AES CORP
Form 10-K
February 26, 2010
Table of Contents

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

Table of Contents

THE AES CORPORATION

FISCAL YEAR 2009 FORM 10-K

TABLE OF CONTENTS

Table of Contents

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

1

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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

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

($ in billions)

Gross Margin

($ 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

Table of Contents

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.

Table of Contents

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)

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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		

Table of Contents

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		

16

Table of Contents

(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.

Table of Contents

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 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.

Table of Contents

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

Table of Contents

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 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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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 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

Table of Contents

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;

29

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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 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.

Table of Contents

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

Table of Contents

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

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

Table of Contents

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.

Table of Contents

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;

Table of Contents

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;

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 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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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;

Table of Contents

- 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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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;

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

Table of Contents

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.

Table of Contents

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 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.

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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 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.

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

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.

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

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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;

- 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*.

Table of Contents

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;

Table of Contents

- 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;

Table of Contents

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.

Table of Contents

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.

Table of Contents

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	99%
Armenia Mountain	USA PA	Wind	101	100%

(1) Guacolda is an equity method investment indirectly held by AES through Gener. The AES equity interest reflects the 29% noncontrolling interests in Gener.

(2) Huanghua is an equity method investment of AES.

(3) InnoVent is an equity method investment of AES.

Completing Announced Asset Sales In December 2009, we reached agreements to sell our entire interests in our two generation businesses in Pakistan and our entire interest in our business in Oman for aggregate gross proceeds, before purchase price adjustments, of approximately $200 million. Impairment charges of $150 million, or $105 million net of noncontrolling interest, was recognized in the fourth quarter of 2009 representing the amount by which the net book value of the businesses exceeded the fair value for the Pakistan businesses. These transactions are subject to customary purchase prices adjustments and approvals and are expected to close in the first half of 2010. Until the transactions close, the businesses will be reported as discontinued operations in our consolidated statements of operations.

Key Trends and Uncertainties

Operational Challenges

Our operations continue to face many risks as discussed in Item 1A. Risk Factors of this Form 10-K. We continue to monitor our operations and address challenges as they arise.

As discussed in Item 1A. Risk Factors Risks Associated with our Operations *Our acquisitions may not perform as expected* of this Form 10-K, the Company evaluated its businesses through the completion of the annual goodwill impairment test as of October 1, 2009 and concluded that impairment existed at certain of our businesses in the United Kingdom and the Ukraine. As of December 31, 2009 the book value of goodwill related to these businesses was written off as a result of impairment charges of $122 million recognized in the fourth quarter.

During the past year, the Company has successfully completed a number of construction projects, totaling approximately 1,000 MW, on schedule, including Amman East in Jordan, Guacolda 3 and Santa Lidia in Chile, Kilroot OCGT in the United Kingdom, Huanghua I in China, InnoVent and St. Patrick in France, Dibamba in Cameroon and Armenia Mountain in the U.S. However, as discussed in Item 1A. Risk Factors Risks Associated with our Operations *Our business is subject to substantial development uncertainties* of this Form 10-K, our development projects are subject to uncertainties. 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, although there could be further delays in the completion of the project and commencement of commercial operations. 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, 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.

Global Recession

The global economic slowdown has caused unprecedented market illiquidity, widening credit spreads, volatile currencies, fluctuating fuel prices and increased counterparty credit risk each of which could impact our operations.

Table of Contents

Despite these challenges, management continues to believe that the Company can meet its near-term liquidity requirements through a combination of existing cash balances, cash provided by operating activities, financings, and, if needed, borrowings under its secured facility. Although there can be no assurance due to the challenging times currently faced by financial institutions, management believes that the participating banks under its facility will be able to meet their funding commitments.

The Company is subject to credit risk, which includes risk related to the ability of counterparties (such as parties to our PPAs, fuel supply agreements, our hedging agreements and other contractual arrangements) to deliver contracted commodities or services at the contracted price or to satisfy their financial or other contractual obligations. While counterparty credit risk has increased in the current crisis and there can be no assurances regarding the future, the Company has not suffered any material effects related to its counterparties during 2009.

The Company seeks business acquisitions as one of its growth strategies. We have achieved significant growth in the past as a result of several business acquisitions, which also resulted in the recognition of goodwill. As noted in Item 1A. Risk Factors, there is always a risk that *Our acquisitions may not perform as expected.* The benefits of goodwill are typically realized through the future operating results of an acquired business.

Management believes that the recoverability of goodwill is positively correlated with the economic environments in which our acquired businesses operate and a severe economic downturn could negatively impact the recoverability of goodwill. Also, the evolving environmental regulations around the globe continue to increase the operating costs of our generation businesses. In extreme situations, the environmental regulations could even make a once profitable business, uneconomic. In addition, most of our generation businesses have a finite life and as the acquired businesses reach the end of their finite lives, the carrying amount of goodwill is gradually recovered through their periodic operating results. The accounting guidance, however, prohibits a systematic amortization of goodwill and rather requires an annual impairment evaluation. Thus, as some of our acquired businesses approach the end of their lives, they may incur goodwill impairment charges even if there are no discrete adverse changes in the economic environment.

As part of the 2009 annual goodwill impairment evaluation, the Company noted three businesses with an aggregate goodwill balance of $202 million, whose fair values were not higher than their carrying values by more than 10%. It is possible in the future we may incur further goodwill impairment charges on these businesses or even other businesses whose fair values currently exceed their carrying values by more than 10% if any of the following events occur: a significant adverse change in business climate or legal factors, an adverse action or assessment by a regulator, sale of assets at below book value, unanticipated competition, a loss of key personnel, acquisitions not performing as expected, changing environmental regulations that significantly increase the cost of doing business, or the businesses reach the end of their finite lives. The likelihood of the occurrence of these events may increase because of the credit crisis and deteriorating global macroeconomic conditions.

The global economic slowdown could also result in a decline in the value of our assets including those at the businesses we operate, our equity investments and projects under development, which could result in asset impairments that could be material to our operations. We continue to monitor our projects and businesses as needed. A decline in asset value could also lead to a material increase in our obligations. For instance certain subsidiaries have defined benefit pension plans. The Company periodically evaluates the value of the pension plan assets to ensure that they will be sufficient to fund their respective pension obligations. In 2009, compared to the year ended December 31, 2008, we experienced an increase in contribution requirements and net periodic pension costs (pension expense) as a result of a decrease in pension plan asset values and an increase in the associated plan obligations at December 31, 2008. In 2010, although we expect cash contribution requirements to decrease from 2009 levels, contributions and pension expenses are expected to exceed 2008 levels. As of December 31, 2009, we expect the Company to make future employer contributions to its defined benefit pension plans in 2010 of approximately $179 million, of which $27 million will be made to its U.S. plans and $152 million to foreign plans, primarily in Brazil (subject to changes in foreign currency exchange rates), compared to employer contributions made in 2009 of $209 million, of which $21 million were made to

U.S. plans and $188 million to foreign plans. In Brazilian real (R$) contributions for our subsidiaries in Brazil are expected to decrease from R$348 million in 2009 to R$245 million in 2010. Pension expense in 2010 is currently estimated at $140 million (subject to changes in foreign currency exchange rates) compared to $138 million in 2009. Expense at our subsidiaries in Brazil, in local currency, is expected to be R$169 million in 2010 compared to R$176 million in 2009. See Item 1A. Risk Factors, *Some of our subsidiaries participate in defined benefit pension plans and their net pension plan obligations may require additional significant contribution* of this Form 10-K.

In addition, as described in Overview of Our Business, volatility in foreign currency exchange rates has had an impact on the Company s financial results. If the current volatility in foreign currencies continues, our gross margin and other financial metrics could be adversely affected. It is also possible that commodity or power price volatility could impact our financial metrics as further described in Overview of Our Business and Item 7A. Quantitative and Qualitative Disclosures About Market Risk *Commodity Price Risk* of this Form 10-K.

In the event that global economic conditions deteriorate further, or continue for a prolonged period, there could be a material adverse impact on the Company. The Company could be materially affected if such events or other events occur such that participating lenders under its secured facility fail to meet their commitments, or the Company is unable to access the capital markets on favorable terms or at all, or is unable to raise funds through the sale of assets, or is otherwise unable to finance or refinance its activities, or if capital market disruptions result in increased borrowing costs (including with respect to interest payments on the Company s variable rate debt). The Company could also be adversely affected if the foregoing effects are exacerbated or general economic or political conditions in the markets where the Company operates deteriorate, resulting in a reduction in cash flow from operations, a reduction in the availability and/or an increase in the cost of capital, a reduction in the value of currencies in these markets relative to the U.S. dollar (which could cause currency losses), an increase in the price of commodities used in our operations and construction, or if the value of its assets remain depressed or decline further. Any of the foregoing events or a combination thereof could have a material impact on the Company, its results of operations, liquidity, financial covenants, and/or its credit rating.

Regulatory Environment

The Company faces certain risks and uncertainties related to numerous environmental laws and regulations, including potential GHG legislation or regulations, and actual or potential laws and regulations pertaining to water discharges, waste management (including disposal of coal combustion by-products), and certain air emissions, such as SO_2, NO_x, particulate matter and mercury. Such risks and uncertainties include risks and uncertainties related to increased capital expenditures or other compliance costs which could have a material adverse effect on certain of our U.S. or international subsidiaries and our consolidated results of operations.

The Company continues to assess the possible need for capital expenditures associated with international, federal, regional and state regulation of GHG emission from electric power generation facilities. As discussed in Item 1. Business-Regulatory Matters-Environmental and Land Use Regulations of this Form 10-K, 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 in the next several years.

As discussed in Item 1. Business-Regulatory Matters-Environmental and Land Use Regulations of this Form 10-K, in 2009, the Company s subsidiaries operated businesses which had total approximate CO_2 emissions of 74.2 million metric tonnes (ownership adjusted). Approximately 39.7 million metric tonnes of the 74.2 million metric tonnes were emitted in the United States, and approximately 9.7 million metric tonnes were emitted in U.S. states participating in RGGI. There is substantial uncertainty with respect to whether U.S. federal GHG legislation will be enacted into law and whether the EPA will regulate GHG emissions and there is additional uncertainty regarding the final provisions and implementation of any potential U.S. federal GHG legislation or any EPA rules regulating GHG emissions. In light of these uncertainties, the Company cannot accurately predict the impact on its consolidated results of operations or financial condition from potential U.S.

Table of Contents

federal GHG legislation or EPA regulation of GHG emissions or make a reasonable estimate of the potential costs to the Company associated with any such legislation or regulation; however, the impact from any such legislation or regulation could have a material adverse effect on certain of our U.S. subsidiaries and on the Company and its consolidated results of operations and financial condition.

At this time, other than with regard to the RGGI, the Company cannot estimate the costs of compliance with U.S. state CO_2 emissions reductions legislation or initiatives, due to the fact that these state or regional proposals are in earlier stages of development than RGGI and any final regulations or legislation, if adopted, could vary drastically from current proposals. 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 the future, the possible impact on our U.S. subsidiaries from any future federal GHG legislation or regulations or any regional or state proposals to regulate and reduce GHG emissions, if enacted, will depend on a number of factors, including but not limited to the degree and timing of reductions of GHG emissions required under any such legislation or regulations, the price and availability of offsets or emissions allowances, the extent to which our subsidiaries would be entitled to receive GHG emissions allowances without having to purchase them, the quantity of allowances which our subsidiaries would have to purchase, our subsidiaries ability to recover or pass through costs incurred to comply with any compliance options, whether federal GHG legislation will preempt state programs or preempt the EPA from regulating GHG emissions, the availability and costs of carbon control technology, the benefits to our renewable businesses, if any, and the benefits to our GHG Emissions Reduction Projects from potentially increased demand for GHG offset credits or allowances.

With respect to our operations outside the United States, certain of the businesses operated by the Company s subsidiaries are subject to compliance with EU ETS and the Kyoto Protocol in certain countries and other country-specific programs to regulate GHG emissions. 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 because of, among other factors, the cost of GHG emission allowances and/or the ability of our businesses to pass the cost of purchasing such allowances on to customers or counterparties. However, as discussed in Item 1. Business Regulatory Matters Environmental and Land Use Regulations of this Form 10-K, in the event that such counterparties or regulatory authorities challenge our ability to pass these costs on, and one such counterparty is currently making such a challenge, there can be no assurance that the Company and/or the relevant subsidiary will prevail, or that the cost and burden associated with any such dispute will not be significant. The Kyoto Protocol is currently expected to expire at the end of 2012, and 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 Kyoto, 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 other successor agreements will have a material adverse effect on the Company s consolidated results of operations, financial condition and cash flows in future periods.

Table of Contents

The Company also continues to assess the possible need for capital expenditures associated with international, federal and state regulation of emissions of SO_2, NO_x, PM and mercury, and federal regulation of fly ash and other forms of CCB. As discussed in Item 1. Business-Regulatory Matters-Environmental and Land Use Regulations of this Form 10-K, the EPA may issue new regulations with respect to these air emissions and CCB. Although most of the Company s U.S. coal-fired plants have advanced pollution control technologies, future EPA regulations concerning emissions of SO_2, NO_x, PM and mercury may require such plants to incur additional capital expenditures to improve such control technologies or to acquire new pollution control technologies. Also, as discussed in Item 3. Legal Proceedings in this Form 10-K, additional capital expenditures may be required by IPL in connection with a Notice of Violation (NOV) from the EPA. In addition, as discussed in Item 1. Business-Regulatory Matters-Environmental and Land Use Regulations of this Form 10-K, future EPA regulations of CCB may require certain subsidiaries of the Company to incur additional capital expenditures with respect to the processing and disposal of CCB. The capital expenditures required to comply with future EPA regulations or any EPA NOVs or enforcement actions cannot be estimated.

Recent Events

In November 2009, our Brazilian subsidiary, Southern Electric Brasil Participações LTDA. (SEB), entered into a share purchase and sale agreement with Andrade Gutierrez Concessões S.A. and an affiliated company (jointly referred to as, AG) for the sale of SEB s shares in Companhia Energética de Minas Gerais (CEMIG). In consideration for SEB s shares in CEMIG, AG will pay to SEB a total purchase price equal to the sum of (i) $25 million plus (ii) the assumption by AG of SEB s debt (the BNDES Loan) with Banco Nacional de Desenvolvimento Econômico e Social (BNDES). The sale is subject to the resolution of all outstanding debts and claims relating to the BNDES Loan and is contingent upon SEB obtaining a full release from any claims of BNDES, the restructuring of the BNDES Loan and the ratification of the settlement by the judicial system.

On January 1, 2010, North Rhins, a 22 MW wind generation facility located in Scotland, commenced commercial operations. Additionally, on February 11, 2010, Nueva Ventanas, a 270 MW coal-fired generation plant located in Chile commenced commercial operations.

Table of Contents

Consolidated Results of Operations

Results of operations	2009	2008	2007	$ change 2009 vs. 2008	$ change 2008 vs. 2007
	Year Ended December 31, (in millions, except per share amounts)				
Revenue:					
Latin America Generation	$ 3,651	$ 4,468	$ 3,515	$ (817)	$ 953
Latin America Utilities	6,092	5,907	5,168	185	739
North America Generation	1,940	2,234	2,169	(294)	65
North America Utilities	1,068	1,079	1,052	(11)	27
Europe Generation	720	1,096	909	(376)	187
Asia Generation	643	553	315	90	238
Corporate and Other[(1)]	5	21	(114)	(16)	135
Total Revenue	$ 14,119	$ 15,358	$ 13,014	$ (1,239)	$ 2,344
Gross Margin:					
Latin America Generation	$ 1,357	$ 1,398	$ 957	$ (41)	$ 441
Latin America Utilities	918	886	864	32	22
North America Generation	477	660	702	(183)	(42)
North America Utilities	239	261	314	(22)	(53)
Europe Generation	189	260	240	(71)	20
Asia Generation	179	67	82	112	(15)
Corporate and Other[(2)]	136	100	139	36	(39)
General and administrative	(345)	(371)	(378)	26	7
Interest expense	(1,515)	(1,803)	(1,755)	288	(48)
Interest income	348	519	489	(171)	30
Other expense	(111)	(161)	(253)	50	92
Other income	466	377	358	89	19
Gain on sale of investments	131	909		(778)	909
(Loss) gain on sale of subsidiary stock		(31)	134	31	(165)
Goodwill impairment	(122)			(122)	
Asset impairment expense	(25)	(175)	(408)	150	233
Foreign currency transaction (losses) gains on net monetary position	33	(184)	29	217	(213)
Other non-operating expense	(12)	(15)	(57)	3	42
Income tax expense	(599)	(771)	(676)	172	(95)
Net equity in earnings of affiliates	92	33	76	59	(43)
Income from continuing operations	1,836	1,959	857	(123)	1,102
Income from operations of discontinued businesses	69	67	161	2	(94)
Gain (loss) from disposal of discontinued businesses	(150)	6	(661)	(156)	667
Net income	1,755	2,032	357	(277)	1,675
Noncontrolling interests:					
Income from continuing operations attributable to noncontrolling interests	(1,107)	(770)	(403)	(337)	(367)
Income from discontinuing operations attributable to noncontrolling interests	10	(28)	(49)	38	21
Net income (loss) attributable to The AES Corporation	$ 658	$ 1,234	$ (95)	$ (576)	$ 1,329
Per Share Data:					
Basic income per share from continuing operations	$ 1.09	$ 1.78	$ 0.68	$ (0.69)	$ 1.10
Diluted income per share from continuing operations	$ 1.09	$ 1.76	$ 0.67	$ (0.67)	$ 1.09

(1) Corporate and Other includes revenue from the Company s Europe Utilities, Africa Utilities, Africa Generation and renewables initiatives and inter-segment eliminations of revenue related to transfers of electricity from Tietê (generation) to Eletropaulo (utility) in Latin America.

(2) Total Corporate and Other expenses includes the gross margin from our generation and utilities businesses in Africa, our utilities businesses in Europe, AES Wind Generation and other renewables initiatives, development costs, and certain inter-segment eliminations, primarily corporate charges for self insurance premiums.

Table of Contents

Segment Analysis

Latin America Generation

The following table summarizes revenue and gross margin for our Generation segment in Latin America for the periods indicated:

	For the Years Ended December 31,				
	2009	2008	2007	% Change 2009 vs. 2008	% Change 2008 vs. 2007
	($ s in millions)				
Latin America Generation					
Revenue	$ 3,651	$ 4,468	$ 3,515	-18%	27%
Gross Margin	$ 1,357	$ 1,398	$ 957	-3%	46%

Fiscal Year 2009 versus 2008

Excluding the unfavorable impact of foreign currency translation of $181 million in Brazil and Argentina, generation revenue decreased $636 million, or 14%, from the previous year primarily due to lower spot and contract prices at Gener of $295 million, lower volume at Uruguaiana of $227 million as a result of the renegotiation of its power sales agreements in 2009 to reduce the energy volume sold, and lower energy prices and volume at our businesses in the Dominican Republic of $174 million. These decreases were partially offset by fewer outages in 2009 at Gener and at our businesses in Argentina of $100 million and higher prices of energy sold at Tiete of $66 million.

Excluding the unfavorable impact of foreign currency translation of $94 million in Brazil and Argentina, generation gross margin increased $53 million, or 4%, from the previous year primarily due to higher prices of energy sold at Tiete of $66 million, fewer outages in 2009 at Gener and at our businesses in Argentina of $60 million, lower diesel consumption, partially offset by higher energy purchases and higher gas consumption at Gener of $47 million, lower volume of energy purchased at Uruguaiana of $44 million as a result of the renegotiated power sales agreements and the favorable impact at Uruguaiana of a decrease in bad debt expense of $28 million as a result of the renegotiated power sales agreements. These increases were partially offset by the unfavorable impact of lower energy prices at our businesses in the Dominican Republic of $75 million, lower volume and energy prices of $66 million at our businesses in Argentina, higher purchased energy prices at Uruguaiana of $48 million and higher fuel and higher purchased energy at Panama of $48 million.

Even though generation revenue declined by 18%, gross margin decreased 3%. This was primarily due to reduced energy purchases, fewer outages and lower bad debt expense.

Fiscal Year 2008 versus 2007

Excluding the favorable impact of foreign currency translation of $77 million, generation revenue increased $876 million, or 25% from the previous year primarily due to higher contract and spot prices and higher volume at Gener in Chile and our businesses in Argentina of approximately $508 million and $188 million, respectively, higher contract and spot prices at our businesses in the Dominican Republic of approximately $132 million and higher spot prices at our businesses in Panama of approximately $45 million.

Excluding the favorable impact of foreign currency translation of $44 million, generation gross margin increased $397 million, or 41%, from the previous year primarily due to higher contract and spot prices and higher volume at Gener and our businesses in Argentina of approximately $318 million, higher contract and spot prices at our businesses in the Dominican Republic of approximately $86 million and higher spot prices at our businesses in Panama of approximately $30 million. These increases were partially offset by higher purchased energy prices of approximately $57 million at Uruguaiana in Brazil.

Table of Contents

Latin America Utilities

The following table summarizes revenue and gross margin for our Utilities segment in Latin America for the periods indicated:

	For the Years Ended December 31,				
	2009	2008	2007	% Change 2009 vs. 2008	% Change 2008 vs. 2007
	($ s in millions)				
Latin America Utilities					
Revenue	$ 6,092	$ 5,907	$ 5,168	3%	14%
Gross Margin	$ 918	$ 886	$ 864	4%	3%

Fiscal Year 2009 versus 2008

Excluding the unfavorable impact of foreign currency translation of $442 million primarily in Brazil, utilities revenue increased $627 million, or 11% from the previous year primarily due to an increase in tariff rates of $560 million reflecting the recovery of energy purchases of $453 million that were passed through to customers at our utilities in Brazil and El Salvador and higher volume in Brazil of $62 million.

Excluding the unfavorable impact of foreign currency translation of $62 million in Brazil, utilities gross margin increased $94 million, or 11%, from the previous year primarily due to higher tariffs in El Salvador and Brazil of $107 million, a $64 million recovery of a municipality receivable previously written off, a non-recurring PIS/COFINS fine in 2008 of $33 million and higher volume in the region of $32 million. These increases were partially offset by the unfavorable impact of higher fixed costs of $120 million mainly related to pension expense, labor contingencies and maintenance costs in Brazil.

Fiscal Year 2008 versus 2007

Excluding the favorable impact of foreign currency translation of $357 million primarily in Brazil, utilities revenue increased $382 million, or 7%, from the previous year primarily due to increased rates primarily associated with higher pass-through purchased energy and transmission costs at Eletropaulo of approximately $148 million and higher volume at Eletropaulo and Sul in Brazil of approximately $162 million and $30 million, respectively.

Excluding the favorable impact of foreign currency translation of $67 million primarily in Brazil, utilities gross margin decreased $45 million, or 5%, from the previous year primarily due to a decrease in the non-pass through rates at Eletropaulo as a result of the July 2007 tariff reset of approximately $74 million, increased fixed costs of approximately $71 million at Eletropaulo primarily due to higher provisions for bad debts and higher purchased energy costs at Eletropaulo of approximately $68 million. These decreases were partially offset by higher volume at Eletropaulo of approximately $162 million.

North America Generation

The following table summarizes revenue and gross margin for our Generation segment in North America for the periods indicated:

	For the Years Ended December 31,				
	2009	2008	2007	% Change 2009 vs. 2008	% Change 2008 vs. 2007
	($ s in millions)				
North America Generation					
Revenue	$ 1,940	$ 2,234	$ 2,169	-13%	3%
Gross Margin	$ 477	$ 660	$ 702	-28%	-6%

Table of Contents

Fiscal Year 2009 versus 2008

Excluding the unfavorable impact of foreign currency translation in Mexico of $44 million, generation revenue decreased $250 million, or 11%, from the previous year primarily due to a net decrease of $107 million in New York due to a reduction in the volume of electricity sold in the spot market as a result of lower spot rates partially offset by a rate increase on electricity sold under favorable contracts. Additionally, revenue decreased $80 million due to a reduction in natural gas prices at Merida in Mexico, an increase in outages at Warrior Run in Maryland, TEG/TEP in Mexico and New York of $22 million, $21 million and $17 million, respectively, lower rates at Deepwater in Texas of $20 million and the unfavorable impact of commodity derivatives in New York of $11 million and the unfavorable impact in 2009 of derivative amortization at Warrior Run of $9 million. These decreases were partially offset by a $15 million revenue adjustment at Merida in 2008.

Excluding the unfavorable impact of foreign currency translation of $9 million, generation gross margin decreased $174 million, or 26%, from the previous year primarily due to a net decrease of $72 million in New York driven by a reduction in the volume of electricity sold in the spot market as a result of lower spot rates partially offset by a rate increase on electricity sold under favorable contracts. Additionally, there was a $29 million unfavorable impact of mark-to-market derivative adjustments on coal supply contracts in Hawaii as a result of a gain of $22 million in 2008 compared to a loss of $7 million in 2009, the unfavorable impact in 2009 of derivative amortization at Warrior Run of $9 million and an increase in outages at Warrior Run and in New York of $22 million and $6 million, respectively. Further, gross margin decreased due to the unfavorable impact of commodity derivatives of $11 million and higher emission allowance purchases of $13 million in New York. These decreases were partially offset by a $15 million revenue adjustment at Merida in 2008.

Generation revenue decreased 13%, while generation gross margin decreased 28%, primarily due to the increase in coal prices in New York and the unfavorable impact of derivatives in 2009 in Hawaii that had no corresponding impact on revenue.

Fiscal Year 2008 versus 2007

Generation revenue increased $65 million, or 3%, from the previous year primarily due to higher volume of $38 million at TEG/TEP in Mexico, and net higher revenue at Merida in Mexico of $29 million primarily due to the pass-through of higher fuel costs offset by a revenue adjustment. In addition, revenue increased $8 million at Red Oak in New Jersey, due to higher pricing and availability bonuses. At Warrior Run in Maryland, revenue increased $12 million due to the pass-through of higher fuel costs and higher volume due to no significant outages in 2008. These effects were partially offset by lower volume in New York of $23 million primarily due to planned outages and lower capacity factors.

