in Gener of $31 million, or $0.04 per share. There was no income tax impact associated with these transactions.

(6) Amount includes: Impairment charges primarily associated with development projects in North America of $75 million ($34 million net of noncontrolling interests and income tax, or $0.06 per share); Uruguaiana asset write-down of $36 million ($17 million net of noncontrolling interest, or $0.02 per share); South Africa peaker development cost write-off of $31 million ($28 million net of income tax, or $0.04 per share) and a nontaxable impairment of the Company s investment in blue gas (coal to gas) technology of $10 million, or $0.01 per share. Impairment losses are net of an income tax benefit of $0.02 per share in 2008.

(7) Amount includes: $55 million ($34 million net of income tax, or $0.05 per share) loss on the retirement of Parent Company debt; $131 million, or $0.19 per share, which represented the tax impact on the repatriation of a portion of the Kazakhstan sale proceeds that were used to fund the early retirement of Parent Company debt; and $14 million ($9 million net of income tax, or $0.01 per share) of debt refinancing at IPALCO. Debt Retirement (gains)/losses are net of an income tax benefit of $0.04 per share in 2008.

(8) Amount includes: Net gain on sale of subsidiary interests in Gener of $125 million, or $0.18 per share. There is no income tax impact associated with this transaction.

(9) Amount includes: Uruguaiana nontaxable asset write-down of $352 million ($163 million net of noncontrolling interest, or $0.24 per share); AgCert investment impairment and receivable write-off of $67 million ($61 million net of income tax, or $0.09 per share); asset impairment charges in North America for a total of $35 million ($21 million net of income tax, or $0.03 per share). Impairment losses are net of an income tax benefit of $0.03 per share in 2007.

(10) Amount includes: Loss on retirement of Parent Company debt of $92 million ($55 million net of income tax, or $0.08 per share). Debt Retirement (gains)/losses are net of an income tax benefit of $0.05 per share in 2007.

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Management s Priorities

Management continues to focus on the following priorities:

Closing the share issuance to CIC On November 6, 2009, we entered into a stock purchase agreement (the Stock Purchase Agreement) with Terrific Investment Corporation (Investor), a wholly-owned subsidiary of China Investment Corporation (CIC), pursuant to which the Company agreed to issue and sell to Investor 125,468,788 shares of the Company s common stock for $12.60 per share, for an aggregate purchase price of $1.58 billion. Following the issuance of the shares of common stock, Investor s ownership in the Company s common stock will be approximately 15% percent of the Company s total outstanding shares of common stock on a fully diluted basis.

The closing of the sale of the shares of common stock of the Company to Investor is subject to certain closing conditions. These closing conditions include the receipt of requisite regulatory approvals, and there being no material adverse change prior to closing with respect to the Company. The transaction is expected to close in the first half of 2010;

Improvement of operations in the existing portfolio;

Completion of approximately 2,000 MW construction program on time and within budget. During 2009, the Company stopped construction on its Campiche plant, as further described in *Key Trends and Uncertainties Operational Challenges* below;

Prudent deployment of capital to fund growth initiatives of the Company through greenfield development or mergers and acquisitions;

Maximizing the use of cash, including establishment of low-cost development options, reducing debt and increasing cash balances; and

Integration of new projects. During 2009, the following projects commenced commercial operations:

Project	Location	Fuel	Gross MW	AES Equity Interest (Percent, Rounded)
Dibamba	Cameroon	Heavy Fuel Oil	86	56%
Guacolda 3[1]	Chile	Coal	152	35%
Santa Lidia	Chile	Diesel	130	71%
Huanghua I[2]	China	Wind	49	49%
InnoVent[3]	France	Wind	26	40%
Amman East	Jordan	Gas	380	37%
Kilroot OCGT	United Kingdom	Gas	80	