Generation gross margin decreased $42 million, or 6%, due to lower gross margin in New York of $46 million mainly due to a planned outage and lower volume, and higher fuel prices and outages of $16 million at Deepwater in Texas. Gross margin decreased $13 million at TEG/TEP due primarily to outages and lower rates due to changes in the sales contract rates associated with the refinancing in 2007. These decreases were partially offset by a net increase in gross margin in Hawaii of $29 million primarily due to a $22 million net mark-to-market derivative gain on a coal supply contract and a one time use tax refund of $6 million.

North America Utilities

The following table summarizes revenue and gross margin for our Utilities segment in North America for the periods indicated:

	For the Years Ended December 31,				
	2009	2008	2007	% Change 2009 vs. 2008	% Change 2008 vs. 2007
	($ s in millions)				
North America Utilities					
Revenue	$ 1,068	$ 1,079	$ 1,052	-1%	3%
Gross Margin	$ 239	$ 261	$ 314	-8%	-17%

Table of Contents

Fiscal Year 2009 versus 2008

Utilities revenue decreased $11 million, or 1%, from the previous year primarily due to lower retail volume of $31 million due primarily to milder weather and the economic recession, and a $7 million decrease in wholesale revenue driven by lower market prices. These decreases were partially offset by $32 million of voluntary credits IPL provided to retail customers in 2008. See Item 1. Business *Regulatory Matters North America* of this Form 10-K for further information regarding these credits.

Utilities gross margin decreased $22 million, or 8%, from the previous year primarily due to a decrease in wholesale margin of $16 million due to unfavorable prices and increased pension expense of $25 million largely due to the decline in market value of IPL s pension assets during 2008. These decreases were partially offset by an increase in retail margin of $15 million and a $5 million decrease in property tax expenses. The increase in retail margin was primarily due to the $32 million of voluntary customer credits IPL issued to its to retail customers in 2008 partially offset by lower retail sales volumes in 2009.

The primary drivers for the percentage decline in utilities gross margin being greater than the percentage decline in revenue for the comparable periods are (i) the $25 million increase in pension expense and (ii) the $32 million of voluntary customer credits IPL issued to its retail customers in 2008.

Fiscal Year 2008 versus 2007

Utilities revenue increased $27 million, or 3%, from the previous year primarily due to a $42 million increase in rate adjustments at IPL, related to environmental investments, $42 million of higher fuel and purchased power costs and an $8 million increase in wholesale prices. These increases were offset by $32 million of voluntary customer credits IPL issued to its retail customers in 2008, $16 million of lower retail volume primarily due to unfavorable weather compared to 2007 and an $18 million decrease in wholesale volume.

Utilities gross margin decreased $53 million, or 17%, from the previous year primarily due to lower variable retail margin of $42 million driven by the voluntary customer credits IPL issued to its retail customers in 2008 and lower retail volume. In addition, IPL had higher maintenance expenses of $9 million primarily due to storm restoration costs and the timing and duration of major generating unit overhauls, an increase of $6 million in labor and benefits costs and an increase of $3 million in contractor and consulting costs. These decreases to gross margin were offset by a return recovered through rates on approved environmental investments of $14 million.

Europe Generation

The following table summarizes revenue and gross margin for our Generation segment in Europe for the periods indicated:

	For the Years Ended December 31,				
				% Change	% Change
	2009	2008	2007	2009 vs. 2008	2008 vs. 2007
	($ s in millions)				
Europe Generation					
Revenue	$ 720	$ 1,096	$ 909	-34%	21%
Gross Margin	$ 189	$ 260	$ 240	-27%	8%

Fiscal Year 2009 versus 2008

Excluding the unfavorable impact of foreign currency translation of $146 million across the region, driven mainly by our businesses in Hungary, Kilroot in the United Kingdom and our businesses in Kazakhstan, generation revenue decreased $230 million, or 21%, from the previous year primarily due to lower revenue of

Table of Contents

$101 million as a result of the sale of Ekibastuz and Maikuben in May 2008, lower volume at our businesses in Hungary of $81 million due to the combined impact of the cancellation of one of our PPAs and reduced demand and $67 million at Kilroot, a coal-fired plant, mainly driven by lower dispatch due to favorable gas prices compared to coal. These decreases were partially offset by higher rates of $15 million at our businesses in Kazakhstan.

Excluding the unfavorable impact of foreign currency translation of $35 million, driven mainly by Kilroot and our businesses in Kazakhstan, generation gross margin decreased $36 million, or 14%, from the previous year primarily due to lower gross margin of $41 million as a result of the sale of Ekibastuz and Maikuben in May 2008, lower demand in Hungary of $12 million and an overall increase in fixed costs across the region of $16 million, partially offset by higher capacity revenue at Kilroot and higher energy prices at our businesses in Kazakhstan.

Fiscal Year 2008 versus 2007

Generation revenue increased $187 million, or 21% from the previous year primarily due to an increase in capacity income and energy payments at Kilroot of approximately $105 million, rate recovery and higher volume of approximately $93 million at our businesses in Hungary. In addition, revenue at Kilroot increased approximately $21 million compared to the previous year primarily due to the unfavorable impact of two major overhauls in 2007. These increases were partially offset by a reduction in revenue of approximately $49 million in Kazakhstan following the sale of Ekibastuz and Maikuben in the second quarter of 2008 that was partially offset by approximately $12 million in management fees earned from continuing management agreements for those businesses.

Generation gross margin increased $20 million, or 8% from the previous year primarily due to higher rates and volume of $43 million at Tisza II in Hungary and an increase in capacity income and fewer forced outages at Kilroot of approximately $32 million. These were offset by an increase in fixed costs of $24 million at Kilroot and Tisza II and a reduction in gross margin of $29 million in Kazakhstan following the sale of Ekibastuz and Maikuben in the second quarter of 2008 that was partially offset by $9 million in net gross margin from continuing management agreements for those businesses.

Asia Generation

The following table summarizes revenue and gross margin for our Generation segment in Asia for the periods indicated:

	For the Years Ended December 31,				
	2009	2008	2007	% Change 2009 vs. 2008	% Change 2008 vs. 2007
	($ s in millions)				
Asia Generation					
Revenue	$ 643	$ 553	$ 315	16%	76%
Gross Margin	$ 179	$ 67	$ 82	167%	-18%

Fiscal Year 2009 versus 2008

Excluding the unfavorable impact of foreign currency translation of $23 million, primarily in the Philippines and Sri Lanka, generation revenue increased $113 million, or 20% from the previous year primarily due to the benefit of our new businesses, Masinloc in the Philippines, of $46 million which was acquired in April 2008, and Amman East in Jordan, of $50 million, which commenced single cycle operations in July 2008. Revenue also increased $70 million in 2009 at Masinloc due to improved rates and volume as a result of improved availability and new customer contracts, and $18 million from a one-time favorable energy sales settlement. These increases were partially offset by the decrease in revenue of $71 million at Kelanitissa in Sri Lanka primarily due to a decline in fuel costs which are largely passed through to the customer and higher outages in 2009 as compared to 2008.

Excluding the unfavorable impact of foreign currency translation of $6 million, primarily in the Philippines, generation gross margin increased $118 million, or 176% from the previous year primarily due to the impact of our new businesses at Masinloc of $23 million and Amman East of $17 million. The remaining net increase was primarily a result of a $91 million increase at Masinloc due to higher contract sales, where margins are more favorable than spot sales, lower fuel prices, improved availability and the favorable energy sales settlement described above; and higher capacity charges at Kelanitissa of $10 million. These increases were partially offset by higher fixed costs of $20 million at Masinloc.

Generation revenue increased 16% while gross margin increased 167% primarily due to higher contract margins at Masinloc as a result of improved operations, availability and lower fuel prices, as well as the larger relative impact on gross margin from the one-time favorable energy sales settlement described above.

Fiscal Year 2008 versus 2007

Excluding the favorable impact of foreign currency translation of $4 million, generation revenue increased $234 million, or 74% from the previous year primarily due to revenue generated from our new businesses at Masinloc and Amman East of $149 million and $46 million, respectively, and an increase in rates due to pass-through fuel prices at Kelanitissa of $55 million.

Generation gross margin for the twelve months ended December 31, 2008 decreased $15 million, or 18% from the previous year primarily due to a $15 million unfavorable impact on revenue due to an amended PPA accounted for as a lease at Ras Laffan in Qatar. In addition, following the acquisition in April 2008, Masinloc generated a net gross margin loss of $18 million for the year ended December 31, 2008. These unfavorable effects were partially offset by the favorable impact of $14 million from the start up of commercial operations in July 2008 at Amman East.

Corporate and Other

Corporate and other includes the net operating results from our generation and utilities businesses in Africa, utilities businesses in Europe, AES Wind Generation and other climate solutions and renewables projects which are immaterial for the purposes of separate segment disclosure. The following table excludes the elimination of inter-segment activity and summarizes revenue and gross margin for Corporate and Other entities for the periods indicated:

	For the Years Ended December 31,				
	2009	2008	2007	% Change 2009 vs. 2008	% Change 2008 vs. 2007
	($ s in millions)				
Revenue					
Europe Utilities	$ 286	$ 403	$ 330	-29%	22%
Africa Utilities	$ 370	$ 379	$ 330	-2%	15%
Africa Generation	$ 65	$ 65	$ 65	0%	0%
Wind	$ 133	$ 128	$ 63	4%	103%
Corp/Other	$ 16	$ 37	$ 1	-57%	3600%
Total Corporate and Other	$ 870	$ 1,012	$ 789	-14%	28%
Gross Margin					
Europe Utilities	$ 16	$ 34	$ 21	-53%	62%
Africa Utilities	$ 71	$ 30	$ 46	137%	-35%
Africa Generation	$ 41	$ 28	$ 34	46%	-18%
Wind	$ 11	$ 19	$ 8	-42%	138%
Corp/Other	$ (22)	$ (49)	$ (12)	-55%	-308%
Total Corporate and Other	$ 117	$ 62	$ 97	89%	-36%

Table of Contents

Fiscal Year 2009 versus 2008

Excluding the unfavorable impact of foreign currency translation of $162 million, primarily in the Ukraine, Corporate and Other revenue increased $20 million, or 2%, to $870 million in 2009 from $1.0 billion in 2008. The increase was primarily due to higher tariffs in the Ukraine of $27 million.

Excluding the unfavorable impact of foreign currency translation of $12 million, primarily in the Ukraine, Corporate and Other gross margin increased $67 million, or 108%, to $117 million in 2009 from $62 million in 2008. The increase was primarily due to a decrease in fixed costs partially offset by higher fuel consumption driven by lower hydrology at Sonel, our integrated utility in Cameroon.

Fiscal Year 2008 versus 2007

Excluding the favorable impact of foreign currency translation of $9 million, driven by the favorable impact in Cameroon partially offset by the unfavorable impact in the Ukraine, Corporate and Other revenue increased $214 million, or 27%, to $1.0 billion in 2008 from $789 million in 2007. The increase was primarily due to increased tariffs and volume in the Ukraine of $82 million; an increase of $65 million at our wind generation businesses, primarily due to the expansion of our Buffalo Gap wind facilities in Texas, and an increase in rate and volume of $30 million at Sonel.

Corporate and Other gross margin decreased $35 million, or 36%, to $62 million in 2008 from $97 million in 2007. The decrease was primarily due to increased fixed costs of $55 million at our Utilities businesses in the Ukraine and Cameroon. These were partially offset by the expansion of the Buffalo Gap wind facilities and higher volume and tariffs of $59 million in the Ukraine and Cameroon.

General and Administrative Expense

General and administrative expense includes those expenses related to corporate staff functions and/or initiatives, executive management, finance, legal, human resources, information systems, and certain development costs which are not allocable to our business segments.

General and administrative expenses decreased $26 million, or 7%, to $345 million for the year ended December 31, 2009 from $371 million for the year ended December 31, 2008. The decrease is primarily related to 2008 professional fees associated with remediation efforts and a reduction in business development costs. The favorable variance is partially offset by an increase in current year costs associated with the worldwide implementation of SAP.

General and administrative expenses decreased $7 million, or 2%, to $371 million for the year ended December 31, 2008 from $378 million for the year ended December 31, 2007. The decrease is primarily due to a reduction in professional fees related to material weakness remediation efforts, partially offset by higher spending on SAP implementation projects and the expansion of our renewables initiatives.

Interest expense

Interest expense decreased $288 million, or 16%, to $1.5 billion in 2009 primarily due to lower interest rates globally due to economic conditions and as a result of inflationary adjustments to the market price index in Brazil. In addition, the expense decreased as a result of favorable foreign currency translation, mainly in Brazil, lower interest expenses associated with decreased debt balances at Eletropaulo and lower refinancing costs at IPALCO. These decreases were partially offset by higher interest expenses at our Masinloc plant in the Philippines which was acquired in April 2008, and interest expense at Infovias in Brazil where a fee on a non-exercised credit line was written off.

Table of Contents

Interest expense increased $48 million, or 3%, to $1.8 billion in 2008 primarily due to additional interest expense at Masinloc following its acquisition in April 2008, interest expense associated with derivatives at Eletropaulo, Panama and Puerto Rico, as well as unfavorable foreign currency translation in Brazil. These increases were offset by decreases from the elimination of a financial transaction tax in Brazil, a decrease in regulatory liabilities at Eletropaulo, and a decrease in capitalized interest on development projects at Kilroot.

Interest income

Interest income decreased $171 million, or 33%, to $348 million in 2009 primarily due to lower interest rates and lower investment balances in Brazil, unfavorable foreign currency translation on the Brazilian Real, and the impact of decreased interest rates and inflationary adjustments on accounts receivable in 2008 at Gener in Chile, and decreased cash balance at the parent company.

Interest income increased $30 million, or 6%, to $519 million in 2008 primarily due to interest income on short-term investments and cash equivalents at two of our subsidiaries in Brazil, inflationary adjustments on accounts receivable at Gener, and interest earned on a convertible loan acquired in March 2008. These increases were offset by decreases due to lower interest income related to a gross receipts tax recovery at Tietê recorded during the second quarter of 2007 and decreased interest income related to derivatives at TEG/TEP.

Other income

	Years Ended December 31,		
	2009	**2008**	**2007**
		(in millions)	
Extinguishment of tax liabilities	$ 165	$	$
Tax credit settlement	129		
Management performance incentive	80		
Gain on extinguishment of liabilities	3	199	22
Insurance proceeds		40	18
Gain on sale of assets	14	34	24
Contract settlement gain			135
Gross receipts tax recovery			93
Other	75	104	66
Total other income	$ 466	$ 377	$ 358

Other income of $466 million for the year ended December 31, 2009 included $165 million from the reduction in interest and penalties associated with federal tax debts at Eletropaulo and Sul as a result of the Refis program and a $129 million gain related to a favorable court decision enabling Eletropaulo to receive reimbursement of excess non-income taxes paid from 1989 to 1992 in the form of tax credits to be applied against future tax liabilities. The net impact to the Company after income taxes and noncontrolling interests for these items was $44 million. In addition, the Company recognized income in 2009 of $80 million from a performance incentive bonus for management services provided to Ekibastuz and Maikuben in 2008. The management agreement was related to the sale of these businesses in Kazakhstan in May 2008; see further discussion of this transaction in Note 14 *Acquisitions and Dispositions.*

Other income of $377 million for the year ended December 31, 2008 included gains on the extinguishment of a gross receipts tax liability and a legal contingency at Eletropaulo of $117 million and $75 million, respectively, $32 million of cash proceeds related to a favorable legal settlement at Southland in California, $29 million of insurance recoveries for damaged turbines at Uruguaiana, $23 million of gains associated with a sale of land at Eletropaulo and sales of turbines at Itabo, and compensation of $18 million for the impairment associated with the settlement agreement to shut down Hefei.

Table of Contents

Other income of $358 million for the year ended December 31, 2007 included a $135 million contract settlement gain at Eastern Energy in New York, a $93 million gross receipts tax recovery at Eletropaulo and Tiete, and favorable legal settlements at Eletropaulo and Red Oak in New Jersey.

Other expense

	Years Ended December 31,		
	2009	2008	2007
		(in millions)	
Loss on extinguishment of liabilities	$	$ 70	$ 106
Loss on sale and disposal of assets	42	34	79
Other	69	57	68
Total other expense	$ 111	$ 161	$ 253

Other expense of $111 million for the year ended December 31, 2009 included a $13 million loss recognized when three of our businesses in the Dominican Republic received $110 million par value bonds issued by the Dominican Republic government to settle existing accounts receivable for the same amount from the government-owned distribution companies. The loss represented an adjustment to reflect the fair value of the bonds on the date received. Other expense also included losses on the disposal of assets at Eletropaulo and Andres and contingencies at our businesses in Kazakhstan and Alicura.

Other expense of $161 million for the year ended December 31, 2008 included $69 million of losses on the retirement of debt at the Parent Company in connection with the refinancing in June 2008, as further discussed in Note 10 Long Term Debt, and IPALCO associated with a $375 million refinancing in April 2008, and losses on disposal of assets primarily at Eletropaulo in Brazil.

Other expense of $253 million for the year ended December 31, 2007 included a loss of $90 million on the retirement of Senior Secured Notes at the parent company, a $28 million charge related to an increase in contingencies in Kazakhstan and losses on the sale and disposal of assets at Eletropaulo and Sul in Brazil.

Goodwill Impairment

In 2009, the Company recognized goodwill impairment expense of $122 million. This was a result of impairment at certain of our businesses in the United Kingdom and Ukraine as a result of the Company s annual goodwill impairment evaluation as of October 1. The most significant goodwill impairment was at Kilroot, our generation business in the United Kingdom. Factors contributing to the recognition of impairment included: reduced profit expectations based on latest estimates of future commodity prices and reduced expectations on the recovery of cash flows on the existing plant following the Company s decision to forgo capital expenditures to meet emission allowance requirements taking effect in 2024. The fair value of the Company s reporting units are inherently sensitive to the assumptions underlying the estimates of fair value. Note 1 *General and Summary of Significant Accounting Policies, Goodwill and Intangibles*, provides a more detailed discussion of those assumptions. As discussed in Key Trends and Uncertainties, in the future, the fair values of the Company s reporting units might decline as a result of adverse changes in their operating environments or the businesses reaching the end of their finite lives, which could require the Company to record additional goodwill impairment charges.

The Company did not incur any goodwill impairment charge in 2008 and 2007.

Asset Impairment Expense

As discussed in Note 19 Asset Impairment Expense to the Consolidated Financial Statements included in Item 8 of this Form 10-K, asset impairment expense for the year 2009 was $25 million and consisted primarily of the following:

In 2009, the Company recognized a pre-tax long-lived asset impairment charge of $11 million related to the Company s Piabanha hydro project in Brazil. The Company determined that the carrying value exceeded the future discounted cash flows and abandoned the project.

Asset impairment expense for the year 2008 was $175 million. In the fourth quarter of 2008, and in response to the financial market crisis, the Company reviewed and prioritized projects in the development pipeline. From this review, the Company determined that the carrying value exceeded the future discounted cash flows for certain projects. As a result, the Company recorded an impairment charge of $75 million ($34 million, net of noncontrolling interests and income taxes) related to two liquefied natural gas projects in North America and a non-power development project at one of our facilities in North America. During 2008, the Company recognized additional impairment charges of $36 million related to long-lived assets at Uruguaiana. The impairment was triggered by a combination of gas curtailments and increases in the spot market price of energy in 2007 that continued in 2008. Following an initial impairment charge in the fourth quarter of 2007, further charges were incurred in 2008 due to fixed asset purchase agreements in place. During the first half of 2008, the Company withdrew from projects in South Africa and Israel which resulted in impairment charges of $36 million. The Company also recognized an impairment of $18 million related to the shutdown of the Hefei plant in China.

Asset impairment expense for the year 2007 was $408 million and consisted primarily of a pre-tax impairment charge of approximately $352 million at Uruguaiana, a gas-fired thermoelectric plant located in Brazil. The impairment was the result of an analysis of Uruguaiana s long-lived assets, which was triggered by the combination of gas curtailments and increases in the spot market price of energy. In addition, asset impairments included $25 million from a compressor failure at Placerita, a subsidiary in California and $14 million related to a prepayment advanced to AgCert for a specified amount of future CER credits.

Gain on sale of investments

Gain on sale of investments of $131 million in 2009 consisted primarily of $98 million recognized in May 2009 related to the termination of the management agreement between the Company and Kazakhmys PLC for Ekibastuz and Maikuben, a gain of $14 million from the sale of the remaining assets associated with the shutdown of the Hefei plant in China and $13 million from the reversal of a contingent liability related to the Kazakhstan sale in 2008.

Gain on sale of investments of $909 million in 2008 consisted primarily of the sale in May 2008 of two wholly-owned subsidiaries in Kazakhstan, Ekibastuz and Maikuben for a net gain of $905 million.

(Loss) gain on sale of subsidiary stock

Loss on sale of subsidiary stock of $31 million in 2008 was the result of sales of AES Gener shares made by our wholly-owned subsidiary Cachagua. In November 2008, Cachagua sold 9.6% of its ownership in Gener to a third party reducing its ownership in Gener to 70.6%.

Gain on sale of subsidiary stock in 2007 of $134 million was a result of net gains recognized on sales approximating an 11% ownership interest in Gener reducing our ownership interest in Gener to 80.2%.

In accordance with the new accounting guidance for noncontrolling interests, future transactions of this type will be accounted for as equity transactions and will not result in a gain or loss on the sale.

Table of Contents

Foreign currency transaction gains (losses) on net monetary position

The following table summarizes the gains (losses) on the Company s net monetary position from foreign currency transaction activities:

	Years Ended December 31,		
	2009	2008	2007
		(in millions)	
AES Corporation	$ 13	$ 38	$ 31
Chile	65	(102)	(4)
Philippines	15	(57)	
Brazil	(9)	(44)	5
Argentina	(10)	(22)	(8)
Kazakhstan	(24)	11	10
Colombia	(11)	5	(7)
Other	(6)	(13)	2
Total[(1)]	$ 33	$ (184)	$ 29

(1) Includes $(39) million, $10 million and ($22) million of gains (losses) on foreign currency derivative contracts for the years ended December 31, 2009, 2008 and 2007, respectively.

The Company recognized foreign currency transaction gains of $33 million for the year ended December 31, 2009. These consisted primarily of gains in Chile, at The AES Corporation and in the Philippines partially offset by losses in Kazakhstan, Colombia, Argentina and Brazil.

Gains of $65 million in Chile were primarily due to the appreciation of the Chilean Peso by 20% resulting in gains at Gener (a U.S. Dollar functional currency subsidiary) associated with its net working capital denominated in Chilean Peso, mainly cash and accounts receivables. This gain was partially offset by $14 million in losses on foreign currency derivatives.

Gains of $13 million at The AES Corporation were primarily due to the settlement of the senior unsecured credit facility and the revaluation of notes receivable denominated in the Euro, partially offset by losses on debt denominated in British Pounds.

Gains of $15 million in the Philippines were primarily due to the appreciation of the Philippine Peso of 3%, resulting in gains at Masinloc, a Philippine Peso functional currency subsidiary, on the remeasurement of U.S. Dollar denominated debt.

Losses of $24 million in Kazakhstan were primarily due to net foreign currency transaction losses of $12 million related to energy sales denominated and fixed in the U.S. Dollar and $12 million of foreign currency transaction losses on debt and other liabilities denominated in currencies other than the Kazakh Tenge.

Losses of $11 million in Colombia were primarily due to appreciation of the Colombian Peso by 9%, resulting in losses at Chivor (a U.S. Dollar functional currency subsidiary) associated with its Colombian Peso denominated debt and losses on foreign currency derivatives.

Losses of $10 million in Argentina were primarily due to the devaluation of the Argentine Peso by 10% in 2009, resulting in losses at Alicura (an Argentine Peso functional currency subsidiary) associated with its U.S. Dollar denominated debt, partially offset by derivative gains.

Losses of $9 million in Brazil were primarily due to energy purchases made by Eletropaulo denominated in U.S. Dollar, resulting in foreign currency transaction losses of $18 million, partially offset by gains of $9 million due to the appreciation in 2009 of the Brazilian Real by 25%, resulting in gains at Sul and Uruguaiana associated with U.S. Dollar denominated liabilities.

Table of Contents

The Company recognized foreign currency transaction losses of $184 million for the year ended December 31, 2008. These consisted primarily of losses in Chile, the Philippines, Brazil and Argentina partially offset by gains at The AES Corporation and in Kazakhstan.

Losses of $102 million in Chile were primarily due to the devaluation of the Chilean Peso by 28% in 2008, resulting in losses at Gener, a U.S. Dollar functional currency subsidiary, associated with its net working capital denominated in Chilean Pesos, mainly cash, accounts receivable and VAT receivables.

Losses of $57 million in the Philippines were primarily due to remeasurement losses at Masinloc, a Philippine Peso functional currency subsidiary, on U.S. Dollar denominated debt resulting from depreciation of the Philippine Peso of 14% in 2008.

Losses of $44 million in Brazil were primarily due to the realization of deferred exchange variance on past energy purchases made by Eletropaulo denominated in U.S. Dollar.

Losses of $22 million in Argentina were primarily due to the devaluation of the Argentine Peso by 10% in 2008, resulting in losses at Alicura, an Argentine Peso functional currency subsidiary, associated with its U.S. Dollar denominated debt.

Gains of $38 million at The AES Corporation were primarily due to debt denominated in British Pounds and gains on foreign exchange derivatives, partially offset by losses on notes receivable denominated in the Euro.

Gains of $11 million in Kazakhstan were primarily due to net foreign currency transaction gains of $16 million related to energy sales denominated and fixed in the U.S. Dollar, offset by $5 million of foreign currency transaction losses on external and intercompany debt denominated in other than the Kazakh Tenge functional currency.

Foreign currency transaction gains of $29 million for the year ended December 31, 2007 primarily consisted of gains at The AES Corporation and in Kazakhstan, partially offset by losses in Argentina and Colombia.

Gains of $31 million at The AES Corporation were primarily the result of favorable exchange rates for debt denominated in British Pounds and the Euro.

Gains of $10 million in Kazakhstan were primarily due to $12 million of gains related to debt denominated in currencies other than the Kazakh Tenge functional currency, partially offset by $3 million of losses related to energy sales denominated and fixed in the U.S. Dollar.

Losses of $8 million in Argentina were primarily due to the devaluation of the Argentine Peso by 3% in 2007, resulting in losses of $11 million at Alicura associated with its U.S. Dollar denominated debt.

Losses of $7 million in Colombia were primarily due to the appreciation of the Colombian Peso by 11% in 2007 at Chivor, a U.S. Dollar function currency subsidiary.

Other non-operating expense

Other non-operating expense was $12 million in 2009, consisting primarily of an other-than-temporary impairment of a cost method investment. During the first quarter of 2009, the market value of the investee s shares continued to decline due to the downward trends in the capital markets and management concluded that the $10 million decline was other-than-temporary.

Other non-operating expense was $15 million in 2008 and related primarily to an impairment of the Company s investment in a company developing a blue gas (coal to gas) technology project. The Company made this investment in September 2007 and accounted for the investment in convertible preferred shares under the cost method of accounting. During the fourth quarter of 2008, the market value of the shares materially declined due to downward trends in the capital markets and management concluded that the decline was other-than-temporary and recorded an impairment charge of $10 million. Additionally, the Company recorded an other-than-temporary impairment charge of approximately $5 million related to its investments in other entities developing new energy technology and products.

Other non-operating expense was $57 million in 2007 and reflected the impairment in the Company s investment in AgCert, a U.K. based corporation, publicly traded on the London Stock Exchange, that produces CER credits. The Company acquired its investment in AgCert in May 2006 and, similar to the circumstances stated above, the market value of the Company s investment materially declined during the first half of 2007 and the Company recorded an other-than-temporary impairment charge of $52 million in 2007. An additional charge of $5 million was recognized for the decrease in value of the AgCert warrants also held by the Company. The Company began consolidating AgCert in January 2008 when it became the primary beneficiary.

Income taxes

Income tax expense on continuing operations decreased $172 million, or 22%, to $599 million in 2009. The Company s effective tax rates were 26% for 2009 and 29% for 2008. The decrease in the 2009 effective tax rate was primarily due to tax benefit recorded in 2009 upon the release of valuation allowance at certain U.S. and Brazilian subsidiaries, $165 million of non-taxable income recorded at 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.

Income tax expense on continuing operations increased $95 million, or 14%, to $771 million in 2008. The Company s effective tax rates were 29% for 2008 and 46% for 2007. The decrease in the 2008 effective tax rate was primarily due to the gain of $905 million recorded on the sale of the Kazakhstan businesses in the second quarter of 2008, offset by U.S. taxes on distributions from the Company s primary holding company to facilitate early retirement of parent debt in 2008. The decrease was also attributable to the implementation of a tax planning strategy that mitigated the impact of the Mexico Flat Rate Business Tax (IETU) enacted in the fourth quarter of 2007. The strategy resulted in a reduction to deferred tax expense in 2008 of $24 million and $23 million at TEG and TEP, respectively.

Net equity in earnings of affiliates

Net equity in earnings of affiliates increased $59 million, or 179%, to $92 million in 2009 primarily due to a cash settlement received by Cartagena, in Spain, in June 2009 for liquidated damages received related to a construction delay from December 2005 to November 2006; increased earnings at Guacolda in Chile mainly due to lower cost of coal; increased earnings of Chigen affiliates from higher tariffs partially offset by lower volume and a valuation write-off in 2008 at an affiliate in Turkey. These increases were partially offset by decreased earnings at OPGC, in India, mainly due to lower tariff and a dividend distribution tax in March 2009 and increased expenses for an equipment overhaul at Elsta in the Netherlands.

Net equity in earnings of affiliates decreased $43 million, or 57%, to $33 million in 2008 primarily due to the impact of increased coal prices at Yangcheng, a coal-fired plant in China, a decrease as a result of development costs related to AES Solar, formed in March 2008, and an additional write-off of three projects in Turkey that were abandoned in December 2007. Additionally, earnings decreased due to the sale of an equity investment in a wind project in the fourth quarter of 2007, a decrease in earnings at OPGC, in India, and decreased earnings due to a discontinuance of hedge accounting for a number of interest rate swaps at Guacolda in Chile. These losses were partially offset by a decrease in net losses at Cartagena in Spain primarily from a write-off of deferred financing costs in 2007 that did not recur in 2008.

Table of Contents

Income from continuing operations attributable to noncontrolling interests

Income from continuing operations attributable to noncontrolling interests increased $337 million, or 44%, to $1.1 billion in 2009 primarily due to increases in gross margin and other income, lower interest expense and a decrease in impairments in 2009 at our Brazilian businesses, and increases in gross margin and foreign currency transaction gains at our businesses in Chile. In addition, in the fourth quarter of 2009, income from continuing operations attributable to noncontrolling interests increased $44 million at certain of our wind generation businesses as a result of a charge related to the potential future taxes that could be deemed due in the calculation of the hypothetical liquidation value of certain of our wind tax equity partnerships.

Income from continuing operations attributable to noncontrolling interests increased $367 million, or 91%, to $770 million in 2008 primarily due to the decreased losses as a result of the impairment recognized at Uruguaiana during 2007, increased earnings at Eletropaulo, Gener, Itabo, Panama and Tietê, as well as an increase in noncontrolling interests from approximately 20% to approximately 29% as a result of the sale of shares in Gener in November 2008. These increases were partially offset by an impairment recognized in the Bahamas, a net loss at Masinloc, and decreased earnings at Ras Laffan, Sonel, and Caess-EEO & Clesa in El Salvador.

Discontinued operations

As further discussed in Note 21 Discontinued Operations and Held for Sale Businesses to the Consolidated Financial Statements included in Item 8 of this Form 10-K, Discontinued Operations includes the results of seven businesses: Lal Pir and Pak Gen, generation businesses in Pakistan, (held for sale in December 2009); Barka, a generation business in Oman, (held for sale in December 2009); Jiaozuo, a generation business in China, (sold in December 2008); La Electricidad de Caracas (EDC), a utility business in Venezuela, (sold in May 2007); Central Valley, a generation business in California (sold in July 2007); and Eden, a utility business in Argentina (sold in June 2007). Prior periods have been restated to reflect these businesses within Discontinued Operations for all periods presented.

In 2009, income from operations of discontinued businesses, net of tax and income attributable to noncontrolling interests, was $35 million and reflected the operations of our 35% stake in Barka, a combined cycle gas facility and water desalination plant in Oman, and our 55% stake in Pak Gen and Lal Pir, two oil-fired facilities in Pakistan which are under contract for sale in 2010. Loss on disposal of discontinued businesses, net of tax and loss attributable to noncontrolling interests was $105 million and represented the difference between the net book value of the Company s interests in its Pakistan businesses and their estimated fair value.

In 2008, income from operations of discontinued businesses, net of tax and income attributable to noncontrolling interests, was $41 million and reflected the operations of Barka, Pak Gen, Lal Pir and Jiaozuo, a coal-fired generation facility in China sold in December 2008. The Company received $73 million for its 70% interest in the business. The net gain on the disposition was $7 million.

In 2007, income from operations of discontinued businesses, net of tax and income attributable to noncontrolling interests, was $112 million and reflected the operations of Barka, Pak Gen, Lal Pir, Jiaozuo, EDC, Central Valley and Eden. EDC, Eden, and Central Valley were sold in May, June and July 2007, respectively, therefore their results are reflected in the Company s results of operations through their respective sales dates. Loss on the disposal of discontinued businesses net of tax and loss attributable to noncontrolling interests was $661 million and primarily related to the loss on the sale of EDC.

Critical Accounting Estimates

The Consolidated Financial Statements of AES are prepared in conformity with GAAP, which requires the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the periods presented.

AES s significant accounting policies are described in Note 1 General and Summary of Significant Accounting Policies to the Consolidated Financial Statements included in Item 8 of this Form 10-K.

An accounting estimate is considered critical if:

- the estimate requires management to make assumptions about matters that were highly uncertain at the time the estimate was made;
- different estimates reasonably could have been used; or
- the impact of the estimates and assumptions on financial condition or operating performance is material.

Management believes that the accounting estimates employed are appropriate and the resulting balances are reasonable; however, actual results could materially differ from the original estimates, requiring adjustments to these balances in future periods. Management has discussed these critical accounting policies with the Audit Committee, as appropriate. Listed below are the Company s most significant critical accounting estimates and assumptions used in the preparation of the Consolidated Financial Statements.

Income Tax Reserves

We are subject to income taxes in both the United States and numerous foreign jurisdictions. Our worldwide income tax provision requires significant judgment and is based on calculations and assumptions that are subject to examination by the Internal Revenue Service and other taxing authorities. The Company and certain of its subsidiaries are under examination by relevant taxing authorities for various tax years. The Company regularly assesses the potential outcome of these examinations in each of the taxing jurisdictions when determining the adequacy of the provision for income taxes. Accounting guidance for uncertainty in income taxes prescribes a more-likely-than-not recognition threshold. Tax reserves have been established, which the Company believes to be adequate in relation to the potential for additional assessments. Once established, reserves are adjusted only when there is more information available or when an event occurs necessitating a change to the reserves. While the Company believes that the amount of the tax estimates are reasonable, it is possible that the ultimate outcome of current or future examinations may exceed current reserves in amounts that could be material.

Goodwill

Effective January 1, 2009, the Company adopted the new accounting guidance on fair value measurement of nonfinancial assets and liabilities measured on a nonrecurring basis. We test goodwill at the reporting unit level for impairment annually on October 1 and whenever events or circumstances indicate it is more likely than not that impairment may have occurred. Such indicators could include a significant adverse change in the business climate or a decision to sell or dispose of all or a portion of a reporting unit. As discussed in detail in Note 1 *General and Summary of Significant Accounting Policies, Goodwill and Other Intangibles* included in Item 8 of this Form 10-K goodwill impairment is evaluated using a two-step process. The first step is to identify if a potential impairment exists by comparing the fair value of a reporting unit with its carrying value. Determining whether potential impairment exists requires us to estimate the fair value of the respective reporting unit. The new accounting guidance recommends three approaches to measure fair value: 1) Cost approach; 2) Market approach; and 3) Income approach. Historically, an internally developed discounted cash flow model based on the income approach was used to estimate the fair value of reporting units. The Company incorporated several changes in its internal valuation model to align its valuation approach with the new accounting guidance. In the revised valuation model, the fair value of a reporting unit is estimated using internal budgets and forecasts, adjusted for any market participants assumptions, discounted at the Weighted Average Cost of Capital (WACC). If the fair value of a reporting unit exceeds its carrying value, goodwill of the reporting unit is not considered to be impaired and no further analysis is required. In determining the fair value, management relies primarily on the results of the income-based approach as most of the valuation assumptions used to derive the discount rate are market observable, directly or indirectly.

Table of Contents

Under the income approach, the fair value is the result of the application of a significant number of assumptions related to the discount rate and cash flow forecasts. Many of discount rate-related assumptions are market observable; however, the assumptions underlying our cash flow forecasts involve considerable judgment by management. These include growth rate, terminal value, asset retirement obligations, and macro economic factors such as industry demand, inflation, exchange rates and commodity prices. The fair value of a reporting unit could be sensitive to one or more assumption and different reporting units could be sensitive to different assumptions. Management uses a market-based approach to corroborate the fair value estimated under the income approach and to determine the reasonableness of the fair value derived using the discounted cash flow analysis. As part of the impairment evaluation process, we analyze the sensitivity of a reporting unit s fair value to underlying assumptions. The level of scrutiny increases as the gap between a reporting unit s fair value and carrying value decreases. Changes in any of these assumptions could result in management reaching a different conclusion regarding the potential impairment of a reporting unit, which could be material. Our impairment analysis inherently involves uncertainties from uncontrollable events that could positively or negatively impact the anticipated future economic and operating conditions.

If the carrying value exceeds the reporting unit s fair value, this could indicate potential impairment and step two of the goodwill evaluation process is required to determine if goodwill is impaired and to measure the amount of impairment loss to recognize, if any. In determining the implied fair value of goodwill for impairment measurement, the fair value measurement accounting guidance requires measuring all assets and liabilities at fair value. This includes determining the fair value of unrecognized assets and liabilities not recognized on the books as would be done in a business combination. When a step two analysis must be completed, the fair value of individual assets and liabilities is determined using valuations (which in some cases may be based in part on the reports of external valuation specialists), or other observable sources of fair value, as appropriate.

In 2009, the Company recognized goodwill impairment of $122 million. This was a result of impairment at certain of our businesses in the United Kingdom and Ukraine. The most significant impairment was at Kilroot, our coal-fired generation business in the United Kingdom. Factors contributing to the recognition of impairment included: reduced profit expectations based on the latest estimates of future commodity prices and reduced expectations regarding the recovery of cash flows on the existing plant following the Company s decision to forgo capital expenditures to meet emission allowance requirements taking effect in 2024.

Regulatory Assets and Liabilities

The Company accounts for certain of its regulated operations in accordance with the regulatory accounting standards. As a result, AES recognizes assets and liabilities that result from the regulated ratemaking process that would not be recognized under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred or included in future rate initiatives. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities and the status of any pending or potential deregulation legislation. If future recovery of costs ceases to be probable, any asset write-offs would be required to be recognized in operating income.

Fair Value

Fair Value of Financial Instruments

A significant number of the Company s financial instruments are carried at fair value with changes in fair value recognized in earnings or other comprehensive income each period. The Company makes estimates regarding the valuation of assets and liabilities measured at fair value in preparing the Consolidated Financial Statements. These assets and liabilities include short and long-term investments in debt and equity securities, included in the balance sheet line items Short-term investments and Other assets (Noncurrent) , derivative assets, included in Other current assets and Other assets (Noncurrent) and derivative liabilities, included in Accrued and other liabilities (current) and Other long-term liabilities . The Company uses valuation techniques and methodologies that maximize the use of observable inputs and minimize the use of unobservable inputs. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices are not available, valuation models are applied to estimate the fair value using the available observable inputs. The valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the price transparency for the instruments or market and the instruments complexity. Investments are generally fair valued based on quoted market prices or other observable market data such as interest rate indices. The Company s investments are primarily certificates of deposit, government debt securities and money market funds. Derivatives are valued using observable data as inputs into internal valuation models. The Company s derivatives primarily consist of interest rate swaps, foreign currency instruments, and commodity and embedded derivatives. Additional discussion regarding the nature of these financial instruments and valuation techniques can be found in Note 6 Fair Value of Financial Instruments.

Accounting for Derivative Instruments and Hedging Activities

We enter into various derivative transactions in order to hedge our exposure to certain market risks. We primarily use derivative instruments to manage our interest rate, commodity and foreign currency exposures. We do not enter into derivative transactions for trading purposes.

In accordance with the accounting standards for derivatives and hedging, we recognize all derivatives as either assets or liabilities in the balance sheet and measure those instruments at fair value except where derivatives qualify and are designated as normal purchase/normal sale transactions. Changes in fair value of derivatives are recognized in earnings unless specific hedge criteria are met. Income and expense related to derivative instruments are recognized in the same category as generated by the underlying asset or liability.

The accounting standards for derivatives and hedging enable companies to designate qualifying derivatives as hedging instruments based on the exposure being hedged. These hedge designations include fair value hedges and cash flow hedges. Changes in the fair value of a derivative that is highly effective and is designated and qualifies as a fair value hedge, are recognized in earnings as offsets to the changes in fair value of the exposure being hedged. The Company has no fair value hedges at this time. Changes in the fair value of a derivative that is highly effective and is designated as and qualifies as a cash flow hedge, are deferred in accumulated other comprehensive income and are recognized into earnings as the hedged transactions occur. Any ineffectiveness is recognized in earnings immediately. For all hedge contracts, the Company provides formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging.

The Company adopted the fair value measurement accounting standard for financial assets and liabilities on January 1, 2008. The standard provides additional guidance on the definition of fair value and defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or exit price. The fair value measurement standard requires the Company to consider and reflect the assumptions of market participants in the fair value calculation. These factors include nonperformance risk (the risk that the obligation will not be fulfilled) and credit risk, both of the reporting entity (for liabilities) and of the counterparty (for assets). These factors were not previously considered in the fair value calculation. Due to the nature of the Company s interest rate swaps, which are typically associated with non-recourse debt, credit risk for AES is evaluated at the subsidiary level rather than at the Parent Company level. Nonperformance risk on the Company s derivative instruments is an adjustment to the initial asset/liability fair value position that is derived from internally developed valuation models that utilize observable market inputs.

Table of Contents

As a result of uncertainty, complexity and judgment, accounting estimates related to derivative accounting could result in material changes to our financial statements under different conditions or utilizing different assumptions. As a part of accounting for these derivatives, we make estimates concerning nonperformance, volatilities, market liquidity, future commodity prices, interest rates, credit ratings (both ours and our counterparty s), and exchange rates.

The fair value of our derivative portfolio is generally determined using internal valuation models, most of which are based on observable market inputs including interest rate curves and forward and spot prices for currencies and commodities. The Company derives most of its financial instrument market assumptions from market efficient data sources (e.g. Bloomberg and Platt s). In some cases, where market data is not readily available, management uses comparable market sources and empirical evidence to derive market assumptions to determine a financial instrument s fair value. In certain instances, the published curve may not extend through the remaining term of the contract and management must make assumptions to extrapolate the curve. Additionally, in the absence of quoted prices, we may rely on indicative pricing quotes from financial institutions to input into our valuation model for certain of our foreign currency swaps. These indicative pricing quotes do not constitute either a bid or ask price and therefore are not considered observable market data. For individual contracts, the use of different valuation models or assumptions could have a material effect on the calculated fair value.

Fair Value of Nonfinancial Assets and Liabilities

The Company adopted the fair value measurement accounting guidance for nonfinancial assets and liabilities effective January 1, 2009. The most significant of these estimates surround the fair value measurement of long-lived tangible and intangible assets when tested for impairment upon a triggering event or during the annual impairment evaluation for indefinite-lived intangible assets, including goodwill. These estimates include making assumptions regarding useful life, the impact of economic obsolescence and expected future cash flows. Additional factors considered for goodwill are discussed above in the Goodwill section.

Fair Value Hierarchy

The Company uses valuation techniques and methodologies that maximize the use of observable inputs and minimize the use of unobservable inputs. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices are not available, valuation models are applied to estimate the fair value using the available observable inputs. The valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the price transparency for the instruments or market and the instruments complexity.

To increase consistency and enhance disclosure of the fair value of financial instruments, the fair value measurement standard creates a fair value hierarchy to prioritize the inputs used to measure fair value into three categories. A financial instrument s level within the fair value hierarchy is based on the lowest level of input significant to the fair value measurement, where Level 1 is the highest and Level 3 is the lowest. For more information regarding the fair value hierarchy, see Note 1 General and Summary of Significant Accounting Policies in Item 8. Financial Statements and Supplementary Data of this Form 10-K.

New Accounting Pronouncements

Effective January 1, 2009, we adopted new accounting provisions related to the following topics as a result of new accounting guidance issued by the Financial Accounting Standards Board (FASB).

Fair Value Measurement of Nonfinancial Assets and liabilities on a Nonrecurring Basis. As explained above, we adopted the fair value accounting guidance for nonfinancial assets and liabilities.

Noncontrolling Interests in Consolidated Financial Statements. This guidance changed our accounting and reporting for minority interests, which are now classified as a component of equity and referred to as noncontrolling interests. This guidance resulted in the reclassification of minority interest previously classified outside of equity into equity with their title renamed to Noncontrolling Interests in the accompanying consolidated balance sheets and statement of changes in equity. Additionally, net income and comprehensive income attributable to noncontrolling interests are reflected separately from consolidated net income and comprehensive income in the accompanying consolidated statements of operations and statements of changes in equity. Financial statements for all periods presented in this form have been reclassified to conform to the new presentation requirements, as required by SEC regulations.

Business Combinations This guidance has significantly changed how business acquisitions are accounted for at their acquisition date and in subsequent periods. The new guidance changes the accounting for the business combination at the acquisition date to a fair value based approach rather than the cost allocation approach previously used. Other differences include changes in the accounting for acquisition related costs, contingencies and income taxes. This new guidance is applicable prospectively for business combinations that occurred after January 1, 2009.

Determination of the Useful Life of Intangible Assets. The new accounting guidance amended the factors we must consider when developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The new guidance requires a consistent approach between the useful life of a recognized intangible asset and the period of expected cash flows used to measure the fair value of an asset as required under the business combination accounting guidance. In addition, enhanced disclosures are required when an intangible asset s expected future cash flows are affected by an entity s intent and/or ability to renew or extend the arrangement. The new guidance was applied prospectively and the adoption did not have a material impact on our financial condition, results of operations or cash flows.

Equity Method Investment Accounting Considerations The new accounting guidance clarified the accounting for certain transactions and impairment considerations involving equity method investments. The adoption of this guidance, which was applied prospectively, did not have a significant impact on our current practice.

Fair Value Measurement and Disclosures for Liabilities The new accounting guidance provided clarification that in circumstances in which a quoted price in an active market for the identical liability is not available, a reporting entity is required to measure fair value using either a valuation technique that uses the quoted price of the identical liability when traded as an asset or quoted prices for similar liabilities or similar liabilities when traded as assets or another valuation technique that is consistent with the fair value principles of the income approach or market approach. It also clarified that when estimating the fair value of a liability, a reporting entity is not required to include a separate input or adjustment to other inputs to reflect the existence of a restriction that prevents the transfer of the liability. The adoption of this guidance did not have a material impact on the Company s financial statements.

Accounting Pronouncements Issued But Not Yet Effective

The following accounting standards have been issued, but as of December 31, 2009, are not yet effective for and have not been adopted by AES.

ASU No. 2009-17, Consolidations, Improvements to Financial Reporting by Enterprises involved with Variable Interest Entities (ASU No. 2009-17) (former FAS No. 167, Amendments to FASB Interpretation No. 46(R))

In June 2009, the FASB issued an amendment to the accounting and disclosure requirements for the consolidation of variable interest entities (VIEs). The amendment requires an entity to qualitatively, rather than quantitatively, assess the determination of the primary beneficiary of a VIE. This determination should be based on whether the entity has the power to direct the activities that most significantly impact the economic performance of the VIE and the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. Other key changes include: the requirement for an ongoing reconsideration of the primary beneficiary, the criteria for determining whether service provider or decision maker contracts are variable interests, the consideration of kick-out and removal rights in determining whether an entity is a VIE, the types of events that trigger the reassessment of whether an entity is a VIE and the expansion of the disclosures previously required. As a result of this guidance we will be required to consolidate the assets, liabilities and operating results of certain VIEs, including certain entities currently accounted for under the equity method of accounting, as further described below. It may also require the Company to deconsolidate certain VIEs that are currently consolidated. The impact of the adoption may be applied retrospectively with a cumulative-effect adjustment to retained earnings as of the beginning of the first year restated, or through a cumulative-effect adjustment on the date of adoption. This guidance is effective for fiscal years beginning after November 15, 2009, or January 1, 2010 for AES. Early adoption is prohibited.

Based on its review to date, the Company has determined that an entity that had not been previously consolidated will be required to be consolidated upon the adoption of the new standard. Cartagena, the Company s generation business in Spain, in which it has a 71% equity interest, is currently accounted for under the equity method of accounting and expected to be consolidated upon the adoption of the new VIE accounting guidance beginning in 2010. Total assets and revenue for Cartagena as of and for the year ended December 31, 2009 were $929 million and $147 million, respectively. The Company is still in the process of quantifying the expected impact of the cumulative adjustment to be recorded upon adoption of the new VIE guidance. AES is in the process of completing its review of the potential impact of the adoption of this guidance and may identify additional entities to consolidate or deconsolidate upon adoption in the first quarter of 2010.

Capital Resources and Liquidity

Overview

As discussed in Highlights of 2009, the Company continued the initiatives started in 2007 to mitigate our refinancing risks and manage our liquidity at the Parent Company as well as our subsidiaries. These efforts included reducing our discretionary growth investments, amending certain of our credit facilities, issuing recourse debt, terminating our senior unsecured credit facility and reducing our planned spending for overhead and development expenses. In addition, in November 2009, the Company announced a binding stock purchase agreement with CIC, to sell 125.5 million shares of AES stock, representing a 15% ownership stake in the Company. The transaction is expected to close in the first half of 2010 and will generate $1.6 billion of new equity to fund future growth opportunities.

As of December 31, 2009, the Company had unrestricted cash and cash equivalents of $1.8 billion and short term investments of $1.6 billion. In addition, we had restricted cash and debt service reserves of $1.0 billion. The Company also had non-recourse and recourse aggregate principal amounts of debt outstanding of $14.4 billion and $5.5 billion, respectively. Of the approximately $1.8 billion of our short-term non-recourse debt, $1.1 billion is presented as current because it is due in the next twelve months and $612 million relates to defaulted debt. We expect such current maturities will be repaid from net cash provided by operating activities of the subsidiary to which the debt relates or through opportunistic refinancing activity or some combination thereof. Approximately $214 million of our recourse debt matures within the next twelve months, which we expect to repay using cash on hand at the Parent Company or through net cash provided by operating activities. See further discussion of Parent Company Liquidity below.

The Company has two types of debt reported on its balance sheet: non-recourse and recourse debt. Non-recourse debt is used to fund investments and capital expenditures for construction and acquisition of our electric power plants, wind projects and distribution facilities at our subsidiaries. Non-recourse debt is generally secured by the capital stock, physical assets, contracts and cash flows of the related subsidiary. The default risk is limited to the respective business and is without recourse to the Parent Company and other subsidiaries. Recourse

Table of Contents

debt is direct borrowings by the Parent Company and is used to fund development, construction or acquisition, including funding for equity investments or to provide loans to the Parent Company s subsidiaries or affiliates. This Parent Company debt is with recourse to the Parent Company and is structurally subordinated to the debt of the Parent Company s subsidiaries or affiliates, except to the extent such subsidiaries or affiliates guarantee the Parent Company s debt.

We rely mainly on long-term debt obligations to fund our construction activities. We have, to the extent available at acceptable terms, utilized non-recourse debt to fund a significant portion of the capital expenditures and investments required to construct and acquire our electric power plants, distribution companies and related assets. Our non-recourse financing is designed to limit cross default risk to the Parent Company or other subsidiaries and affiliates. Our non-recourse long-term debt is a combination of fixed and variable interest rate instruments. Generally, a portion or all of the variable rate debt is fixed through the use of interest rate swaps. In addition, the debt is typically denominated in the currency that matches the currency of the revenue expected to be generated from the benefiting project, thereby reducing currency risk. In certain cases the currency is matched through the use of derivative instruments. The majority of our non-recourse debt is funded by international commercial banks, with debt capacity supplemented by multilaterals and local regional banks. For more information on our long-term debt, see Note 10 Debt to the Consolidated Financial Statements included in Item 8 of this Form 10-K.

Given our long-term debt obligations, the Company is subject to interest rate risk on debt balances that accrue interest at variable rates. When possible, the Company will borrow funds at fixed interest rates or hedge its variable rate debt to fix its interest costs on such obligations. In addition, the Company has historically tried to maintain at least 70% of its consolidated long-term obligations at fixed interest rates, including fixing the interest rate through the use of interest rate swaps. These efforts apply to the notional amount of the swaps compared to the amount of related underlying debt. While the Company believes that this represents an economic hedge, the Company is required to mark-to-market all of these interest rate swaps and other derivatives. Presently, the Parent Company s only exposure to variable interest rate debt relates to indebtedness under its senior secured credit facilities. On a consolidated basis, of the Company s $19.9 billion of total debt outstanding as of December 31, 2009, approximately $4.0 billion bore interest at variable rates that were not subject to a derivative instrument which fixed the interest rate.

In addition to utilizing non-recourse debt at a subsidiary level when available, the Parent Company provides a portion, or in certain instances all, of the remaining long-term financing or credit required to fund development, construction or acquisition of a particular project. These investments have generally taken the form of equity investments or intercompany loans, which are subordinated to the project s non-recourse loans. We generally obtain the funds for these investments from our cash flows from operations, proceeds from the sales of assets and/or the proceeds from our issuances of debt, common stock and other securities. Similarly, in certain of our businesses, the Parent Company may provide financial guarantees or other credit support for the benefit of counterparties who have entered into contracts for the purchase or sale of electricity with our subsidiaries or lenders. In such circumstances, if a subsidiary defaults on its payment or supply obligation, the Parent Company will be responsible for the subsidiary s obligations up to the amount provided for in the relevant guarantee or other credit support. At December 31, 2009, the Parent Company had provided outstanding financial and performance-related guarantees or other credit support commitments to or for the benefit of our subsidiaries, which were limited by the terms of the agreements, of approximately $410 million in aggregate (excluding investment commitments and those collateralized by letters of credit and other obligations discussed below).

As a result of the Parent Company s below investment grade rating, counterparties may be unwilling to accept our general unsecured commitments to provide credit support. Accordingly, with respect to both new and existing commitments, the Parent Company may be required to provide some other form of assurance, such as a letter of credit, to backstop or replace our credit support. The Parent Company may not be able to provide adequate assurances to such counterparties. To the extent we are required and able to provide letters of credit or other collateral to such counterparties, this will reduce the amount of credit available to us to meet our other liquidity needs. At December 31, 2009, we had $204 million in letters of credit outstanding, which operate to guarantee performance relating to certain project development activities and subsidiary operations. These letters of credit were provided under the senior secured credit facility. During 2009, the Company paid letter of credit fees ranging from 1.63% to 13.34% per annum on the outstanding amounts.

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

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

As of December 31, 2009, the Company has approximately $301 million of trade accounts receivable related to some of its generation businesses in Latin America classified as other long-term assets. These consist primarily of trade accounts receivable that, pursuant to amended agreements or government resolutions, have collection periods that extend beyond December 31, 2010, or one year past the balance sheet date. All payments are being received as scheduled and the Company expects all of these receivables to be fully collectible. Additionally, the current portion of these trade accounts receivable was $137 million at December 31, 2009.

AES Solar, one of our equity investments, was formed in March 2008 as a joint venture with Riverstone. Under the terms of the AES Solar joint venture agreement, the Company and Riverstone may each provide up to $500 million of capital through 2013. AES Solar has commitments to purchase solar panels for use in their business and, while the Company is not required to fund AES Solar s obligations, it is possible that if we decide not to fund the joint venture in the future it could impact AES Solar s development plans or operations.

On September 15, 2009, the Company filed a registration statement on Form S-3 with the SEC which will allow the Company to quickly access the capital markets to sell any of a variety of debt and/or equity securities in order to fund refinancings, new investments such as development projects and/or acquisitions, working capital or general corporate purposes. The Form S-3 may also be used to register the resale of securities offered in a private offering of securities.

Capital Expenditures

The Company spent $2.5 billion, $2.9 billion and $2.5 billion on capital expenditures in 2009, 2008 and 2007, respectively. A significant majority of these costs were funded with non-recourse debt consistent with our financial strategy. At December 31, 2009, the Company had a total of $1.1 billion of availability under long-term non-recourse construction credit facilities. As more fully described in *Operational Challenges* and *Global Recession* above, we have taken steps to decrease the amount of new discretionary capital spending. We expect to continue funding projects that are currently in the construction phase using existing capital provided by these non-recourse credit facilities as supplemented by internally generated cash flows, Parent Company liquidity, contribution from existing or new partners and other funding sources. As a result, property, plant and equipment and long-term non-recourse debt are expected to increase over the next few years even though the rate of discretionary spending has been decreased. While we believe we have the resources to continue funding the projects in construction, there can be no assurances that we will continue to fund all these existing construction efforts.

As of December 31, 2009, the Parent Company had $91 million in commitments to invest in our subsidiaries projects under construction and to purchase related equipment, excluding $149 million of such obligations already included in the letters of credits discussed above. The Company expects to fund these net investment commitments over time according to the following schedule: $77 million in 2010, $14 million in 2011 and no investments in 2012. The exact payment schedules will be dictated by the construction milestones. We expect to fund these commitments from a combination of current liquidity and internally generated Parent Company cash flow.

Environmental Capital Expenditures

The Company continues to assess the possible need for capital expenditures associated with international, federal, regional and state regulation of GHG emissions from electric power generation facilities. Legislation and regulations regarding GHG emissions, if enacted, may place significant costs on GHG emissions from fossil fuel-fired electric power generation facilities, particularly coal-fired facilities, and in order to comply, CO_2 emitting facilities may be required to purchase additional GHG emissions allowances or offsets under cap-and-trade programs, pay a carbon tax or install new pollution-control equipment to capture and reduce the amount of GHG emitted from the facilities, in the event that reliable technology to do so is developed. The capital expenditures required to comply with any future GHG legislation and regulations could be significant and unless such costs can be passed on to customers or counterparties, such regulations could impair the profitability of some of the electric power generation facilities operated by our subsidiaries or render certain of them uneconomical to operate, either of which could have a material adverse effect on our consolidated results of operations and financial condition.

With respect to our operations outside the United States, certain of the businesses operated by the Company s subsidiaries are subject to compliance with EU ETS and the Kyoto Protocol in certain countries and other country-specific programs to regulate GHG emissions. 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 because of, among other factors, the cost of GHG emission allowances and/or the ability of our businesses to pass the cost of purchasing such allowances on to customers or counterparties. However, in the event that such counterparties or regulatory authorities challenge our ability to pass these costs on, there can be no assurance that the Company and/or the relevant subsidiary would prevail in any such dispute. Furthermore, even if the Company and/or the relevant subsidiary does prevail, it would be subject to the cost and administrative burden associated with such dispute.

As discussed in Item 1 Business Regulatory Matters *Environmental and Land Use Regulations*, in the United States there presently are no federal laws or regulations regulating GHG emissions, although several legislative proposals are currently under consideration. In 2009, the Company s subsidiaries operated businesses which had total approximate CO_2 emissions of 74.2 million metric tonnes (ownership adjusted). Approximately 39.7 million metric tonnes of the 74.2 million metric tonnes were emitted in the U.S. (both figures ownership adjusted). Approximately 9.7 million metric tonnes were emitted in U.S. states participating in the RGGI. At this time, the federal legislative proposals under consideration applicable to electric power generation facilities generally incorporate market-based cap-and-trade programs which authorize facilities to comply through the acquisition of emissions allowances in lieu of capital expenditures. Certain of the states, either alone or as part of a regional initiative, in which our subsidiaries operate are in the process of developing programs to reduce GHG emissions, primarily CO_2, from the electric power generation facilities through cap-and-trade programs, which would allow CO_2 emitting facilities to comply by purchasing additional GHG emission allowances or offsets under cap-and-trade programs or by installing new pollution-control equipment to capture and reduce the amount of GHG emitted from the facilities, in the event that reliable technology to do so is developed. We believe that legislative or regulatory actions, if enacted, may require a material increase in capital expenditures at our subsidiaries.

Table of Contents

In the future the actual impact on our subsidiaries capital expenditures from any potential federal program to regulate and reduce GHG emissions, if enacted, and the state and regional programs in the process of development, will depend on a number of factors, including among others, the GHG reductions required under any such legislation or regulations, the price and availability of offsets, the extent to which our subsidiaries would be entitled to receive GHG emission allowances without having to purchase them, the quantity of allowances which our subsidiaries would have to purchase, the price of allowances, our subsidiaries ability to recover or pass-through costs incurred to comply with any legislative or regulatory requirements that are ultimately imposed and the use of market-based compliance options such as cap-and-trade programs. Another factor is the success of our climate solutions business, 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 climate solutions business will be successful. Even if our climate solutions business is successful, the level of benefit is unclear with regard to the impact of legislation or regulation concerning GHG emissions.

Potential Sources of Capital

On November 6, 2009 we entered into a stock purchase agreement with an affiliate of CIC in which the Company agreed to sell 125.5 million shares of the Company s common stock for $12.60 per share, for an aggregate purchase price of $1.58 billion. After this sale, these shares will represent approximately a 15% interest in the Company. The closing of the sale is subject to certain regulatory approvals and is expected to close in the first half of 2010. Additionally, in November 2009, the Company announced the signing of a letter of intent with an affiliate of CIC to raise an additional $571 million of equity for an approximate 35% interest in our wind generation business.

In December 2009, the Company announced agreements to sell our entire interests in our businesses in Oman and Pakistan for approximately $200 million. These deals are expected to close in the first half of 2010.

Consolidated Cash Flows

At December 31, 2009, cash and cash equivalents increased $928 million from December 31, 2008 to $1.8 billion. The increase in cash and cash equivalents was due to $2.2 billion of cash provided by operating activities, $1.9 billion of cash used for investing activities, $610 million of cash provided by financing activities and the favorable effect of foreign currency exchange rates on cash of $22 million.

At December 31, 2008, cash and cash equivalents decreased $1.2 billion from December 31, 2007 to $881 million. The decrease in cash and cash equivalents was due to $2.2 billion of cash provided by operating activities, $3.6 billion of cash used for investing activities, $362 million of cash provided by financing activities and the unfavorable effect of foreign currency exchange rates on cash of $96 million.

				$ Change	
	2009	2008	2007	2009 vs. 2008	2008 vs. 2007
			(in millions)		
Net cash provided by operating activities	$ 2,213	$ 2,161	$ 2,354	$ 52	$ (193)
Net cash used in investing activities	$ 1,917	$ 3,581	$ 1,970	$ (1,664)	$ 1,611
Net cash provided by financing activities	$ 610	$ 362	$ 244	$ 248	$ 118

Operating Activities

Net cash provided by operating activities increased $52 million to $2.2 billion during 2009 compared to $2.2 billion during 2008. This net increase was primarily due to the following:

an increase of $238 million at our Latin American Generation businesses due to improved working capital management; and an increase of $188 million at our Asia Generation businesses due to improved working capital management and improved gross margin;

an increase of $85 million at our Europe Generation businesses primarily due to the collection of the $80 million Kazakhstan management performance incentive bonus in the first quarter 2009; offset by

a decrease of $391 million at our Latin American Utilities businesses due to increased working capital requirements, including the payment on the settlement of a swap agreement, increased tax payments associated with a tax amnesty program and increased payments related to the settlement of contingencies and energy purchases, partially offset by increased operating results; and

a decrease of $77 million at our North America Generation businesses, primarily due to reduced operating results.

Investing Activities

Net cash used for investing activities decreased $1.7 billion to $1.9 billion during 2009 compared to net cash used of $3.6 billion during 2008. This decrease was largely attributable to the following:

a decrease of $330 million in capital expenditures to $2.5 billion primarily from an overall decrease in expenditures of $227 million at Maritza in Bulgaria, $143 million for our U.S. wind generation projects, $74 million in Brazil, and $64 million in Jordan, partially offset by an increase of $161 million for plant construction at Gener;

a decrease of $1.1 billion of acquisitions as a result of no acquisitions in 2009. In 2008, acquisitions consisted primarily of the purchase of Masinloc, a 660 gross MW coal-fired thermal power generation facility purchased during the second quarter of 2008 for approximately $930 million, as discussed in Note 22 Acquisitions and Dispositions to the Consolidated Financial Statements included in Item 8 of this Form 10-K. We also acquired Mountain View in the U.S. during the first quarter of 2008;

a decrease of $1.3 billion in proceeds from the sales of businesses to $2 million in 2009. The proceeds in 2008 included $1.1 billion from the sale of Ekibastuz and Maikuben, $171 million in net proceeds from the sale of a 10% ownership interest in AES Gener and $73 million in proceeds from the sale of Jiaozuo;

a decrease of $597 million from the sale of short-term investments, net of purchases, including increases in net sales of $553 million at our Brazilian subsidiaries, to fund dividend payments. In addition, there was an increase in net sales of $184 million and $78 million at Alicura in Argentina and Masinloc, respectively, due to maturities of investments and an increase in net sales of $79 million at IPALCO as a result of IPL s variable rate demand notes being successfully remarketed. This was partially offset by a $317 million increase in net purchases at Gener related to the purchase of time deposits;

a $302 million decrease in restricted cash in 2009 including decreases of $216 million at Gener from the use of the proceeds raised in the fourth quarter of 2008 that were restricted to use only for the purchase of additional shares in the first quarter of 2009 to fund future construction, $72 million at Chigen used for debt repayment, and $41 million in New York, partially offset by an increase of $39 million at Masinloc; and

a $134 million reduction in cash used for advances to affiliate and equity investments, loan advances and other investing activities.

Table of Contents

Financing Activities:

Net cash provided by financing activities increased $248 million to $610 million during 2009 compared to $362 million during 2008. This increase was primarily attributable to the following:

- a decrease in net borrowings under revolving credit facilities of $287 million primarily from increased net repayments of $172 million at Lal Pir/Pak Gen in Pakistan due to off-taker collections, $64 million due to increased net repayments at IPALCO to pay off a line of credit in 2009, and a $22 million reduction in net borrowings at Panama for project financing;

- a decrease of $283 million from issuances of recourse and non-recourse debt primarily due to decreases in the issuance of non-recourse debt of $603 million at Masinloc, $262 million at IPL, and $10 million at our wind development projects at our U.S. businesses in 2009. These decreases were partially offset by increases in the issuance of non-recourse debt of $347 million at Eletropaulo and $316 million at Gener;

- a $1,135 million decrease in repayments of recourse debt and non-recourse debt, predominantly due to decreases in repayments of recourse debt of $883 million at the Parent Company and non-recourse debt of $257 million at IPL; partially offset by

- a $249 million increase in distributions to noncontrolling interests, primarily due to $120 million higher dividends distributions at Eletropaulo and $110 million higher dividends declared to noncontrolling interests at Brasiliana Energia; and

- a $220 million decrease in contributions from noncontrolling interests primarily due to a reduction of $201 million at our U.S. wind generation projects.

Contractual Obligations

A summary of our contractual obligations, commitments and other liabilities as of December 31, 2009 is presented in the table below (in millions):

Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**5 years and more**	**Other**	**Footnote Reference**
Debt Obligations[(1)]	$ 19,841	$ 1,960	$ 2,588	$ 3,687	$ 11,606	$	10
Interest Payments on Long- Term Debt[(2)]	10,254	1,405	2,595	2,114	4,140		n/a
Capital Lease Obligations[(3)]	204	14	25	19	146		11
Operating Lease Obligations[(4)]	477	55	80	78	264		11
Sale Leaseback Obligations[(5)]	704	41	87	93	483		11
Electricity Obligations[(6)]	55,198	2,403	5,794	5,603	41,398		11
Fuel Obligations[(7)]	10,148	1,681	1,813	1,285	5,369		11
Other Purchase Obligations[(8)]	17,879	2,217	2,500	1,748	11,414		11
Other Long-term Liabilities Reflected on AES s Consolidated Balance Sheet under GAAP[(9)]	810	66	186	75	390	93	n/a
Total	$ 115,515	$ 9,842	$ 15,668	$ 14,702	$ 75,210	$ 93	

(1) Includes recourse and non-recourse debt presented on the Consolidated Financial Statements. Non-recourse debt borrowings are not a direct obligation of AES, the Parent Company. Recourse debt represents the direct borrowings of AES, the Parent Company. See

Note 10 Debt to the Consolidated Financial Statements included in Item 8 of this Form 10-K which provides additional disclosure regarding these obligations. These amounts exclude capital lease obligations which are included in the capital lease category, see (3) below.

(2) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2009 and do not reflect anticipated future refinancing, early redemptions or new debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2009.

(3) Several AES subsidiaries have leases for operating and office equipment and vehicles that are classified as capital leases within Property, Plant and Equipment. Minimum contractual obligations include $129 million of imputed interest.
(4) The Company was obligated under long-term non-cancelable operating leases, primarily for office rental and site leases. These amounts exclude amounts related to the sale/leaseback discussed below in item (5).
(5) Sale/Leaseback Obligations represent a sales/leaseback with operating lease treatment at one of our New York subsidiaries.
(6) Operating subsidiaries of the Company have entered into contracts for the purchase of electricity from third parties.
(7) Operating subsidiaries of the Company have entered into fuel purchase contracts subject to termination only in certain limited circumstances.
(8) Amounts relate to other contractual obligations where the Company has an enforceable and legally binding agreement to purchase goods or services that specifies all significant terms, including: quantity, pricing, and approximate timing. These amounts include planned capital expenditures that are contractually obligated.
(9) These amounts do not include current liabilities on the Consolidated Balance Sheet except for the current portion of uncertain tax obligations. See the indicated notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information on the items excluded. Derivatives (See Note 5 Derivative Instruments) and incentive compensation are excluded as the Company is not able to reasonably estimate the timing or amount of the future payments. In addition, the amounts do not include: (1) regulatory liabilities (See Note 9 Regulatory Assets and Liabilities), (2) contingencies (See Note 12 Contingencies), (3) pension and other post retirement employee benefit liabilities (see Note 13 Benefit Plans) or (4) any taxes (See Note 20 Income Taxes) except for uncertain tax obligations. Noncurrent uncertain tax obligations are reflected in the Other column of the table above as the Company is not able to reasonably estimate the timing of the future payments.

Parent Company Liquidity

The following discussion of Parent Company Liquidity has been included because we believe it is a useful measure of the liquidity available to The AES Corporation, or the Parent Company, given the non-recourse nature of most of our indebtedness. Parent Company liquidity as outlined below is a non-GAAP measure and should not be construed as an alternative to cash and cash equivalents which are determined in accordance with GAAP, as a measure of liquidity. Cash and cash equivalents are disclosed in the Consolidated Statements of Cash Flows and the parent only unconsolidated statements of cash flows in Schedule I of this Form 10-K. Parent Company liquidity may differ from similarly titled measures used by other companies. The principal sources of liquidity at the Parent Company level are:

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

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

- interest;
- principal repayments of debt;
- acquisitions;
- construction commitments;
- other equity commitments;

taxes; and

Parent Company overhead and development costs.

135

Table of Contents

The Company defines Parent Company Liquidity as cash available to the Parent Company plus available borrowings under existing credit facilities. The cash held at qualified holding companies represents cash sent to subsidiaries of the Company domiciled outside of the U.S. Such subsidiaries have no contractual restrictions on their ability to send cash to the Parent Company. Parent Company Liquidity is reconciled to its most directly comparable U.S. GAAP financial measure, cash and cash equivalents at December 31, 2009 and 2008 as follows:

Parent Company Liquidity	**2009**	**2008**
	(in millions)	
Cash and cash equivalents	$ 1,809	$ 881
Less: Cash and cash equivalents at subsidiaries	1,132	634
Parent and qualified holding companies cash and cash equivalents	677	247
Commitments under Parent credit facilities	785	1,350
Less: Borrowings and letters of credit under the credit facilities	(204)	(207)
Borrowings available under Parent credit facilities	581	1,143
Total Parent Company Liquidity	$ 1,258	$ 1,390

Recourse Debt Transactions:

On March 26, 2009, the Parent Company and certain subsidiary guarantors amended the Parent Company s existing senior secured credit facility pursuant to the terms of Amendment No. 1 (Amendment No. 1) to the Fourth Amended and Restated Credit and Reimbursement Agreement, dated as of July 29, 2008 (the senior secured credit facility). The senior secured credit facility previously included a $200 million term loan facility maturing on August 10, 2011 and a $750 million revolving credit facility maturing on June 23, 2010 (the revolving credit facility).

The principal modification set forth in Amendment No. 1 was a one-year extension of $570 million of revolving credit facility commitments from an original maturity date of June 23, 2010 to July 5, 2011. In addition, certain lenders determined that they would increase their commitment under the revolving credit facility by $35 million from March 26, 2009 through July 5, 2011. Accordingly, Amendment No. 1 increased the size of the revolving credit facility from $750 million to $785 million through June 23, 2010. From June 23, 2010 through July 5, 2011, the revolving credit facility size will be $605 million. No modifications were made to the amount or maturity date of the $200 million term loan facility.

The extended commitments from this amendment were subject to new pricing that included an upfront fee of 1.25% for participating in the extensions and an increase in undrawn commitment fees from 50 to 100 basis points. The annual interest rate on the drawn loans was also increased by 200 basis points to LIBOR plus 3.50%. Pricing and all other material terms remain unchanged for the revolving credit facility commitments which have not been extended.

On April 2, 2009 the Parent Company issued $535 million aggregate principal amount of 9.75% senior unsecured notes due 2016 in a private placement. The notes were priced at a discount to yield 11%. Subsequently, the Parent Company allocated a substantial portion of the proceeds to voluntarily reduce the size of its $600 million senior unsecured credit facility among the Parent Company, Merrill Lynch Bank USA and the banks party thereto (the senior unsecured credit facility). The majority of the letters of credit issued under the facility supported a project under construction in Bulgaria. On October 7, 2009, the Parent Company voluntarily reduced all of the remaining commitments available under the senior unsecured credit facility and terminated the facility agreement. As a result of the termination, the Company recognized a foreign currency transaction gain of $20 million in the fourth quarter of 2009 related to the sale of Euro purchased as collateral at the inception of the facility. The outstanding letters of credit under the senior unsecured credit facility were transferred to the senior secured credit facility.

Table of Contents

Recourse Debt:

Our recourse debt at year-end was approximately $5.5 billion, $5.2 billion, and $5.6 billion in 2009, 2008 and 2007, respectively. The following table sets forth our Parent Company contingent contractual obligations as of December 31, 2009:

Contingent contractual obligations	Amount (in millions)	Number of Agreements	Maximum Exposure Range for Each Agreement (in millions)
Guarantees	$ 410	31	<$ 1 - $53
Letters of credit under the senior secured credit facility	204	26	<$ 1 - $120
Total	$ 614	57	

As of December 31, 2009, the Company had $91 million of commitments to invest in subsidiaries under construction and to purchase related equipment, excluding $149 million of such obligations already included in the letters of credit discussed above. The Company expects to fund these net investment commitments over time according to the following schedule: $77 million in 2010, $14 million in 2011 and no investments in 2012. The exact payment schedules will be dictated by the construction milestones. We expect to fund these commitments from a combination of current liquidity and internally generated Parent Company cash flow.

We have a diverse portfolio of performance related contingent contractual obligations. These obligations are designed to cover potential risks and only require payment if certain targets are not met or certain contingencies occur. The risks associated with these obligations include change of control, construction cost overruns, subsidiary default, political risk, tax indemnities, spot market power prices, supplies support and liquidated damages under power sales agreements for projects in development, in operation and under construction. While we do not expect that we will be required to fund any material amounts under these contingent contractual obligations during 2010 or beyond, many of the events which would give rise to such obligations are beyond our control. We can provide no assurance that we will be able to fund our obligations under these contingent contractual obligations if we are required to make substantial payments thereunder.

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

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

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

Table of Contents

- maintenance of certain financial ratios; and
- financial and other reporting requirements.

As of December 31, 2009, we were in compliance with these covenants.

Non-Recourse Debt:

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

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

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

Some of our subsidiaries are currently in default with respect to all or a portion of their outstanding indebtedness. The total non-recourse debt classified as current in the accompanying Consolidated Balance Sheets amounts to $1.8 billion. The portion of current debt related to such defaults was $612 million at December 31, 2009, all of which was non-recourse debt related to four subsidiaries Sonel, Jordan, Kelanitissa and Ebute.

None of the subsidiaries that are currently in default are subsidiaries that currently meet the applicable definition of materiality in AES s corporate debt agreements in order for such defaults to trigger an event of default or permit acceleration under such indebtedness. At December 31, 2009, none of our subsidiaries that are currently in default met the definition of material subsidiary under our recourse senior secured credit facility or other debt agreements. However, as a result of additional dispositions of assets, other significant reductions in asset carrying values or other matters in the future that may impact our financial position and results of operations or the financial position of the individual subsidiary, it is possible that one or more of these subsidiaries could fall within the definition of a material subsidiary and thereby upon an acceleration trigger an event of default and possible acceleration of the indebtedness under the AES Parent Company s outstanding debt securities.

Off-Balance Sheet Arrangements

In May 1999, one of our subsidiaries acquired six electric generating plants from New York State Electric and Gas. Concurrently, the subsidiary sold two of the plants to an unrelated third party for $666 million and simultaneously entered into a leasing arrangement with the unrelated party. In May 2007, the subsidiary purchased a portion of the lessor s interest in a trust estate that holds the leased plants. Future minimum lease commitments under the lease agreement have been reduced by the subsidiary s interest in the plants. We have accounted for this transaction as a sale/leaseback transaction with operating lease treatment. We expense periodic lease payments as incurred, which amounted to $34 million, $34 million and $42 million for the years ended December 31, 2009, 2008 and 2007, respectively. We are not subject to any additional liabilities or contingencies if the arrangement terminates and we believe that the dissolution of the off-balance sheet arrangement would

138

have minimal effects on our operating cash flows. The terms of the lease include restrictive covenants such as the maintenance of certain coverage ratios. Historically, the plants have satisfied the restrictive covenants of the lease and there are no known trends or uncertainties that would indicate that the lease will be terminated early. See Note 11 Commitments to the Consolidated Financial Statements included in Item 8 of this Form 10-K for a more complete discussion of this transaction.

IPL, a consolidated subsidiary of the Company, formed IPL Funding Corporation (IPL Funding) in 1996 as a special purpose entity to purchase, on a revolving basis, the receivables originated by IPL. IPL Funding is not a qualified special purpose entity and is consolidated by IPL and IPALCO. IPL Funding entered into a sale facility with unrelated parties (the Purchasers) pursuant to which the Purchasers agree to purchase from IPL Funding, on a revolving basis, interests in the pool of receivables purchased from IPL up to the lesser of (1) an amount determined pursuant to the sale facility that takes into account certain eligibility requirements and reserves relating to the receivables, or (2) $50 million. Historically that amount has remained at $50 million, but during the fourth quarter of 2009, IPL s eligible receivables balance was below $50 million and IPL was required to repay the Purchasers the shortfall, which was approximately $10 million as of December 31, 2009. As collections reduce accounts receivable included in the pool, IPL Funding sells ownership interests in additional receivables acquired from IPL to return the ownership interests sold to the maximum amount permitted by the sale facility. During the second quarter of 2009, this agreement was extended through May 25, 2010. Accounts receivable on the Company s consolidated balance sheets are stated net of the $40 million and $50 million sold as of December 31, 2009 and 2008, respectively and include $88 million and $87 million as of December 31, 2009 and 2008, respectively, related to IPL Funding s accounts receivable.

IPL retains servicing responsibilities for its role as a collection agent on the amounts due on the sold receivables. However, the Purchasers assume the risk of collection on the purchased receivables without recourse to IPL in the event of a loss. While no direct recourse to IPL exists, it risks loss in the event collections are not sufficient to allow for full recovery of its retained interests. No servicing asset or liability is recognized since the servicing fee paid to IPL approximates a market rate.

The carrying values of the retained interests are determined by allocating the carrying value of the receivables between the assets sold and the interests retained based on relative fair value. The key assumptions in estimating fair value are credit losses, the selection of discount rates and expected receivables turnover rate. The hypothetical effect on the fair value of the retained interests assuming both a 10% and a 20% unfavorable variation in credit losses or discount rates is not material due to the short turnover of receivables and historically low credit loss history.

The losses recognized on the sales of receivables were $1 million, $2 million and $3 million for the years ended December 31, 2009, 2008 and 2007, respectively. These losses are included in other expense on the consolidated statements of operations. The amount of the losses recognized depends on the previous carrying amount of the financial assets involved in the transfer, allocated between the assets sold and the interests that continue to be held by the transferor based on their relative fair value at the date of transfer, and the proceeds received.

There were no proceeds from new securitizations for each of the years ended December 31, 2009 and 2008. IPL Funding pays IPL annual service fees totaling $1 million, which is financed by capital contributions from IPL to IPL Funding.

The following table shows the receivables sold and retained interests as of December 31, 2009 and 2008:

	2009	2008
	(in millions)	
Receivables at IPL Funding	$ 128	$ 137
Less: Retained interests	88	87
Net receivables sold	$ 40	$ 50

Table of Contents

The following table shows the cash flows for the years ended December 31, 2009, 2008 and 2007:

	2009	2008	2007
		(in millions)	
Cash proceeds from interest retained	$ 690	$ 623	$ 541
Cash proceeds from sold receivables	$ 315	$ 363	$ 419

IPL and IPL Funding provide certain indemnities to the Purchasers, including indemnification in the event that there is a breach of representations and warranties made with respect to the purchased receivables. IPL Funding and IPL each have agreed to indemnify the Purchasers on an after-tax basis for any and all damages, losses, claims, liabilities, penalties, taxes, costs and expenses at any time imposed on or incurred by the indemnified parties arising out of, or otherwise relating to, the sale facility, subject to certain limitations as defined in the sale facility.

Under the sale facility, if IPL fails to maintain certain financial covenants including, but not limited to interest coverage and debt to capital ratios, it would constitute a termination event. As of December 31, 2009, IPL was in compliance with such covenants. In the event that IPL s credit rating falls below a threshold identified in the sale facility, the facility agent has the ability to replace IPL as the collection agent and declare a lock-box event. Under a lock-box event or a termination event, the facility agent has the ability to require all proceeds of purchased receivables of IPL to be directed to lock-box accounts within 45 days of notifying IPL. In addition, a termination event would also give the facility agent the option to take control of the lock-box account, give the Purchasers the option to discontinue the purchase of new receivables, and require all proceeds to be used to reduce the Purchaser s investment and pay other amounts owed to the Purchasers and the facility agent. This could reduce the operating capital available to IPL by the aggregate amount of any purchased receivables up to $50 million.

Table of Contents

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK
Overview Regarding Market Risks

We are a global company in the power generation and distribution businesses. We own and/or operate power plants to generate and sell power to wholesale customers. We also own and/or operate utilities to distribute, transmit and sell electricity to end-user customers. Our primary market risk exposure is to the price of commodities particularly electricity, oil, natural gas, coal and environmental credits. We operate in multiple countries and as such we are exposed to volatility in the exchange rate between our functional currency, the U.S. dollar and currencies of the countries in which we operate. We are also exposed to interest rate fluctuations due to our issuance of debt and related financial instruments.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the price of electricity, fuels and environmental credits. Although we primarily consist of businesses with long-term contracts or retail sales concessions, a portion of our current and expected future revenues are derived from businesses without significant long-term revenue or supply contracts. These businesses subject our operational results to the volatility of prices for electricity, fuels and environmental credits in competitive markets. We employ risk management strategies to hedge our financial performance against the effects of fluctuations in energy commodity prices. The implementation of these strategies can involve the use of physical and financial commodity contracts, futures, swaps and options.

When hedging the output of our generation assets, we have PPAs or other hedging instruments that lock in the spread per MWh between the cost of fuel to generate a unit of electricity and the price at which the electricity can be sold. The portion of our sales and fuel purchases that are not subject to such agreements will be exposed to commodity price risk.

AES businesses will see variance in variable margin performance as global commodity prices shift. For 2010, we project approximate pre-tax earnings exposure of $15 million for a $10/barrel move in oil, $50 million for $1/mmbtu move in natural gas and $20 million for a $10/ton shift in coal prices. These estimates exclude correlation. For example, a decline in oil or natural gas prices can be accompanied by a decline in coal price if commodity prices are correlated. In aggregate, the corporation s downside exposure occurs with lower oil, lower natural gas, and higher coal prices. Exposures at individual businesses will change as new contracts or financial hedges are executed.

Commodity prices affect our businesses differently depending on the local market characteristics and risk management strategies. Generating costs can be directly affected by movements in prices of natural gas, oil, and coal. Spot power prices and contract indexation provisions are affected by these same commodity price movements. We have some natural offsets across our businesses such that low commodity prices may benefit certain businesses and be a cost to others. Variance is not perfectly linear or symmetric. The sensitivities are affected by a number of non-market, or indirect market factors. Examples of these factors include hydrology, energy market supply/demand balances, regional fuel supply issues, and regulator interventions such as price caps. Operational flexibility changes the shape of our sensitivities. For instance, power plants may reduce dispatch in low market environments limiting downside exposure. Volume variation also affects our commodity exposure. The volume sold under contracts or retail concessions can vary based on weather and economic conditions resulting in a higher or lower volume of sales in spot markets. Thermal unit availability and hydrology can affect the generation output available for sale and can affect the marginal unit setting power prices.

Our larger contributors to commodity risk include the North American businesses of Eastern Energy, Deepwater and wholesale power sales of IPL; the Latin American businesses in Chile, Argentina, the Dominican Republic and Panama and the Masinloc business in Asia.

In North America, the variance is due to dark spread to the extent a portion of sales are un-hedged. Natural gas-fired generators set power prices for many periods so higher natural gas prices expand margins and higher coal prices cause a decline. The positive impact on margins will be moderated if natural-gas fired generators set the market price only during certain peak periods. IPL sells power at wholesale once retail demand is served so retail sales demand may affect commodity exposure.

In Chile, we own assets and have associated contracts in both the central and northern regions of the country. Contracts tend to be long-term and indexed to fuel which limits commodity risk. Oil-fired generators set power prices for some periods so lower oil prices can erode margins on spot power market sales. Gener has been adding coal-fired generation in response to the Argentine gas crisis increasing its exposure to dark spreads on un-hedged volumes. Gener also owns natural gas/diesel, hydropower and biomass generating facilities.

In other Latin American markets, the businesses have commodity exposure on open volumes. In Panama and Colombia, we own hydropower assets so contracts are not indexed to fuel. In the Dominican Republic, we own natural gas-fired and coal-fired assets and both contract and spot prices may move with commodity prices. In Argentina, prices are set according to government rules that result in commodity exposure based on the spread between cost of coal generation and oil-fired generation and other factors.

Our Masinloc business is a coal-fired facility which hedges its output through medium term contracts that are indexed to fuel prices. Low oil prices may be a driver of margin compression since oil affects spot power sale prices.

Foreign Exchange Rate Risk

In the normal course of business, we are exposed to foreign currency risk and other foreign operations risk that arise from investments in foreign subsidiaries and affiliates. A key component of this risk stems from the fact that some of our foreign subsidiaries and affiliates utilize currencies other than our consolidated reporting currency, the U.S. Dollar. Additionally, certain of our foreign subsidiaries and affiliates have entered into monetary obligations in U.S. Dollar or currencies other than their own functional currencies. Primarily, we are exposed to changes in the exchange rate between the U.S. Dollar and the following currencies: Argentine Peso, Brazilian Real, British Pound, Cameroonian Franc, Chilean Peso, Colombian Peso, Euro, Kazakhstani Tenge, Mexican Peso, and Philippine Peso. These subsidiaries and affiliates have attempted to limit potential foreign exchange exposure by entering into revenue contracts that adjust to changes in foreign exchange rates. We also use foreign currency forwards, swaps and options, where possible, to manage our risk related to certain foreign currency fluctuations.

During 2009, we entered into hedges to partially mitigate the exposure of earnings translated into U.S. Dollar to foreign exchange volatility. Given a 10% U.S. Dollar appreciation, 2010 pre-tax earnings attributable to foreign subsidiaries exposed to movements in the exchange rates of the Argentinean Peso, Brazilian Real, Colombian Peso, and Euro (the earnings attributable to subsidiaries exposed to Cameroonian Franc movements are included under Euro due to the fixed exchange rate of Cameroonian Franc to Euro) relative to the U.S. Dollar are projected to be $5 million, $35 million, $9 million and $10 million respectively. Total AES pre-tax earnings for 2010 would be reduced by approximately $60 million on a correlated basis. These numbers have been produced by applying a one-time 10% U.S. Dollar appreciation to exposed pre-tax earnings for 2010 coming from subsidiaries where the local currency is either not the U.S. Dollar or is not exhibiting the characteristics of a peg or managed float relative to the U.S. Dollar, net of impact of outstanding hedges and holding all other variables constant. The numbers presented above are net of any transactional gains/losses and the correlation effect is based on historical foreign exchange rate movement over a period equal in length to the period over which the simulated move occurs. These sensitivities may change in the future as new hedges are executed or existing hedges unwound. Additionally, updates to the forecasted pre-tax earnings exposed to foreign exchange risk may result in further modification.

Interest Rate Risks

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

Decisions on the fixed-floating debt ratio are made to be consistent with the risk factors faced by individual businesses or plants. Depending on whether a plant s capacity payments or revenue stream is fixed or varies with inflation, we partially hedge against interest rate fluctuations by arranging fixed-rate or variable-rate financing. In certain cases, particularly for non-recourse financing, we execute interest rate swap, cap and floor agreements to effectively fix or limit the interest rate exposure on the underlying financing.

As of December 31, 2009, the portfolio s 2010 pre-tax earnings exposure (adjusted to reflect non-controlling interests) to a 100 basis point increase in Brazilian Real, British Pound, Colombian Peso, Euro, Hungarian Forint, Philippine Peso, Ukraine Hryvnia and U.S. Dollar interest rates is approximately $20 million. This number is based on the impact of a one-time, 100 basis point increase in interest rates on interest expense for Brazilian Real, British Pound, Colombian Peso, Euro, Hungarian Forint, Philippine Peso, Ukraine Hryvnia and U.S. Dollar-denominated debt for 2010, which together account for more than 99% of the portfolio s floating-rate debt which is primarily non-recourse financing. The numbers do not take into account the historical correlation between these interest rates.

Value at Risk

We have performed a company wide value at risk analysis (VaR) of all of our material financial assets, liabilities and derivative instruments. VaR measures the potential loss in a portfolio s value due to market volatility, over a specified time horizon, stated with a specific degree of probability and is calculated based on volatilities and correlations of the different risk exposures of the portfolio. The quantification of market risk using VaR provides a consistent measure of risk across diverse markets and instruments. VaR is not necessarily indicative of actual results that may occur. Additionally, VaR represents changes in fair value of financial instruments and not the economic exposure to AES and its affiliates.

Because of the inherent limitations of VaR, including those specific to Analytic VaR, in particular the assumption that values or returns are normally distributed, we rely on VaR as only one component in our risk assessment process. In addition to using VaR measures, we perform sensitivity and scenario analyses to estimate the economic impact of market changes to our portfolio of businesses. We use these results to complement the VaR methodology.

In addition, the relevance of the VaR described herein as a measure of economic risk, is limited and needs to be considered in light of the underlying business structure. Embedded derivatives are not appropriately measured here and are excluded since VaR is not representative of the overall contract valuation. The VaR calculation incorporates numerous variables that could impact the fair value of our instruments, including interest rates, foreign exchange rates and commodity prices, as well as correlation within and across these variables. The interest rate component of VaR is due to changes in the fair value of our fixed rate debt instruments and interest rate swaps. These instruments themselves would expose a holder to market risk; however, utilizing these fixed rate debt instruments as part of a fixed price contract generation business mitigates the overall exposure to interest rates. Similarly, our foreign exchange rate sensitive instruments are often part of businesses which have revenues denominated in the same currency, thus offsetting the exposure.

We express Analytic VaR herein as a dollar amount of the potential loss in the fair value of our portfolio based on a 95% confidence level and a one-day holding period. Our commodity analysis is a VaR calculation within the commodity transaction management system and is reported for financially settled derivative products at our Eastern Energy business in New York State and physically settled derivative products at AES Deepwater, Inc. in Pasadena, Texas as these are the only businesses with commodity transactions that are deemed derivatives. These commodity transactions are marked to market on a daily basis. Collateral is then posted or recalled for any changes in exposures at Eastern Energy. However, not every transaction requires Eastern Energy to post collateral, as several counterparties have caps defined in their transaction agreements. For those counterparties that do require Eastern Energy to post collateral, two facilities that are non-recourse to The AES Corporation in the amounts of $75 million and $350 million are used to issue letters of credit. As of December 31, 2009, $19 million and $68 million have been utilized under these facilities. AES Deepwater is not required to post collateral for these commodity transactions.

One Day VaR	December 31, 2009	September 30, 2009	June 30, 2009	March 31, 2009	December 31, 2008	December 31, 2007
			(in millions)			
Foreign Exchange	$ 66	$ 58	$ 78	$ 78	$ 125	$ 57
Interest Rate	$ 108	$ 129	$ 155	$ 176	$ 188	$ 137
Commodity	$ 8	$ 7	$ 4	$ 4	$ 7	$ 16

For the year ended December 31, 2009, our one-day VaR at fourth quarter end for foreign exchange rate-sensitive instruments was $66 million compared to $125 million for the year ended December 31, 2008. This amount includes foreign currency denominated debt and hedge instruments. The decrease in VaR was driven primarily by the decline in volatilities of currencies in our portfolio, notably the Brazilian Real, Chilean Peso, Euro and Philippine Peso.

For the year ended December 31, 2009, our one-day VaR at fourth quarter end for interest rate-sensitive instruments was $108 million compared to $188 million for the year ended December 31, 2008. This amount includes the financial instruments that serve as hedges and the underlying hedged items. The largest component of interest rate VaR is from U.S. dollar-denominated, fixed-rate debt and the decrease in VaR was due to the decrease in volatilities of bond yields.

For the year ended December 31, 2009, our one-day VaR at fourth quarter end for commodity price sensitive instruments was $8 million compared to $7 million for the year ended December 31, 2008. For Eastern Energy, these amounts include the financial instruments that serve as hedges and do not include the underlying physical assets or contracts that are not permitted to be settled in cash. The VaR for Eastern Energy was $7 million compared to $7 million for the year ended December 31, 2008. For Deepwater, the reported VaR includes the physically settled derivative products that serve as hedges. The VaR for Deepwater was $450,000. Starting in the second quarter of 2009, the commodity VaR disclosure includes both AES Eastern Energy and AES Deepwater.

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

ON THE FINANCIAL STATEMENTS

The Board of Directors and Stockholders of The AES Corporation:

We have audited the accompanying consolidated balance sheets of The AES Corporation and its subsidiaries as of December 31, 2009 and December 31, 2008, and the related consolidated statements of operations, stockholders equity and cash flows for each of the two years in the period ended December 31, 2009. Our audits also included the financial statement schedules for each of the two years in the period ended December 31, 2009 listed in the accompanying Index to Item 15(a). These financial statements and schedules are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of The AES Corporation and its subsidiaries at December 31, 2009 and 2008, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedules for each of the two years in the period ended December 31, 2009, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), The AES Corporation s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2010 expressed an unqualified opinion thereon.

/s/: Ernst & Young LLP

McLean, Virginia

February 25, 2010

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

ON THE FINANCIAL STATEMENTS

To the Board of Directors and Stockholders of

The AES Corporation

Arlington, VA

We have audited the accompanying consolidated statements of operations, changes in equity, and cash flows of The AES Corporation and subsidiaries (the Company) for the year ended December 31, 2007. Our audit also included the 2007 information in the financial statement schedules listed in the index on page S-1. These financial statements and financial statement schedules are the responsibility of the Company s management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statement. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the results of operations and cash flows of The AES Corporation and subsidiaries for the year ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As also discussed in Notes 1, 15, 17 and 21 to the consolidated financial statements, the accompanying 2007 financial statements have been adjusted for the retroactive application of accounting for noncontrolling interests, which was adopted by the Company on January 1, 2009, and for the changes in reportable segments that occurred in 2009.

/s/ Deloitte & Touche LLP

McLean, Virginia

March 14, 2008

(February 25, 2010 as to the Discontinued Operations and Reclassification section of Note 1 and the December 2009 paragraph of Note 21, and the changes in reportable segments described in Note15, September 11, 2009 as to the effects of the adoption of a new accounting standard described in the Noncontrolling Interests section of Note 1, the first paragraph of Note 17, and changes in reportable segments, and February 26, 2009 as to the December 2008 paragraph of Note 21).

Table of Contents

THE AES CORPORATION

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 2009 AND 2008

	2009	2008
	(in millions)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,809	$ 881
Restricted cash	407	722
Short-term investments	1,648	1,382
Accounts receivable, net of allowance for doubtful accounts of $290 and $253, respectively	2,152	2,064
Inventory	569	547
Receivable from affiliates	24	31
Deferred income taxes current	218	178
Prepaid expenses	162	175
Other current assets	1,558	1,102
Current assets of discontinued and held for sale businesses	240	234
Total current assets	8,787	7,316
NONCURRENT ASSETS		
Property, Plant and Equipment:		
Land	1,111	854
Electric generation, distribution assets and other	27,462	24,002
Accumulated depreciation	(8,920)	(7,385)
Construction in progress	4,644	3,408
Property, plant and equipment, net	24,297	20,879
Other Assets:		
Deferred financing costs, net of accumulated amortization of $297 and $264, respectively	384	364
Investments in and advances to affiliates	1,157	901
Debt service reserves and other deposits	595	634
Goodwill	1,299	1,421
Other intangible assets, net of accumulated amortization of $223 and $186, respectively	510	500
Deferred income taxes noncurrent	604	567
Other	1,551	1,694
Noncurrent assets of discontinued and held for sale businesses	351	530
Total other assets	6,451	6,611
TOTAL ASSETS	$ 39,535	$ 34,806
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 1,217	1,033
Accrued interest	271	244
Accrued and other liabilities	3,017	2,640
Non-recourse debt current	1,759	917
Recourse debt current	214	154
Current liabilities of discontinued and held for sale businesses	143	194
Total current liabilities	6,621	5,182
LONG-TERM LIABILITIES		

Non-recourse debt noncurrent	12,642	11,625
Recourse debt noncurrent	5,301	4,994
Deferred income taxes noncurrent	1,090	1,115
Pension and other post-retirement liabilities	1,322	1,017
Other long-term liabilities	3,208	3,357
Long-term liabilities of discontinued and held for sale businesses	411	429
Total long-term liabilities	23,974	22,537
Contingencies and Commitments (see Notes 11 and 12)		
Cumulative preferred stock of subsidiary	60	60
EQUITY		
THE AES CORPORATION STOCKHOLDERS EQUITY		
Common stock ($0.01 par value, 1,200,000,000 shares authorized; 677,214,493 issued and 667,679,913 outstanding at December 31, 2009 and 673,478,012 issued and 662,786,745 outstanding at December 31, 2008)	7	7
Additional paid-in capital	6,868	6,832
Retained earnings (accumulated deficit)	650	(8)
Accumulated other comprehensive loss	(2,724)	(3,018)
Treasury stock, at cost (9,534,580 and 10,691,267 shares at December 31, 2009 and 2008, respectively)	(126)	(144)
Total The AES Corporation stockholders equity	4,675	3,669
NONCONTROLLING INTERESTS	4,205	3,358
Total equity	8,880	7,027
TOTAL LIABILITIES AND EQUITY	$ 39,535	$ 34,806

See Accompanying Notes to these Consolidated Financial Statements

Table of Contents

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

YEARS ENDED DECEMBER 31, 2009, 2008, AND 2007

	2009	2008	2007
	(in millions, except per share amounts)		
Revenue:			
Regulated	$ 7,816	$ 7,768	$ 6,863
Non-Regulated	6,303	7,590	6,151
Total revenue	14,119	15,358	13,014
Cost of Sales:			
Regulated	(5,705)	(5,564)	(4,746)
Non-Regulated	(4,919)	(6,162)	(4,970)
Total cost of sales	(10,624)	(11,726)	(9,716)
Gross margin	3,495	3,632	3,298
General and administrative expenses	(345)	(371)	(378)
Interest expense	(1,515)	(1,803)	(1,755)
Interest income	348	519	489
Other expense	(111)	(161)	(253)
Other income	466	377	358
Gain on sale of investments	131	909	
(Loss) gain on sale of subsidiary stock		(31)	134
Goodwill impairment	(122)		
Asset impairment expense	(25)	(175)	(408)
Foreign currency transaction gains (losses) on net monetary position	33	(184)	29
Other non-operating expense	(12)	(15)	(57)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES AND EQUITY IN EARNINGS OF AFFILIATES	2,343	2,697	1,457
Income tax expense	(599)	(771)	(676)
Net equity in earnings of affiliates	92	33	76
INCOME FROM CONTINUING OPERATIONS	1,836	1,959	857
Income from operations of discontinued businesses, net of income tax expense of $3, $7 and $32, respectively	69	67	161
Gain (loss) from disposal of discontinued businesses, net of income tax benefit of $, $ and $8, respectively	(150)	6	(661)
NET INCOME	1,755	2,032	357
Noncontrolling interests:			
Less: Income from continuing operations attributable to noncontrolling interests	(1,107)	(770)	(403)
Less: Income (loss) from discontinued operations attributable to noncontrolling interests	10	(28)	(49)
Total net income attributable to noncontrolling interests	(1,097)	(798)	(452)
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ 658	$ 1,234	$ (95)
BASIC EARNINGS (LOSS) PER SHARE:			
Income from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 1.09	$ 1.78	$ 0.68
Discontinued operations attributable to The AES Corporation common stockholders, net of tax	(0.10)	0.06	(0.82)

NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ 0.99	$ 1.84	$ (0.14)
DILUTED EARNINGS (LOSS) PER SHARE:			
Income from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 1.09	$ 1.76	$ 0.67
Discontinued operations attributable to The AES Corporation common stockholders, net of tax	(0.11)	0.06	(0.81)
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ 0.98	$ 1.82	$ (0.14)
AMOUNTS ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:			
Income from continuing operations, net of tax	$ 729	$ 1,189	$ 454
Discontinued operations, net of tax	(71)	45	(549)
Net income (loss)	$ 658	$ 1,234	$ (95)

See Accompanying Notes to these Consolidated Financial Statements

Table of Contents

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED DECEMBER 31, 2009, 2008, AND 2007

	2009	2008 (in millions)	2007
OPERATING ACTIVITIES:			
Net income	$ 1,755	$ 2,032	$ 357
Adjustments to net income:			
Depreciation and amortization	1,049	1,001	942
Loss (gain) from sale of investments and impairment expense	57	(712)	333
Loss (gain) on disposal and impairment write-down discontinued operations	150	(7)	669
Provision for deferred taxes	15	160	210
Contingencies	(122)	52	196
(Gain) loss on the extinguishment of debt	(6)	56	92
Noncontrolling interest of discontinued operations		(4)	(21)
Other	(99)	127	(13)
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable	62	(451)	(306)
Increase in inventory	(34)	(83)	(26)
Decrease (increase) in prepaid expenses and other current assets	149	(61)	362
Increase in other assets	(177)	(467)	(134)
(Decrease) increase in accounts payable and accrued liabilities	(308)	260	(322)
Increase (decrease) in income taxes and other income tax payables, net	88	226	(140)
(Decrease) increase in other liabilities	(366)	32	155
Net cash provided by operating activities	2,213	2,161	2,354
INVESTING ACTIVITIES:			
Capital expenditures	(2,520)	(2,850)	(2,425)
Acquisitions net of cash acquired		(1,135)	(315)
Proceeds from the sale of businesses	2	1,328	1,136
Proceeds from the sale of assets	17	105	16
Sale of short-term investments	4,526	5,150	2,492
Purchase of short-term investments	(4,248)	(5,469)	(2,982)
Decrease (increase) in restricted cash	302	(295)	(28)
Decrease (increase) in debt service reserves and other assets	185	(100)	122
Affiliate advances and equity investments	(155)	(240)	(32)
Loan advances		(173)	
Other investing	(26)	98	46
Net cash used in investing activities	(1,917)	(3,581)	(1,970)
FINANCING ACTIVITIES:			
Borrowings (repayments) under the revolving credit facilities, net	11	298	(85)
Issuance of recourse debt	503	625	2,000
Issuance of non-recourse debt	1,997	2,158	2,297
Repayments of recourse debt	(154)	(1,037)	(1,315)
Repayments of non-recourse debt	(1,008)	(1,260)	(2,251)
Payments for deferred financing costs	(91)	(82)	(97)
Distributions to noncontrolling interests	(846)	(597)	(699)
Contributions from noncontrolling interests	190	410	374
Financed capital expenditures	(18)	(47)	(35)
Purchase of treasury stock		(143)	
Other financing	26	37	55
Net cash provided by financing activities	610	362	244

Effect of exchange rate changes on cash	22	(96)	69
Total increase (decrease) in cash and cash equivalents	928	(1,154)	697
Cash and cash equivalents, beginning	881	2,035	1,338
Cash and cash equivalents, ending	$ 1,809	$ 881	$ 2,035
SUPPLEMENTAL DISCLOSURES:			
Cash payments for interest, net of amounts capitalized	$ 1,395	$ 1,615	$ 1,762
Cash payments for income taxes, net of refunds	$ 484	$ 465	$ 621
SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES:			
Assets acquired in acquisition of subsidiary	$	$ 1,097	$ 434
Non-recourse debt assumed in acquisition of subsidiary	$	$	$ 647
Liabilities extinguished due to sale of assets	$	$	$ 134
Liabilities assumed in acquisition of subsidiary	$	$ 49	$ 37
Assets acquired in noncash asset exchange	$ 111	$ 18	$
Assets disposed of in noncash asset exchange	$	$ 4	$

Table of Contents

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY

YEARS ENDED DECEMBER 31, 2009, 2008, AND 2007

	THE AES CORPORATION STOCKHOLDERS								
	Common Stock		Treasury Stock						
	Shares	Amount	Shares	Amount	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Consolidated Comprehensive Income
					(in millions)				
Balance at January 1, 2007	665.1	$ 7		$	$ 6,659	$ (1,093)	$ (2,594)	$ 2,867	
Net income (loss)						(95)		452	357
Cumulative effect of adoption of uncertain tax position accounting guidance						(53)			
Change in fair value of available-for-sale securities, net of income tax							3		3
Foreign currency translation adjustment, net of income tax							324	319	643
Change in unfunded pensions obligation, net of income tax							8	(11)	(3)
Change in derivative fair value, including a reclassification to earnings, net of income tax							(119)	(15)	(134)
Other comprehensive income									509
Total comprehensive income									$ 866
Capital contributions from noncontrolling interests								290	
Dividends declared to noncontrolling interests								(578)	
Disposition of businesses								(143)	
Issuance of common stock under benefit plans and exercise of stock options and warrants, net of income tax	5.2				85				
Stock compensation					32				
Balance at December 31, 2007	670.3	$ 7		$	$ 6,776	$ (1,241)	$ (2,378)	$ 3,181	
Net income						1,234		798	$ 2,032
Foreign currency translation adjustment, net of income tax							(560)	(492)	(1,052)
Change in unfunded pensions obligation, net of income tax							(49)	(100)	(149)
Change in derivative fair value, including a reclassification to earnings, net of income tax							(31)	(37)	(68)
Other comprehensive income									(1,269)
Total comprehensive income									$ 763
Capital contributions from noncontrolling interests								619	
								(574)	

Dividends declared to noncontrolling interests									
Disposition of businesses								(37)	
Effect of pension measurement date change						(1)			
Acquisition of treasury stock			10.7	(144)					
Issuance of common stock under benefit plans and exercise of stock options and warrants, net of income tax	3.2				30				
Stock compensation					26				
Balance at December 31, 2008	673.5	$ 7	10.7	$ (144)	$ 6,832	$ (8)	$ (3,018)	$ 3,358	
Net income						658		1,097	$ 1,755
Change in fair value of available-for-sale securities, net of income tax							6		6
Foreign currency translation adjustment, net of income tax							271	471	742
Change in unfunded pensions obligation, net of income tax							(23)	(116)	(139)
Change in derivative fair value, including a reclassification to earnings, net of income tax							40	33	73
Other comprehensive income									682
Total comprehensive income									$ 2,437
Capital contributions from noncontrolling interests								195	
Dividends declared to noncontrolling interests								(825)	
Disposition of businesses								(8)	
Issuance of treasury stock			(1.2)	18	(20)				
Issuance of common stock under benefit plans and exercise of stock options and warrants, net of income tax	3.7				18				
Stock compensation					38				
Balance at December 31, 2009	677.2	$ 7	9.5	$ (126)	$ 6,868	$ 650	$ (2,724)	$ 4,205	

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2009, 2008, AND 2007

1. GENERAL AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The AES Corporation is a holding company (the Parent Company) that through its subsidiaries and affiliates, (collectively, AES or the Company) operates a geographically diversified portfolio of electricity generation and distribution businesses.

PRINCIPLES OF CONSOLIDATION The Consolidated Financial Statements of the Company include the accounts of The AES Corporation, its subsidiaries and controlled affiliates, and variable interest entities (VIEs) of which the Company is the primary beneficiary. All intercompany transactions and balances have been eliminated in consolidation.

A VIE is an entity (a) that has a total equity investment at risk that is not sufficient to finance its activities without additional subordinated financial support provided by any parties or (b) where the group of equity holders does not have (i) the ability to make significant decisions about the entity s activities, (ii) the obligation to absorb the entity s expected losses or (iii) the right to receive the entity s expected residual returns or (c) where the voting rights of some equity holders are not proportional to their obligations to absorb expected losses, receive expected residual returns or both, and substantially all of the entity s activities either involve or are conducted on behalf of an investor that has disproportionately few voting rights.

The Company is considered the primary beneficiary of a VIE and thus consolidates the VIE when the Company absorbs a majority of expected losses of the VIE, receives a majority of expected residual returns of the VIE (unless another enterprise absorbs the majority of expected losses), or both. Where it is not clear which variable interest holder is the primary beneficiary the Company performs computations and allocations of expected losses and expected residual returns as necessary to determine the primary beneficiary. The primary beneficiary determination has not historically required significant judgments or assumptions to be made.

The Company determines if it is the primary beneficiary when it becomes involved in the VIE. If the Company is the primary beneficiary, it reconsiders this decision when it sells or otherwise disposes of all or part of our variable interests to unrelated parties or if the VIE issues new variable interests to parties other than the Company or its related parties. Conversely, if the Company is not the primary beneficiary, it reconsiders this decision when it acquires additional variable interests in these entities.

USE OF ESTIMATES The preparation of these consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) requires the Company to make estimates and assumptions that affect reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the consolidated financial statements, as well as the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates. Items subject to such estimates and assumptions include the carrying value and estimated useful lives of long-lived assets; impairment of goodwill and equity method investments; valuation allowances for receivables and deferred tax assets; the recoverability of deferred regulatory assets; the valuation of certain financial instruments; the determination of noncontrolling interest using the hypothetical liquidation at book value (HLBV) method for certain wind generation partnerships; pension liabilities; environmental liabilities; and potential litigation claims and settlements.

DISCONTINUED OPERATIONS AND RECLASSIFICATIONS Certain immaterial prior period amounts have been reclassified within the Consolidated Financial Statements to conform to current year presentation. Additionally, in December 2009, the Company entered into agreements to sell its entire interests in two oil-fired generation plants, Lal Pir and Pak Gen, in Pakistan and a combined gas-fired generation and water

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

desalination facility, Barka, in Oman. In accordance with the accounting standards on the impairment or disposal of long-lived assets, these operations were considered to be held for sale as of December 31, 2009 and the prior period Consolidated Financial Statements in this Form 10-K have been restated to reflect these businesses as discontinued operations, as discussed in Note 21 Discontinued Operations and Held for Sale Businesses.

FAIR VALUE Fair value, as defined in the fair value measurement accounting guidance, is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or exit price. The Company adopted the fair value measurement accounting guidance for financial assets and liabilities on January 1, 2008 and for nonfinancial assets and liabilities measured on a non-recurring basis on January 1, 2009. This guidance was applied prospectively and the adoption did not materially impact the Company s financial condition, results of operations, or cash flows. The Company applies the fair value measurement accounting guidance to determine the fair value of short and long term investments in marketable debt and equity securities, included in the consolidated balance sheet line items Short-term investments and Other assets (noncurrent) , derivative assets, included in Other current assets and Other assets (noncurrent) and derivative liabilities, included in Accrued and other liabilities (current) and Other long-term liabilities .

The fair value measurement accounting guidance requires that the Company make assumptions market participants would use in pricing an asset or liability based on the best information available. Reporting entities are required to consider factors that were not previously measured when determining the fair value of financial instruments. These factors include nonperformance risk (the risk that the obligation will not be fulfilled) and credit risk, of the reporting entity (for liabilities) and of the counterparty (for assets). The fair value measurement guidance prohibits inclusion of transaction costs and any adjustments for blockage factors in determining the instruments fair value. The principal or most advantageous market should be considered from the perspective of the reporting entity.

Fair value, where available, is based on observable quoted market prices. Where observable prices or inputs are not available, several valuation models and techniques are applied. These models and techniques attempt to maximize the use of observable inputs and minimize the use of unobservable inputs. The process involves varying levels of management judgment, the degree of which is dependent on the price transparency of the instruments or market and the instruments complexity.

To increase consistency and enhance disclosure of the fair value of financial instruments, the fair value measurement accounting guidance creates a fair value hierarchy to prioritize the inputs used to measure fair value into three categories. A financial instrument s level within the fair value hierarchy is based on the lowest level of input significant to the fair value measurement, where Level 1 is the highest and Level 3 is the lowest. The three levels are defined as follows:

Level 1 unadjusted quoted prices in active markets accessible by the reporting entity for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The fair value of most investments in marketable securities is based on quoted market prices.

Level 2 pricing inputs other than quoted market prices included in Level 1 that are based on observable market data, that are directly or indirectly observable for substantially the full term of the asset or liability. These include quoted market prices for similar assets or liabilities, quoted market prices for identical or similar assets in

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

markets that are not active, adjusted quoted market prices, inputs from observable data such as interest rate and yield curves, volatilities or default rates observable at commonly quoted intervals or inputs derived from observable market data by correlation or other means. The fair value of most over-the-counter derivatives derived from internal valuation models using market inputs and some investments in marketable securities qualify as level 2.

Level 3 pricing inputs that are unobservable, or less observable, from objective sources. Unobservable inputs should only be used to the extent observable inputs are not available. These inputs maintain the concept of an exit price from the perspective of a market participant and should reflect assumptions of other market participants. An entity should consider all market participant assumptions that are available without unreasonable cost and effort. These are given the lowest priority and are generally used in internally developed methodologies to generate management s best estimate of the fair value when no observable market data is available. The fair value of the Company s reporting units determined using a discounted cash flows valuation model for the annual goodwill impairment assessment qualifies as level 3.

CASH AND CASH EQUIVALENTS The Company considers unrestricted cash on hand, deposits in banks, certificates of deposit and short-term marketable securities, with an original or remaining maturity at the date of acquisition of three months or less, to be cash and cash equivalents. The carrying amount of such balances approximate fair value.

RESTRICTED CASH Restricted cash includes cash and cash equivalents which are restricted as to withdrawal or usage. The nature of restrictions includes restrictions imposed by the financing agreements such as security deposits kept as collateral, debt service reserves, maintenance reserves and others, as well as restrictions imposed by long-term power purchase agreements (PPA).

INVESTMENTS IN MARKETABLE SECURITIES Short-term investments in marketable debt and equity securities consist of securities with original or remaining maturities in excess of three months but less than one year. The Company s marketable investments are primarily certificates of deposit, government debt securities and money market funds.

Marketable debt securities that the Company has both the positive intent and ability to hold to maturity are classified as held-to-maturity and are carried at amortized cost. Other marketable securities that the Company does not intend to hold to maturity are classified as available-for-sale or trading and are carried at fair value. Available-for-sale investments are marked-to-market at the end of each reporting period, with unrealized holding gains or losses, which represent changes in the market value of the investment, reflected in accumulated other comprehensive income (AOCI), a separate component of stockholders equity.

The Company adopted the new accounting guidance related to investments in debt and equity securities that became effective during the year. The new guidance improved the presentation and disclosure of other-than-temporary impairment on debt and equity securities in the financial statements and changed the accounting requirements related to the recognition of other-than-temporary impairment of debt securities. The new guidance identifies two components of an other-than-temporary impairment: 1) the amount representing the credit loss, which is recognized as other non-operating expense in the Consolidated Statements of Operations; and 2) the amount related to other factors, which is recognized in AOCI unless there is a plan to sell the security, in which case it would be recognized in earnings. The amount recognized in AOCI for held-to-maturity debt securities is then amortized over the remaining life of the security. The new guidance was effective for new and existing securities held by an entity as of the beginning of the period adopted and required a cumulative adjustment to the opening balance of retained earnings in the period of adoption with a corresponding adjustment to AOCI.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The adoption of the new guidance did not have a material impact on the Company s financial condition, results of operations or cash flows. The Company has incorporated the additional disclosure requirements in this Form 10-K.

Investments classified as trading are marked-to-market on a periodic basis through the Consolidated Statements of Operations. Interest and dividends on investments are reported in interest income and other income, respectively. Gains and losses on sales of investments are determined using the specific identification method.

See Note 6 Fair Value of Financial Instruments and the Company s Fair Value policy for additional discussion regarding the determination of the fair value of the Company s investments in marketable debt and equity securities.

ALLOWANCE FOR DOUBTFUL ACCOUNTS The Company maintains an allowance for doubtful accounts for estimated uncollectible accounts receivable. The allowance is based on the Company s assessment of known delinquent accounts, historical experience and other currently available evidence of the collectibility and the aging of accounts receivable.

INVENTORY Inventory primarily consists of coal, fuel oil and other raw materials used to generate power and spare parts and supplies used to maintain power generation and distribution facilities. Inventory is carried at cost, which is the sum of the purchase price and incidental expenditures and charges incurred to bring the inventory to its existing condition or location. Cost is determined under the first-in, first-out (FIFO) or average cost method. Generally, cost is reduced to market value if the market value of inventory has declined and it is probable that the utility of inventory, in its disposal in the ordinary course of business, will not be recovered through revenue earned from the generation of power.

PROPERTY, PLANT AND EQUIPMENT Property, plant and equipment are stated at cost net of accumulated depreciation. The cost of renewals and betterments that extend the useful life of property, plant and equipment are capitalized.

Construction progress payments, engineering costs, insurance costs, salaries, interest and other costs directly relating to construction in progress are capitalized during the construction period, provided the completion of the project is deemed probable, or expensed at the time the Company determines that development of a particular project is no longer probable. The continued capitalization of such costs is subject to ongoing risks related to successful completion, including those related to government approvals, site identification, financing, construction, permitting and contract compliance. Construction in progress balances are transferred to electric generation and distribution assets when each asset is ready for its intended use. Government subsidies are recorded as a reduction to property, plant and equipment and reflected in cash flows from investing activities.

Depreciation, after consideration of salvage value and asset retirement obligations, is computed primarily using the straight-line method over the estimated useful lives of the assets, which are determined on a composite or component basis. Maintenance and repairs are charged to expense as incurred. Capital spare parts, including rotable spare parts, are included in electric generation and distribution assets. If the part is considered a component, it is depreciated over its useful life after the part is placed in service. If the part is deemed part of a composite asset, the part is depreciated over the composite useful life even when being held as a spare part.

DEFERRED FINANCING COSTS Financing costs are deferred and amortized over the related financing period using the effective interest method or the straight-line method when it does not differ materially from the effective interest method. Make-whole payments in connection with early debt retirements are classified as cash flows used in investing activities.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

EQUITY METHOD INVESTMENTS Investments in entities over which the Company has the ability to exercise significant influence, but not control, are accounted for using the equity method of accounting and reported in Investments in and Advances to Affiliates on the Consolidated Balance Sheets. In accordance with the accounting guidance for equity method investments, the Company periodically assesses the recoverability of its equity method investments. If an identified event or change in circumstances requires an impairment evaluation, management assesses the fair value based on valuation methodologies, including discounted cash flows, estimates of sale proceeds and external appraisals, as appropriate. The difference between the carrying value of the equity method investment and its estimated fair value is recognized as impairment when the loss in value is deemed other-than-temporary and included in other non-operating expense on the Consolidated Statements of Operations.

In accordance with the accounting standards for equity method investments, the Company discontinues the application of the equity method when an investment is reduced to zero and the Company is not otherwise committed to provide further financial support to the investee. The Company resumes the application of the equity method if the investee subsequently reports net income to the extent that the Company s share of such net income equals the share of net losses not recognized during the period in which the equity method of accounting was suspended.

GOODWILL AND OTHER INTANGIBLES In accordance with the accounting guidance on goodwill and other intangible assets, the Company recognizes goodwill as an asset representing the future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognized. The Company evaluates goodwill and indefinite-lived intangible assets for impairment on an annual basis and whenever events or changes in circumstances necessitate an evaluation for impairment. The Company s annual impairment testing date is October 1st.

Goodwill:

The Company evaluates goodwill impairment at the reporting unit level, which is an operating segment, as defined in the segment reporting accounting guidance, or one level below an operating segment, a component. In determining its reporting units, the Company starts with its segment reporting structure. Operating segments are identified and then analyzed to identify components (usually businesses) which make up these operating segments. Assets and liabilities are allocated to a reporting unit if assets will be employed by or a liability relates to the operations of a reporting unit or would be considered in determining its fair value. Two or more components are combined into a single reporting unit if they share the economic similarity criteria prescribed by the accounting guidance. The goodwill impairment evaluation is performed in two steps. In step 1, the carrying value of a reporting unit is compared to its fair value and if the fair value exceeds the carrying value, step 2 is unnecessary. When the carrying value of a reporting unit exceeds its fair value, step 2 is performed to determine the implied fair value of goodwill. To estimate the implied fair value of goodwill, the fair values of individual assets and liabilities of the reporting unit are determined as if it were a business combination. An impairment loss is recognized if the carrying amount of goodwill exceeds its implied fair value.

Most of the Company s reporting units are not publicly traded and the Company has estimated the fair value of its reporting units using internal valuation models based on discounted cash flow principles. Effective January 1, 2009, the Company adopted the fair value measurement guidance for nonfinancial assets and liabilities measured at fair value on a nonrecurring basis. The adoption resulted in the introduction of several modifications to the Company s internal valuation model to align it with the new accounting guidance. Most notably, the new accounting guidance requires making assumptions that a market participant would make in a hypothetical sale transaction at the testing date. The fair value of a reporting unit was estimated using internal budgets and forecasts, adjusted for any market participants assumptions and discounted at the rate of return

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

required by a market participant. When estimating the fair value of its reporting units, the Company considers both market and income-based approaches to determine a range of fair value, but typically concludes that the value derived using an income-based approach is more representative of fair value due to the lack of direct market comparables. The Company does use market data to corroborate and determine the reasonableness of the fair value derived from the income-based discounted cash flow analysis. The adoption of this guidance did not have a material impact on the Company s financial condition or results of operations.

Intangible Assets:

Finite-lived intangible assets are amortized over their useful lives which range from 2 - 95 years. The Company accounts for emission allowances as intangible assets and charges them to expense when sold or used; granted allowances are valued at zero. The Company s indefinite-lived intangible assets, which include items such as land use rights, are tested for impairment on an annual basis in accordance with applicable accounting guidance for intangible assets.

INCOME TAXES Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax bases. The Company establishes a valuation allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. As discussed in Note 20 Income Taxes, in June 2006, the Financial Accounting Standards Board (FASB) issued new accounting guidance related to uncertainty in income taxes, which applied to our financial statements beginning January 1, 2007. This new accounting guidance applies to all tax positions accounted for in accordance with the accounting standards for income taxes and requires the Company s tax positions to be evaluated under a more-likely-than-not recognition threshold and measurement analysis before they can be recognized for financial statement reporting. The Company adopted this new accounting guidance on January 1, 2007 and recognized a cumulative effect of $53 million as an adjustment to beginning retained earnings.

Uncertain tax positions have been classified as noncurrent income tax liabilities unless expected to be paid within one year. The Company s policy for interest and penalties related to income tax exposures is to recognize interest and penalties as a component of the provision for income taxes in the Consolidated Statements of Operations.

PENSION AND OTHER POSTRETIREMENT PLANS In accordance with the accounting guidance on defined benefit pension and other postretirement plans, the Company recognizes in its Consolidated Balance Sheets an asset or liability reflecting the funded status of pension and other postretirement plans with current year changes in the funded status recognized in AOCI. All plan assets are recorded at fair value. AES follows the measurement date provisions of the accounting guidance, which require a year-end measurement date of plan assets and obligations for all defined benefit plans. The adoption of year-end measurement date requirements at December 31, 2008 resulted in a cumulative adjustment to retained earnings of $1 million.

NONCONTROLLING INTERESTS Effective January 1, 2009, the Company adopted the new accounting guidance for noncontrolling interests, which changed the accounting for and the reporting of minority interest, now referred to as noncontrolling interests, in the Company s consolidated financial statements. This resulted in the reclassification of minority interest amounts, previously classified as a separate component of equity, to Noncontrolling Interests , a component within permanent equity, in the accompanying Consolidated Balance Sheets and Statements of Changes in Equity. Additionally, net income and comprehensive income attributable to noncontrolling interests are reflected separately from consolidated net income and comprehensive

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

income in the accompanying Consolidated Statements of Operations and Statements of Changes in Equity. The new accounting guidance also requires that any change in ownership of a subsidiary while the controlling financial interest is retained should be accounted for as an equity transaction between the controlling and noncontrolling interests. Gains or losses from such transactions are no longer recognized in net income and the carrying values of the subsidiary s assets (including goodwill) and liabilities are not adjusted. Previous SEC guidance provided an option in certain circumstances for a parent to recognize a gain or loss on the sale of stock by a subsidiary or account for the sale as an equity transaction. In certain transactions, AES had previously elected the option to recognize a gain or loss. Under the revised guidance, this option is no longer available.

Losses continue to be attributed to the noncontrolling interests, even when the noncontrolling interests basis has been reduced to zero. Previously, losses that otherwise would have been attributed to the noncontrolling interests were allocated to the controlling interest after the associated noncontrolling interests basis was reduced to zero. The Company had no material losses that it did not allocate to noncontrolling interests prior to the adoption of the new noncontrolling interests accounting guidance and the adoption did not have a material impact on the Company s financial position or results of operations.

Although in general, the noncontrolling ownership interest in earnings is calculated based on ownership percentage, certain of our wind businesses use the HLBV method in consolidation. HLBV uses a balance sheet approach, which measures equity in income or loss by calculating the change in the amount of net worth partners are legally able to claim based on a liquidation of the entity at the beginning of a reporting period compared to the end of that period. This method is used in AES Wind Generation ventures which contain agreements designating different allocations of value among investors, where the allocations change in form or percentage over the life of the venture. In the fourth quarter of 2009, net income attributable to noncontrolling interests and income tax expense increased $44 million and decreased $16 million, respectively. Accordingly, net income and income from continuing operations increased $16 million and net income attributable to The AES Corporation decreased $28 million, or $0.04 per share, for the year ended December 31, 2009, as a result of a charge related to the potential future taxes that could be deemed to be due in the calculation of the hypothetical liquidation value of certain of our wind equity partnerships.

LONG-LIVED ASSETS In accordance with the accounting standards for the impairment or disposal of long-lived assets, the Company evaluates the impairment of long-lived assets based on the projection of undiscounted cash flows when circumstances indicate that the carrying amount of such assets may not be recoverable or the assets meet the held for sale criteria under the relevant accounting standards. These events or circumstances may include the relative pricing of wholesale electricity by region, anticipated demand and cost of fuel. If the carrying amount is not recoverable, an impairment charge is recognized for the amount by which the carrying value of the long-lived asset exceeds its fair value. For regulated assets, an impairment charge could be offset by the establishment of a regulatory asset, if recovery through approved rates was probable. For non-regulated assets, an impairment charge is recognized as a charge against earnings.

In connection with the periodic evaluation of long-lived assets in accordance with the accounting standards on impairment or disposal of long-lived assets, the fair value of the asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. In cases of impairment described in Note 19 Asset Impairment Expense, we made our best estimate of fair value using valuation methods based on the most current information available at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and management s analysis of the benefits of the transaction.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

ASSET RETIREMENT OBLIGATIONS In accordance with the accounting standards for asset retirement obligations, the Company records the fair value of the liability for a legal obligation to retire an asset in the period in which the obligation is incurred. When a new liability is recognized, the Company will capitalize the costs of the liability by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the obligation, the Company eliminates the liability and, based on the actual cost to retire, may incur a gain or loss.

GUARANTOR ACCOUNTING In accordance with the accounting standards on guarantees, at the inception of a guarantee, the Company records the fair value of a guarantee as a liability, with the offset dependent on the circumstances under which the guarantee was issued.

FOREIGN CURRENCY TRANSLATION A business functional currency is the currency of the primary economic environment in which the business operates and is generally the currency in which the business generates and expends cash. Subsidiaries and affiliates whose functional currency is other than the U.S. Dollar translate their assets and liabilities into U.S. Dollars at the current exchange rates in effect at the end of the fiscal period. The revenue and expense accounts of such subsidiaries and affiliates are translated into U.S. Dollars at the average exchange rates that prevailed during the period. Translation adjustments are included in AOCI. Gains and losses on intercompany foreign currency transactions which are long-term in nature, which the Company does not intend to settle in the foreseeable future, are also recognized in AOCI. Gains and losses that arise from exchange rate fluctuations on transactions denominated in a currency other than the functional currency are included in determining net income.

REVENUE RECOGNITION Revenue from the Utilities business is classified as regulated on the Consolidated Statements of Operations. Revenue from the sale of energy is recognized in the period during which the sale occurs. The calculation of revenue earned but not yet billed is based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month. Differences between actual and estimated unbilled revenue are usually immaterial. Revenue from the Generation business is classified as non-regulated and is recognized based upon output delivered and capacity provided, at rates as specified under contract terms or prevailing market rates. The Company has businesses where it makes sales and purchases of power to and from Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). In those instances, the Company accounts for these transactions on a net hourly basis because the transactions are settled on a net hourly basis. Revenue is recorded net of any taxes assessed on and collected from customers, which are remitted to the governmental authorities.

SHARE-BASED COMPENSATION The Company grants share-based compensation in the form of stock options and restricted stock units. The Company accounts for stock-based compensation plans under the accounting guidance on stock-based compensation, which requires entities to recognize compensation costs relating to share-based payments in their financial statements. That cost is measured on the grant date based on the fair value of equity or liability instruments issued and is expensed on a straight-line basis over the requisite service period, net of estimated forfeitures. Currently, the Company uses a Black-Scholes option pricing model to estimate the fair value of stock options granted to its employees.

GENERAL AND ADMINISTRATIVE EXPENSES General and administrative expenses include corporate and other expenses related to corporate staff functions and initiatives, primarily executive management, finance, legal, human resources and information systems, which are not directly allocable to our business segments. Additionally, all costs associated with business development efforts are classified as general and administrative.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

REGULATORY ASSETS AND LIABILITIES The Company accounts for certain of its regulated operations in accordance with the accounting standards on regulated operations. As a result, AES records assets and liabilities that result from the regulated ratemaking process that are not recognized under GAAP for non-regulated entities. Regulatory assets generally represent incurred costs that have been deferred due to the probability of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities and the status of any pending or potential deregulation legislation. If future recovery of costs previously deferred ceases to be probable, the asset write-offs are recognized in continuing operations.

DERIVATIVES AND HEDGING ACTIVITIES Derivatives primarily consist of interest rate swaps, cross currency swaps, foreign currency instruments and commodity and embedded derivatives. The Company enters into various derivative transactions in order to hedge its exposure to certain market risks. AES primarily uses derivative instruments to manage its interest rate, foreign currency and commodity exposures. The Company does not enter into derivative transactions for trading purposes.

Under the accounting standards for derivatives and hedging, the Company recognizes all contracts that meet the definition of a derivative, except those designated as normal purchase or normal sale at inception, as either assets or liabilities in the Consolidated Balance Sheets and measures those instruments at fair value. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met. Gains and losses related to derivative instruments that qualify as hedges are recognized in the same category as generated by the underlying asset or liability. Gains or losses on derivatives that do not qualify for hedge accounting are recognized as interest expense for interest rate and cross currency derivatives, foreign currency gains or losses on foreign currency derivatives, and non-regulated revenue or non-regulated cost of sales for commodity derivatives.

The accounting standards for derivatives and hedging enable companies to designate qualifying derivatives as hedging instruments based on the exposure being hedged. These hedge designations include fair value hedges and cash flow hedges. Changes in the fair value of a derivative that is highly effective, designated and qualifies as a fair value hedge are recognized in earnings as offsets to the changes in fair value of the exposure being hedged. The Company has no fair value hedges at this time. Changes in the fair value of a derivative that is highly effective, designated and qualifies as a cash flow hedge are deferred in AOCI and are recognized into earnings as the hedged transactions affect earnings. Any ineffectiveness is recognized in earnings immediately. The ineffective portion is recognized as interest expense for interest rate and cross currency hedges, foreign currency gains or losses for foreign currency hedges, and non-regulated revenue or non-regulated cost of sales for commodity hedges. For all hedge contracts, the Company maintains formal documentation of the hedge and effectiveness testing in accordance with the accounting standards for derivatives and hedging. If AES determines that the derivative is not highly effective as a hedge, hedge accounting will be discontinued prospectively.

For cash flow hedges of forecasted transactions, AES estimates the future cash flows of the forecasted transactions and evaluates the probability of the occurrence and timing of such transactions. Changes in conditions or the occurrence of unforeseen events could require discontinuance of hedge accounting or could affect the timing of the reclassification of gains or losses on cash flow hedges from AOCI into earnings.

The Company has elected not to offset net derivative positions in the financial statements. Accordingly, the Company does not offset such derivative positions against the fair value of amounts (or amounts that approximate fair value) recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

See Note 6 Fair Value and the Company s fair value policy for additional discussion regarding the determination of the fair value of the Company s derivative assets and liabilities.

Accounting Pronouncements Issued But Not Yet Effective

The following accounting standards have been issued, but as of December 31, 2009 are not yet effective for and have not been adopted by AES.

ASU No. 2009-17, Consolidations, Improvements to Financial Reporting by Enterprises involved with Variable Interest Entities (ASU No. 2009-17) (former FAS No. 167, Amendments to FASB Interpretation No. 46(R))

In June 2009, the Financial Accounting Standards Board (FASB) issued an amendment to the accounting and disclosure requirements for the consolidation of VIEs. The amendment requires an entity to qualitatively, rather than quantitatively, assess the determination of the primary beneficiary of a VIE. This determination should be based on whether the entity has the power to direct the activities that most significantly impact the economic performance of the VIE and the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE. Other key changes include: the requirement for an ongoing reconsideration of the primary beneficiary, the criteria for determining whether service provider or decision maker contracts are variable interests, the consideration of kick-out and removal rights in determining whether an entity is a VIE, the types of events that trigger the reassessment of whether an entity is a VIE and the expansion of the disclosures previously required. The impact of ASU No. 2009-17 will require the Company to consolidate the assets, liabilities and operating results of certain VIEs, including certain entities currently accounted for under the equity method of accounting that AES does not currently consolidate; see further discussion below. It may also require the Company to deconsolidate certain VIEs that are currently consolidated. The impact of the adoption may be applied retrospectively with a cumulative-effect adjustment to retained earnings as of the beginning of the first year restated, or through a cumulative-effect adjustment on the date of adoption. The new accounting guidance for VIEs is effective for fiscal years beginning after November 15, 2009, or January 1, 2010 for AES. Early adoption is prohibited.

Based on its review to date, the Company has determined that an entity that had not been previously consolidated will be required to be consolidated upon the adoption of the new standard. Cartagena, the Company s generation business in Spain, is currently accounted for under the equity method of accounting and is expected to be consolidated upon the adoption of the new VIE accounting guidance. Total assets and revenue for Cartagena as of and for the year ended December 31, 2009 were $929 million and $147 million, respectively. The Company is still in the process of quantifying the expected impact of the cumulative adjustment to be recorded upon adoption of the new VIE guidance. AES is in the process of completing its review of the potential impact from the adoption of this guidance and may identify additional entities to consolidate or deconsolidate upon adoption in the first quarter of 2010.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

2. INVENTORY

As of December 31, 2009, 84% of the inventory was determined using average cost, 15% was determined using the FIFO method and the remaining were valued using the specific identification method. The following table summarizes our inventory balances as of December 31, 2009 and 2008:

	December 31,	
	2009	2008
	(in millions)	
Coal, fuel oil and other raw materials	$ 293	$ 306
Spare parts and supplies	276	241
Total	$ 569	$ 547

3. PROPERTY, PLANT & EQUIPMENT

The following table summarizes the components of the electric generation and distribution assets and other property, plant and equipment with their estimated useful lives:

	Estimated Useful Life	December 31,	
		2009	2008
		(in millions)	
Electric generation and distribution facilities	3 - 50 yrs.	$ 24,116	$ 21,353
Other buildings	3 - 50 yrs.	1,926	1,652
Furniture, fixtures and equipment	3 - 30 yrs.	687	528
Other	2 - 50 yrs.	733	469
Total electric generation and distribution assets and other		27,462	24,002
Accumulated depreciation		(8,920)	(7,385)
Net electric generation and distribution assets and other[(1)]		$ 18,542	$ 16,617

(1) Net electric generation and distribution assets and other related to Lal Pir, Pak Gen and Barka of $346 million and $522 million as of December 31, 2009 and 2008, respectively, are excluded from the table above and are included in the noncurrent assets of held for sale and discontinued businesses.

The following table summarizes interest capitalized during development and construction on qualifying assets for the years ended December 31, 2009, 2008 and 2007:

	December 31, 2009	2008	2007
		(in millions)	
Interest capitalized during development and construction	$ 187	$ 176	$ 86

Recoveries of liquidated damages from construction delays and government subsidies are reflected as a reduction in the related projects construction costs. Approximately $13 billion of property, plant and equipment, net of accumulated depreciation, was mortgaged, pledged or subject to liens as of December 31, 2009.

Depreciation expense, including the amortization of assets recorded under capital leases, was $1,005 million, $953 million and $880 million for the years ended December 31, 2009, 2008 and 2007, respectively.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

Net electric generation and distribution assets and other include unamortized internal use software costs of $182 million and $104 million as of December 31, 2009 and 2008, respectively. Amortization expense associated with software costs was $48 million, $41 million and $20 million for the years ended December 31, 2009, 2008 and 2007.

The following table summarizes regulated and non-regulated generation and distribution facilities property, plant and equipment and accumulated depreciation as of December 31, 2009 and 2008:

	December 31,	
	2009	2008
	(in millions)	
Regulated assets	$ 11,744	$ 9,760
Regulated accumulated depreciation	(4,830)	(3,902)
Regulated generation, distribution assets, and other, net	6,914	5,858
Non-regulated assets	15,718	14,242
Non-regulated accumulated depreciation	(4,090)	(3,483)
Non-regulated generation, distribution assets, and other, net	11,628	10,759
Total generation and distribution assets, and other, net	$ 18,542	$ 16,617

The following table summarizes the amounts recognized, which were related to asset retirement obligations, for the years ended December 31, 2009 and 2008:

	2009	2008
	(in millions)	
Balance at January 1	$ 70	$ 64
Additional liabilities incurred	17	5
Liabilities settled	(1)	(1)
Accretion expense	5	5
Change in estimated cash flows	10	(2)
Translation adjustments		(1)
Balance at December 31	$ 101	$ 70

The Company s retirement obligations covered by the relevant guidance primarily include active ash landfills, water treatment basins and the removal or dismantlement of certain plant and equipment. The fair value of legally restricted assets for purposes of settling asset retirement obligations was $87 million as of December 31, 2009 and less than $1 million as of December 31, 2008.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

4. INVESTMENTS IN MARKETABLE SECURITIES

The following table sets forth the Company s investments in marketable debt and equity securities classified as trading and available-for-sale as of December 31, 2009 and 2008 by type of investment and by level within the fair value hierarchy. The security types are determined based on the nature and risk of the security and are consistent with how the Company manages, monitors and measures its securities. These securities have been classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the determination of the fair value of the securities and their placement within the fair value hierarchy levels.

	December 31, 2009				2008
	Level 1	Level 2	Level 3	Total	Total
	(in millions)				
AVAILABLE-FOR-SALE:[1]					
Debt securities:					
Unsecured debentures[2]	$	$ 667	$	$ 667	$ 674
Certificates of deposit[2]		652		652	493
Government debt securities		152		152	32
Other debt securities			42	42	42
Subtotal		1,471	42	1,513	1,241
Equity securities:					
Mutual funds	117			117	
Common stock[3]	16			16	1
Money market funds		30		30	21
Subtotal	133	30		163	22
Total available-for-sale	$ 133	$ 1,501	$ 42	$ 1,676	$ 1,263
TRADING:					
Equity securities:					
Mutual funds	7			7	
Total trading	7			7	
TOTAL	$ 140	$ 1,501	$ 42	$ 1,683	$ 1,263
Held-to-maturity securities[4]				8	150
Total marketable securities				$ 1,691	$ 1,413

(1) Amortized cost approximated fair value at December 31, 2009 and 2008, with the exception of the common stock discussed below.

(2) Unsecured debentures are instruments similar to certificates of deposit that are held primarily by our subsidiaries in Brazil. The unsecured debentures and certificates of deposit included here do not qualify as cash equivalents and meet the definition of a security under the relevant guidance and are therefore classified as available-for-sale securities.

(3) During the year ended December 31, 2009, an investment of the Company with a cost basis of $5 million, previously accounted for under the cost method, underwent an initial public offering (IPO). Subsequent to the IPO, the Company s investment in common stock became marketable. Beginning in the third quarter,

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

the common stock was accounted for as available-for-sale and was accordingly adjusted to fair value at each subsequent reporting date. As a result, an unrealized gain of $11 million was recognized in other comprehensive income.

(4) Held-to-maturity securities are not measured at fair value on a recurring basis.

During the second quarter of 2009, three of the Company s generation businesses in the Dominican Republic exchanged $110 million of accounts receivable due from the government-owned distribution companies in the Dominican Republic for sovereign bonds of the same amount. The bonds, which were classified as available-for-sale securities, were adjusted to fair value when acquired. During the second and third quarter of 2009, the Company used a portion of the bonds with a carrying value of $31 million to settle third-party liabilities and sold the remaining bonds. As of December 31, 2009, all of the sovereign bonds had been sold or transferred.

As of December 31, 2009, all available-for-sale debt securities had stated maturities within one year, with the exception of $42 million of auction rate securities and variable rate demand notes held by IPL, a subsidiary of the Company in Indiana. These securities, classified as other debt securities in the table above, had stated maturities of greater than ten years as of December 31, 2009.

The following table summarizes the pre-tax gains and losses related to available-for-sale and trading securities for the years ended December 31, 2009, 2008 and 2007. There were no realized losses on the sale of available-for-sale securities or gains included in earnings that relate to trading securities held at the reporting date. Gains and losses on the sale of investments are determined using the specific identification method.

	December 31,		
	2009	2008 (in millions)	2007
Gains (losses) included in other comprehensive income	$ 10	$ (2)	$ 3
Gains reclassified out of other comprehensive income into earnings	$ 2	$	$
Proceeds from sales	$ 4,313	$ 5,006	$ 2,345
Gross realized gains on sales	$ 3	$	$

There was no other-than-temporary impairment of marketable securities recognized in the years ended December 31, 2009 and 2008. The Company recognized other-than-temporary impairment charges on a marketable security of $52 million for the year ended December 31, 2007 related to the Company s investment in AgCert International (AgCert). The Company acquired a 9.9% ownership interest in AgCert for $52 million in May 2006 and, in accordance with the accounting standards for investments, classified these securities as available-for-sale . At that time, our investment in the stock, which was traded on the London Stock Exchange, was classified as a long-term available-for-sale investment. There was a material decline in the market value of these securities, based on a continual decline in the traded market price during the year ended December 31, 2007, and the Company recognized an other-than-temporary impairment charge of $52 million. The Company began consolidating AgCert in January 2008 when it became the primary beneficiary.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following table sets forth the Company s investments in marketable debt securities classified as held-to-maturity as of December 31, 2009 and 2008:

	December 31, 2009	December 31, 2008
	(in millions)	
Government debt securities	$ 3	$ 93
Certificates of deposit	4	45
Other	1	12
Total[(1)]	$ 8	$ 150

(1) At December 31, 2009 and 2008, $2 million and $14 million, respectively, of investments classified as held-to-maturity were restricted or pledged as collateral for certain debt or other arrangements.

The amortized cost approximated fair value of the held-to-maturity investments at December 31, 2009 and 2008. As of December 31, 2009, all held-to-maturity debt securities, including restricted investments, had stated maturities within one year.

5. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Risk Management Objectives

The Company is exposed to market risks associated with its enterprise-wide business activities, namely the purchase and sale of fuels and electricity as well as foreign currency risk and interest rate risk. In order to manage the market risks associated with these business activities, we enter into contracts that incorporate derivatives and financial instruments, including forwards, futures, options, swaps or combinations thereof as appropriate. The Company will apply hedge accounting for all contracts so long as they are eligible under the accounting standards for derivatives and hedging. Derivative transactions are not entered into for trading purposes.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

Interest Rate Risk

AES and its subsidiaries utilize variable rate debt financing for construction projects and operations, resulting in an exposure to interest rate risk. Interest rate swap, cap and floor agreements are entered into to manage interest rate risk by effectively fixing or limiting the interest rate exposure on the underlying financing. These interest rate contracts range in maturity through 2027, and are typically designated as cash flow hedges. The following table sets forth, by type of interest rate index, the Company s current and maximum outstanding notional under its interest rate derivative instruments, the weighted average remaining term and the percentage of variable-rate debt hedged that is based on that index as of December 31, 2009 regardless of whether the derivative instruments are in qualifying cash flow hedging relationships:

	December 31, 2009					
	Current		Maximum(1)			
Interest Rate Derivatives	Derivative Notional	Derivative Notional Translated to USD	Derivative Notional	Derivative Notional Translated to USD	Weighted Average Remaining Term(1)	% of Debt Currently Hedged by Index(2)
	(in millions)				(in years)	
Libor (U.S. Dollar)	2,853	$ 2,853	3,245	$ 3,245	10	73%
Euribor (Euro)	804	1,151	820	1,175	12	78%
Libor (British Pound Sterling)	49	79	49	79	10	66%
Treasury Bills (U.S. Dollar)	70	70	70	70	<1	100%
City of Petersburg, IN Pollution Control Refunding Revenue Bonds Adjustable Rate (U.S. Dollar)	40	40	40	40	13	100%
Bubor (Hungarian Forint)	1,841	10	1,841	10	<1	70%

(1) The Company s interest rate derivative instruments primarily include accreting and amortizing notionals. The maximum derivative notional represents the largest notional at any point between December 31, 2009 and the maturity of the derivative instrument, which includes forward starting derivative instruments. The weighted average remaining term represents the remaining tenor of our interest rate derivatives weighted by the corresponding maximum notional in USD.

(2) Excludes variable-rate debt tied to other indices where the Company has no interest rate derivatives.

Cross currency swaps are utilized in certain instances to manage the risk related to fluctuations in both interest rates and certain foreign currencies. These cross currency contracts range in maturity through 2028. The following table sets forth, by type of foreign currency denomination, the Company s outstanding notional of its cross currency derivative instruments as of December 31, 2009 which are all in qualifying cash flow hedge relationships. These swaps are amortizing and therefore the notional amount represents the maximum outstanding notional as of December 31, 2009:

	December 31, 2009			
Cross Currency Swaps	Notional	Notional Translated to USD	Weighted Average Remaining Term(1)	% of Debt Currently Hedged by Index(2)
	(in millions)		(in years)	
Chilean Unidad de Fomento (CLF)	6	$ 231	16	82%
Euro (EUR)	2	3	<1	<1%

(1) Represent the remaining tenor of our cross currency swaps weighted by the corresponding notional in USD.
(2) Represents the proportion of foreign currency denominated debt hedged by the same foreign currency denominated notional of the cross currency swap.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

Foreign Currency Risk

We are exposed to foreign currency risk as a result of our investments in foreign subsidiaries and affiliates. AES operates businesses in many foreign environments and such operations in foreign countries may be impacted by significant fluctuations in foreign currency exchange rates. Foreign currency forwards, swaps and options are utilized, where possible, to manage the risk related to fluctuations in certain foreign currencies. These foreign currency contracts range in maturity through 2011. The following tables set forth, by type of foreign currency denomination, the Company s outstanding notional over the remaining terms of its foreign currency derivative instruments as of December 31, 2009 regardless of whether the derivative instruments are in qualifying hedging relationships:

	December 31, 2009			
Foreign Currency Options	**Notional**	**USD Notional[(1)]**	**Probability Adjusted Notional[(2)]**	**Weighted Average Remaining Term[(3)]**
	(in millions)			**(in years)**
Brazilian Real (BRL)	113	$ 64	$ 30	<1

(1) Represent contractual notionals at inception of trade.
(2) Represents the gross notional amounts times the probability of exercising the option, which is based on the relationship of changes in the option value with respect to changes in the price of the underlying currency.
(3) Represents the remaining tenor of our foreign currency options weighted by the corresponding notional in USD.

	December 31, 2009		
Foreign Currency Forwards	**Notional**	**Notional Translated to USD**	**Weighted Average Remaining Term[(1)]**
	(in millions)		**(in years)**
Chilean Peso (CLP)	28,904	$ 57	1
Argentine Peso (ARS)	91	24	1

(1) Represents the remaining tenor of our foreign currency forwards weighted by the corresponding notional in USD.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

In addition, certain of our subsidiaries have entered into contracts which contain embedded derivatives that require separate valuation and accounting due to the fact that the item being purchased or sold is denominated in currencies other than their own functional currencies or the currency of the item. These contracts range in maturity through 2025. The following table sets forth, by type of foreign currency denomination, the Company s outstanding notional over the remaining terms of its foreign currency embedded derivative instruments as of December 31, 2009:

	December 31, 2009		
Embedded Foreign Currency Derivatives	**Notional**	**Notional Translated to USD**	**Weighted Average Remaining Term[1]**
	(in millions)		**(in years)**
Kazakhstani Tenge (KZT)	44,383	$ 299	11
Philippine Peso (PHP)	2,894	63	4
Euro (EUR)	14	20	3
Argentine Peso (ARS)	69	18	1
Hungarian Forint (HUF)	1,531	8	1
Brazilian Real (BRL)	1	1	<1

(1) Represents the remaining tenor of our foreign currency embedded derivatives weighted by the corresponding notional in USD.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the price of electricity, fuels and environmental credits. Although we primarily consist of businesses with long-term contracts or retail sales concessions (which provide our distribution businesses with a franchise to serve a specific geographic region), a portion of our current and expected future revenues are derived from businesses without significant long-term purchase or sales contracts. These businesses subject our results of operations to the volatility of prices for electricity, fuels and environmental credits in competitive markets. We have used a hedging strategy, where appropriate, to hedge our financial performance against the effects of fluctuations in energy commodity prices. The implementation of this strategy can involve the use of commodity forward contracts, futures, swaps and options. Some of our businesses hedge certain aspects of their commodity risks using financial hedging instruments.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

We also enter into short-term contracts for the supply of electricity and fuel in other competitive markets in which we operate. When hedging the output of our generation assets, we have power purchase agreements or other hedging instruments that lock in the spread in dollars per MWh between the cost of fuel to generate a unit of electricity and the price at which the electricity can be sold. The portion of our sales and fuel purchases that are not subject to such agreements will be exposed to commodity price risk. Eastern Energy in New York and Deepwater in Texas, two of our North America generation businesses, sell electricity into the power pools managed by the New York Independent System Operator (NYISO) and the Electric Reliability Council of Texas (ERCOT), respectively. In addition, Eastern Energy has hedged a portion of its power exposure for 2010 by entering into hedges of natural gas prices, as movements in natural gas prices affect power prices. While there is a strong relationship between natural gas and power prices, the natural gas hedges do not currently qualify for hedge accounting treatment. The following table sets forth the Company s current notionals under its commodity derivative instruments at Eastern Energy and Deepwater and the percentage of forecasted sales of electricity hedged as of December 31, 2009 for 2010 and 2011:

	December 31, 2009			
	2010		2011	
Commodity Hedges	Notional (in millions)	% of Forecasted Sales Hedged	Notional (in millions)	% of Forecasted Sales Hedged
Natural gas swaps (MMBtu)	22	29%		0%
NYISO electricity swaps (MWh)	2	20%	<1	<1%
ERCOT electricity forwards (MWh)	<1	21%		0%

In addition, certain of our subsidiaries have entered into PPAs and fuel supply agreements that have been assessed as derivatives or contain embedded features that have been assessed as embedded derivatives. These contracts range in maturity through 2024. The following table sets forth by type of commodity, the Company s outstanding notional for the remaining term of its commodity derivative (excluding Eastern Energy and Deepwater) and embedded derivative instruments as of December 31, 2009:

	December 31, 2009	
Commodity Derivatives	Notional (in millions)	Weighted Average Remaining Term[1] (in years)
Natural gas (MMBtu)	101	9
Petcoke (Metric tons)	15	14
Coal (Metric tons)	1	1
Log wood (Tons)	<1	3

(1) Represents the remaining tenor of our commodity and embedded derivatives weighted by the corresponding volume.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

Accounting and Reporting

The Company has elected not to offset net derivative positions in the financial statements. Accordingly, the Company does not offset such derivative positions against the fair value of amounts (or amounts that approximate fair value) recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements. At December 31, 2009 and 2008, we held $8 million and $0 million, respectively, of cash collateral that we received from counterparties to our derivative positions, which is recorded in restricted cash and in accrued and other liabilities in the consolidated balance sheets. Also, at December 31, 2009 and 2008, we had no cash collateral posted with (held by) counterparties to our derivative positions.

As of December 31, 2009, approximately $(124), $0, $(2) and $19 million of the pre-tax accumulated other comprehensive (loss) income related to interest rate derivative instruments, cross currency derivative instruments, foreign currency derivative instruments and commodity derivative instruments, respectively, is expected to be recognized as a (decrease) increase to income from continuing operations before income taxes over the next twelve months. The balance in accumulated other comprehensive loss related to derivative transactions will be reclassified into earnings as interest expense is recognized for interest rate hedges and cross currency swaps, as depreciation is recognized for interest rate hedges during construction, as foreign currency transaction and translation gains and losses are recognized for hedges of foreign currency exposure, and as electric sales and fuel purchases are recognized for hedges of forecasted electric and fuel transactions. These balances are included in the consolidated statements of cash flows as operating and/or investing activities based on the nature of the underlying transaction. Additionally, $1 million of pre-tax accumulated other comprehensive (loss) income is expected to be recognized as an increase to income from continuing operations before income taxes over the next twelve months. This amount relates to a power purchase agreement that was dedesignated as a cash flow hedge because the normal purchase normal sale scope exception from derivative accounting was elected as of December 31, 2008.

For the years ended December 31, 2009, 2008 and 2007, pre-tax gains (losses) of $7, $(1) and $(2) million net of noncontrolling interests, respectively were reclassified into earnings as a result of the discontinuance of a cash flow hedge because it was probable that the forecasted transaction would not occur by the end of the originally specified time period (as documented at the inception of the hedging relationship) or within an additional two-month time period thereafter.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following table sets forth the Company s investments in derivative instruments as of December 31, 2009 by type of derivative and by level within the fair value hierarchy. Financial assets and liabilities have been classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessments of the significance of a particular input to the fair value measurement requires judgment, and may affect the determination of the fair value of the assets and liabilities and their placement within the fair value hierarchy levels.

	December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets				
Current assets:				
Foreign exchange derivatives	$	$ 6	$	$ 6
Commodity derivatives				
Electricity		22		22
Fuel			27	27
Other			1	1
Total current assets		28	28	56
Noncurrent assets:				
Interest rate derivatives		83	2	85
Total noncurrent assets		83	2	85
Total assets	$	$ 111	$ 30	$ 141
Liabilities				
Current liabilities:				
Interest rate derivatives	$	$ 135	$ 7	$ 142
Foreign exchange derivatives		3		3
Commodity derivatives				
Electricity		2		2
Fuel			2	2
Other		5		5
Total current liabilities		145	9	154
Noncurrent liabilities:				
Interest rate derivatives		173	7	180
Cross currency derivatives			12	12
Foreign exchange derivatives		2		2
Commodity derivatives: Fuel			2	2
Total noncurrent liabilities		175	21	196

Total liabilities	$	$ 320	$ 30	$ 350

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following table sets forth, by type of derivative, the financial statement location and fair value of derivative instruments as of December 31, 2009:

	December 31, 2009	
	Designated as Hedging Instruments	Not Designated as Hedging Instruments
	(in millions)	
Assets		
Other current assets		
Foreign exchange derivatives	$	$ 6
Commodity derivatives:		
Electricity	22	
Fuel		27
Other		1
Total other current assets	22	34
Other assets		
Interest rate derivatives	85	
Total other current assets noncurrent	85	
Total assets	$ 107	$ 34
Liabilities		
Accrued and other liabilities		
Interest rate derivatives	$ 132	$ 10
Foreign exchange derivatives	2	1
Commodity derivatives:		
Electricity	2	
Fuel		2
Other		6
Total accrued and other liabilities current	136	19
Other long-term liabilities		
Interest rate derivatives	163	16
Cross currency derivatives	12	
Foreign exchange derivatives		2
Commodity derivatives: Fuel		2
Total other long-term liabilities	175	20

Total liabilities	$ 311	$ 39

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following tables set forth, by type of derivative, the financial statement location and amount of gains (losses) recognized in accumulated other comprehensive loss (AOCL) and earnings related to the effective portion of derivative instruments in qualifying cash flow hedging relationships, as defined in the accounting standards for derivatives and hedging, for the year ended December 31, 2009:

	December 31, 2009		
	Gains (Losses) Recognized in AOCL on Derivatives (in millions)	Location of Gains (Losses) Reclassified from AOCL into Earnings	Gains (Losses) Reclassified from AOCL (in millions)
Interest rate derivatives	$ 26	Interest expense	$ (106)[1]
Cross currency derivatives	47	Interest expense	2
		Foreign currency transaction gains (losses)	42
Foreign currency derivatives	(2)	Foreign currency transaction gains (losses)	[2]
Commodity derivatives electricity	120	Non-regulated revenue	193
Total	$ 191		$ 131

(1) Excludes $22 million of losses for the year ended December 31, 2009 reclassified from AOCL related to derivative instruments that previously, but no longer, qualify for cash flow hedge accounting.

(2) De minimis amount of losses reclassified from AOCL.

Amounts recognized in AOCL due to derivative instruments that currently are, or previously were (but no longer are), in qualifying cash flow hedging relationships, as defined in the accounting standards for derivatives and hedging, after income taxes, during the years ended December 31, 2008 and 2007, respectively, are as follows:

	Balance, January 1	Reclassification to earnings	Change in fair value	Balance, December 31
	(in millions)			
2008	$ (232)	$ 76	$ (107)	$ (263)
2007	(113)	(52)	(67)	(232)

The following table sets forth, by type of derivative, the financial statement location and amount of gains (losses) recognized in earnings related to the ineffective portion of derivative instruments in qualifying cash flow hedging relationships, as defined in the accounting standards for derivatives and hedging, for the year ended December 31, 2009:

	December 31, 2009	
	Location of Gains (Losses)	Amount of Gains (Losses) Recognized in Earnings

	Recognized in Earnings	
		(in millions)
Interest rate derivatives	Interest expense	$ 22
Cross currency derivatives	Interest expense	(10)
Commodity derivatives electricity	Non-regulated revenue	(2)
Total		$ 10

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The Company recognized after-tax (losses) gains of $(45) million and $3 million net of noncontrolling interests related to the ineffective portion of derivative instruments in qualifying cash flow hedging relationships, as defined in the accounting standards for derivatives and hedging, for the years ended December 31, 2008 and 2007, respectively.

The following table sets forth by type of derivative, the financial statement location and amount of gains (losses) recognized in earnings related to derivative instruments not designated as hedging instruments under the accounting standards for derivatives and hedging, for the year ended December 31, 2009:

	December 31, 2009		
	Location of Gains (Losses) Recognized in Earnings	Amount of Gains (Losses) Recognized in Earnings (in millions)	
Interest rate derivatives	Interest expense	$	(25)
Foreign exchange derivatives	Non-regulated cost of sales		(6)
	Foreign currency transaction gains (losses)		(32)
Commodity derivatives PPA embedded	Non-regulated revenue		(5)
Commodity derivatives electricity	Non-regulated revenue		6
	Other income		8
Commodity derivatives fuel	Non-regulated cost of sales		(32)
Commodity derivatives other	Non-regulated revenue		(6)
Total		$	(92)

In addition, IPL has two derivative instruments for which the gains and losses are accounted for in accordance with accounting standards for regulated operations, as regulatory assets or liabilities. Gains and losses on these derivatives due to changes in the fair value of these derivatives are probable of recovery through future rates and are initially recognized as an adjustment to the regulatory asset or liability and recognized through earnings when the related costs are recovered through IPL s rates. Therefore, these gains and losses are excluded from the above table. For the year ended December 31, 2009, the change in the fair value of these derivatives resulted in a decrease in regulatory assets of $2 million and a decrease in regulatory liabilities of $5 million on the accompanying consolidated balance sheet.

The Company recognized after-tax gains (losses) of $10 million and $(21) million net of noncontrolling interests related to the changes in fair value of derivative instruments not in qualifying cash flow hedging relationships, as defined in the accounting standards for derivatives and hedging, for the years ended December 31, 2008 and 2007, respectively.

Credit Risk-Related Contingent Features

Certain of our businesses have derivative agreements that contain credit contingent provisions which would permit the counterparties with which we are in a net liability position to require collateral credit support when the fair value of the derivatives exceeds the unsecured thresholds established in the agreements. These thresholds vary based on the subsidiaries credit ratings and as their credit ratings are lowered the thresholds decrease, requiring more collateral support.

Eastern Energy, our generation business in New York, enters into commodity derivative transactions with several counterparties who have market exposure limits defined in their transaction agreements. Pursuant to the

174

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

aforementioned credit contingent provisions, if Eastern Energy s credit rating were to fall below the minimum thresholds established in each of the respective transaction agreements, the counterparties could demand immediate collateralization of the entire mark-to-market value of the derivatives (excluding credit valuation adjustments) if they were in a net liability position. As of December 31, 2009, Eastern Energy had net liability positions of $2 million and had posted a nominal amount of collateral to support these positions based on its current credit rating and the related thresholds in the agreements.

In December 2007, Gener entered into cross currency swap agreements with a counterparty to swap the Chilean inflation indexed bonds issued in December 2007 into U.S. Dollars. Pursuant to the aforementioned credit contingent provisions, if Gener s credit rating were to fall below the minimum threshold established in the swap agreements, the counterparty can demand immediate collateralization of the entire mark-to-market value of the swaps (excluding credit valuation adjustments) if Gener is in a net liability position, which was $12 million at December 31, 2009. As of December 31, 2009, Gener had posted $25 million in the form of a letter of credit to support these swaps.

6. FAIR VALUE

The fair value of current financial assets and liabilities, debt service reserves and other deposits is estimated to be equal to their reported carrying amounts. The fair value of non-recourse debt is estimated differently based upon the type of loan. For variable rate loans, carrying value approximates fair value. For fixed rate loans, the fair value is estimated using quoted market prices or discounted cash flow analyses. See Note 10 Debt for additional information on the fair value and carrying value of debt. The fair value of interest rate swap, cap and floor agreements, foreign currency forwards, swaps and options, and energy derivatives is the estimated net amount that the Company would receive or pay to sell or transfer agreements as of the balance sheet date.

The estimated fair values of the Company s assets and liabilities have been determined using available market information. By virtue of these amounts being estimates and based on hypothetical transactions to sell assets or transfer liabilities, the use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts.

In general, the Company s nonfinancial assets and liabilities that are measured at fair value on a nonrecurring basis include goodwill; intangible assets, such as sales concessions, land rights and emissions allowances; and long-lived tangible assets including property, plant and equipment. The Company recognized material goodwill impairment during the year ended December 31, 2009 as a result of the annual goodwill impairment evaluation as of October 1, but this impairment was not a result of the adoption of the new fair value measurement provisions. This is further described in Note 8 Goodwill and Other Intangible Assets. Although the adoption of the new fair value measurement and disclosure accounting guidance did not materially impact our financial condition, results of operations or cash flows, additional disclosures about fair value measurements are included in this Form 10-K.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following table summarizes the carrying and fair value of certain of the Company s financial assets and liabilities as of December 31, 2009 and 2008:

	December 31,			
	2009		2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Assets				
Marketable securities[(1)]	$ 1,691	$ 1,691	$ 1,413	$ 1,413
Derivatives[(2)]	141	141	350	350
Total assets	$ 1,832	$ 1,832	$ 1,763	$ 1,763
Liabilities				
Debt[(3)]	$ 19,916	$ 20,387	$ 17,690	$ 15,249
Derivatives[(2)]	350	350	504	504
Total liabilities	$ 20,266	$ 20,737	$ 18,194	$ 15,753

(1) See Note 4 Investments in Marketable Securities for additional information regarding the classification of marketable securities in the Fair Value Hierarchy.

(2) See Note 5 Derivative Instruments and Hedging Activities for additional information regarding the fair value of derivatives.

(3) See Note 10 Debt for additional information regarding the fair value of the Company s recourse and non-recourse debt.

Valuation Techniques:

The fair value measurement accounting guidance describes three main approaches to measuring the fair value of assets and liabilities: (1) market approach; (2) income approach and (3) cost approach. The market approach uses prices and other relevant information generated from market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to convert future amounts to a single present value amount. The measurement is based on the value indicated by current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace an asset. The Company does not currently determine the fair value of any of our financial assets and liabilities using the cost approach. Financial assets and liabilities that are measured at fair value on a recurring basis at AES fall into two broad categories: investments and derivatives.

Our investments are generally measured at fair value using the market approach and our derivatives are valued using the income approach.

Investments

The Company s investments measured at fair value generally consist of marketable debt and equity securities. Equity securities are adjusted to fair value using quoted market prices. Debt securities primarily consist of unsecured debentures, certificates of deposit and government debt securities held by our Brazilian subsidiaries. The implementation of the fair value measurement guidance did not result in a material change in the fair value of these investments due to the fact that these investments are primarily issued by highly-rated institutions and governmental agencies and therefore, the consideration of counterparty credit risk did not have a

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

material impact on the determination of fair value. Returns and pricing on these instruments are generally indexed to the CDI (Brazilian equivalent to LIBOR), Selic (overnight borrowing rate) or IGPM (inflation) rates in Brazil and are adjusted based on the banks assessment of the specific businesses. Fair value is determined based on comparisons to market data obtained for similar assets and are considered Level 2 inputs. The Company holds some auction rate securities through IPL. The fair value of these securities was $2 million as of December 31, 2009. Based on the current credit environment, these were evaluated for potential impairment and were determined to not be impaired at this time. For more detail regarding the fair value of investments see Note 4 Investments in Marketable Securities.

Derivatives

When deemed appropriate, the Company manages its risk from interest and foreign currency exchange rate and commodity price fluctuations through the use of financial and physical derivative instruments. The Company s derivatives are primarily interest rate swaps to hedge non-recourse debt to establish a fixed rate on variable rate debt, foreign exchange instruments to hedge against currency fluctuations, commodity derivatives to hedge against fluctuations in commodity prices, and embedded derivatives associated with commodity contracts. The Company s subsidiaries are counterparties to various interest rate swaps, interest rate options, foreign currency swaps and commodity and embedded derivatives in certain agreements, generally PPAs. The fair value of our derivative portfolio was determined using internal valuation models, most of which are based on observable market inputs including interest rate curves and forward and spot prices for currencies and commodities. The primary pricing inputs used in determining the fair value of our interest rate swaps and our foreign currency exchange swaps are forward LIBOR curves and forward foreign exchange curves with the same duration as the instrument as reported in published information provided by pricing services. For each derivative, the projected forward curves are used to determine the stream of cash flows over the remaining term of the contract. The cash flows are then discounted using a spot discount rate to determine the fair value. To the extent that management can estimate the fair value of these assets or liabilities without the use of significant unobservable inputs, these derivatives are included in Level 2.

In certain instances, the published curve may not extend through the remaining term of the contract and management must make assumptions to extrapolate the curve which result in the use of unobservable inputs. In certain instances the financial or physical instrument is traded in an inactive market requiring us to use unobservable inputs. Additionally, in certain instances the nonperformance risk or credit risk adjustment for contracts is based on unobservable inputs. Where the use of such unobservable inputs are significant, these contracts are classified as Level 3.

Fair Value Considerations:

In determining the fair value of our financial instruments, the Company considers the source of observable market data inputs, liquidity of the instrument, the credit risk of the counterparty to the contract and risk of nonperformance of itself. The conditions and criteria used to assess these factors are:

Sources of market assumptions:

The Company derives most of its financial instrument market assumptions from market efficient data sources (e.g., Bloomberg and Platt s). In some cases, where market data is not readily available, management uses comparable market sources and empirical evidence to derive market assumptions to determine a financial instrument s fair value.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

Market liquidity:

Market liquidity is evaluated by the Company based on criteria as to whether the financial or physical instrument, or the underlying asset, is traded in an active or inactive market. An active market exists if the prices are fully transparent to market participants, can be measured by market bid and ask quotes, the market has a relatively large proportion of trading volume as compared to the Company s current trading volume and the market has a significant number of market participants that will allow the market to rapidly absorb the quantity of the assets traded without significantly affecting the market price. Other factors the Company considers when determining whether a market is active or inactive include the presence of government or regulatory control over pricing that could make it difficult to establish a market based price upon entering into a transaction.

Nonperformance risk:

Nonperformance risk refers to the risk that the obligation will not be fulfilled and affects the value at which a liability is transferred or an asset is sold. Nonperformance risk includes, but may not be limited to, the Company or counterparty s credit risk and settlement risk. Nonperformance risk adjustments are dependent on credit spreads, letters of credit, collateral, other arrangements available and the nature of master netting arrangements. The Company and its subsidiaries are parties to various interest rate swaps and options; foreign currency forwards, swaps, and options and derivatives and embedded derivatives which subject the Company to nonperformance risk. The financial and physical instruments held at the subsidiary level are generally non-recourse to the Parent Company.

Nonperformance risk on the investments held by the Company is incorporated in the investment s exit price that is derived from quoted market data that is used to mark the investment to fair value.

The Company adjusts for nonperformance risk or credit risk on its derivative instruments by deducting a credit valuation adjustment (CVA). The CVA is based on the margin or debt spread of the Company or counterparty and the tenor of the respective derivative instrument. The counterparty for a derivative asset position is considered to be the bank or government sponsored banking entity or counterparty to the PPA or commodity contract. The CVA for asset positions is based on the counterparty s credit ratings and debt spreads or, in the absence of readily obtainable credit information, the respective country debt spreads are used as a proxy. The CVA for liability positions is based on the Parent Company s or the subsidiary s current debt spread, the margin on indicative financing arrangements, or in the absence of readily obtainable credit information, the respective country debt spreads is used as a proxy. If the instrument is recourse to the Parent Company, the Parent Company s current debt spread is used to adjust for nonperformance risk. All derivative instruments are analyzed individually and are subject to unique risk exposures.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following table sets forth, by level within the fair value hierarchy, the Company s financial assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2009. Financial assets and liabilities have been classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the determination of the fair value of the assets and liabilities and their placement within the fair value hierarchy levels.

	Total	Quoted Market Prices in Active Market for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(in millions)		
Assets				
Available-for-sale securities	$ 1,676	$ 133	$ 1,501	$ 42
Trading securities	7	7		
Derivatives	141		111	30
Total assets	$ 1,824	$ 140	$ 1,612	$ 72
Liabilities				
Derivatives	$ 350	$	$ 320	$ 30
Total liabilities	$ 350	$	$ 320	$ 30

The following table presents a reconciliation of all assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the year ended December 31, 2009:

	Derivatives	Available-for-Sale Securities(5)
	(in millions)	
Balance at January 1, 2009(1)	$ (69)	$ 42
Total gains/losses (realized/unrealized)(1)		
Included in earnings(2)	(8)	
Included in other comprehensive income	127	
Included in regulatory assets	2	
Purchases, sales, issuances and settlements(1)	(40)	
Assets transferred in (out) of Level 3	(241)(3)	
Liabilities transferred (in) out of Level 3	229(4)	
Balance at December 31, 2009(1)	$	$ 42
Total gains/losses for the period included in earnings attributable to the change in unrealized gains/losses relating to assets and liabilities held at both the beginning and end of the period(1)	$ 3	$

(1) Derivative assets and (liabilities) are presented on a net basis.

(2) See Note 5 Derivative Instruments and Hedging Activities for further information regarding the classification of gains and losses included in earnings in the Consolidated Statements of Operations.

(3) Of the assets transferred out of Level 3 during the year ended December 31, 2009, $187 million represents a PPA that was dedesignated as a cash flow hedge because it qualified for the normal purchase normal sale scope exception as of December 31, 2008. As such, the agreement was measured at fair value using significant unobservable inputs at December 31, 2008, but is subsequently being

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

amortized and is no longer adjusted for subsequent changes in fair value. The remainder of assets transferred out of Level 3 were primarily a result of a decrease in the significance of unobservable inputs used to calculate the credit valuation adjustments of these derivative instruments.

(4) Liabilities transferred out of Level 3 were primarily a result of a decrease in the significance of unobservable inputs to calculate the credit valuation adjustments of these derivative instruments.

(5) Available-for-sale securities in Level 3 are auction rate securities and variable rate demand notes which have failed remarketing, or are not actively trading, and for which there are no longer adequate observable inputs available to measure the fair value.

Nonfinancial Assets and Liabilities on a Nonrecurring Basis

For the purpose of impairment evaluation, the Company measured goodwill and intangibles assets, long-lived assets, and discontinued operations and assets held for sale at fair value under the new fair value measurement accounting guidance. As the majority of significant assumptions used for these valuations were not observable, management believes that all of these valuation are level 3 measurements in the fair value hierarchy.

As noted in Note 19 Asset Impairment Expense, long-lived assets held and used with a carrying amount of $26 million were written down to their fair value of $2 million, resulting in an asset impairment charge of $24 million, which was included in net income for the year.

As noted in Note 8 Goodwill and Other Intangible Assets, goodwill with an aggregate carrying amount of $122 million was written down to its implied fair value of $0 million, resulting in goodwill impairment of $122 million, which was included in net income for the year.

As noted in Note 21 Discontinued Operations and Held for Sale Businesses, long-lived assets held for sale with a carrying amount of $275 million were written down to their fair value of $130 million, less cost to sell of $5 million (or $125 million), resulting in a loss of $150 million, which was included in net income for the year.

7. INVESTMENTS IN AND ADVANCES TO AFFILIATES

The following table summarizes the relevant effective equity ownership interest and carrying values for the Company s investments accounted for under the equity method as of December 31, 2009 and 2008.

		December 31,			
Affiliate	**Country**	**2009**	**2008**	**2009**	**2008**
		Carrying Value		**Ownership Interest %**	
Barry[1]	United Kingdom	$	$	100	100
Cartagena[1]	Spain			71	71
CEMIG	Brazil			10	10
AES Solar Ltd.	United States	224	126	50	50
Chigen affiliates	China	182	179	27	27
Elsta	Netherlands	204	138	50	50
Guacolda	Chile	131	81	35	35
Huanghua	China	52	36	49	49
IC Ictas Energy Group	Turkey	104	94	51	51
InnoVent[1]	France	30	37	40	40
OPGC	India	208	192	49	49
Trinidad Generation Unlimited[1]	Trinidad	16	16	10	60
Other affiliates	United States	6	2		

Total investments in and advances to affiliates	$ 1,157	$ 901

(1) Represent VIEs in which we hold a significant variable interest.

180

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

AES Barry Ltd. The Company holds a 100% ownership interest in AES Barry Ltd. (Barry), a dormant entity in the United Kingdom that disposed of its generation and other operating assets. As a result of a debt agreement, no material financial or operating decisions can be made without the banks consent, and the Company does not control Barry. As of December 31, 2009 and 2008 other long-term liabilities included $54 million and $49 million, respectively, related to this debt agreement.

Cartagena Energia The Company owns 71% of Cartagena Energia (Cartagena) a 1,219 MW power plant in Cartagena, Spain completed in November 2007. The Company s initial investment in Cartagena was approximately $29 million. Cartagena was determined to be a VIE and the Company is not the primary beneficiary due to the fact that the sole customer of the plant absorbs the majority of the commodity price risk. In December 2008, the Company s basis in its investment in Cartagena was reduced to zero and the equity method of accounting was suspended. In June 2009, Cartagena received a cash settlement of $53 million for liquidated damages including legal costs incurred related to the construction delay from December 2005 to November 2006 of the generation plant. Cartagena used the settlement proceeds to repay a portion of the participative loans outstanding to its investors including AES. In June 2009, the Company received its proportionate share of the settlement, $35 million, which was recognized as net equity in earnings of affiliates because the distribution was in excess of the Company s current investment balance of zero and AES does not have an obligation or intent to fund future cash flow requirements of Cartagena. As a result of the new accounting guidance issued in the fourth quarter of 2009 regarding VIEs, the Company believes at this time that upon the January 1, 2010 effective date, Cartagena will no longer be accounted for under the equity method of accounting, and will at that time become a consolidated subsidiary. See further discussion of the new accounting guidance in Item 7. *Management s Discussion and Analysis of Financial Condition*, Accounting Pronouncements Issued, but not yet Effective and Note 1 General and Summary of Significant Accounting Policies.

CEMIG The Company, through it s Brazilian subsidiary, Southern Electric Brasil Participações Ltda. (SEB), a VIE, has a 14.8% voting interest in Companhia Energética de Minas Gerais (CEMIG), an integrated utility in Minas Gerais, Brazil. Although our interest in CEMIG is below the 20% threshold for significant influence, AES has significant influence over the operational and financial policies of CEMIG through representation on the board of directors of CEMIG. In 2002, the Company determined there was an other-than-temporary impairment of its investment in CEMIG and wrote it down to fair market value, $155 million. Additionally, AES established a valuation allowance against a deferred tax asset related to the CEMIG investment. The total amount of these charges, net of tax, was $587 million. As a result, the Company s investment in CEMIG is a $484 million net liability at December 31, 2009 included in the Other Long-Term Liabilities line item on the Consolidated Balance Sheet. The Company has discontinued the application of the equity method in accordance with its accounting policy regarding equity method investments. In November 2009, SEB entered into a share purchase and sale agreement with Andrade Gutierrez Concessões S.A. and an affiliated company (jointly referred to as, AG) for the sale of SEB s shares in CEMIG. In consideration for SEB s shares in CEMIG, AG will pay to SEB a total purchase price equal to the sum of (i) $25 million plus (ii) the assumption by AG of SEB s debt (the BNDES Loan) with Banco Nacional de Desenvolvimento Econômico e Social (BNDES). The sale is subject to the resolution of all outstanding debts and claims relating to the BNDES Loan and is contingent upon SEB obtaining a full release from any claims of BNDES, the restructuring of the BNDES Loan and the ratification of the settlement by the judicial system of the restructuring of the BNDES Loan assumed by AG and the sale of SEB s shares in CEMIG to AG.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

AES Solar Energy Ltd. In March 2008, the Company formed AES Solar Energy Ltd (AES Solar), a joint venture with Riverstone Holdings LLC (Riverstone). AES Solar will develop land-based solar photovoltaic panels that capture sunlight to convert into electricity that feed directly into power grids. AES Solar is accounted for under the equity method of accounting based on the Company s 50% ownership and significant influence but not control over the joint venture. Under the terms of the agreement, the Company and Riverstone will each provide up to $500 million of capital over the next five years. As of December 31, 2009, AES had invested approximately $247 million in the joint venture.

Guohua AES (Huanghua) Wind Power Co., Ltd In May 2007, the Company acquired a 49% interest in Guohua AES (Huanghua) Wind Power Co., Ltd. (AES Huanghua), a joint venture that is primarily engaged to develop, construct, own and operate wind projects in China. The project went live in the third quarter of 2009. Also, in the second and third quarter of 2008, the Company acquired a 49% interest in three separate wind projects in China Guohua AES (Hulunbeier) Wind Power Co., Ltd.; Guohua AES (Chenba erhu) Wind Power Co., Ltd.; and Guohua AES (Xinba erhu) Wind Power Co., Ltd. The Company invested approximately $16 million in the aforementioned projects in 2009, bringing the cumulative investment to $50 million.

Trinidad Generation Unlimited In 2007, the Company began pursuing a development project to construct and operate a 720 MW combined cycle power plant in Trinidad through its wholly owned subsidiary, Trinidad Generation Unlimited (TGU.) In July 2008, a shareholder agreement was executed establishing the Company s ownership interest in TGU at 60% with the remaining 40% interest held by the Government of Trinidad and Tobago. Although the Company s ownership in TGU was reduced to 10% in 2009, the Company continues to account for its investment in Trinidad as an equity method investment because AES continues to exercise significant influence through the supermajority vote requirement for any significant future project development activities.

Summarized Financial Information

The following tables summarize financial information of the Company s 50%-or-less owned affiliates and majority-owned unconsolidated subsidiaries that are accounted for using the equity method.

	50%-or-less Owned Affiliates			Majority-Owned Unconsolidated Subsidiaries		
Years ended December 31,	**2009**	**2008**	**2007**	**2009**	**2008**	**2007**
		(in millions)			**(in millions)**	
Revenue	$ 1,229	$ 1,180	$ 988	$ 158	$ 170	$ 145
Gross margin	240	274	255	71	61	57
Net income (loss)	110	83	194	(5)	(4)	(17)

December 31,	**2009**	**2008**	**2009**	**2008**
	(in millions)		**(in millions)**	
Current assets	$ 882	$ 734	$ 142	$ 222
Noncurrent assets	3,543	2,626	1,140	1,297
Current liabilities	528	563	153	181
Noncurrent liabilities	1,406	1,264	1,055	1,072
Noncontrolling interests	191	163	24	26
Stockholders equity	2,682	1,696	98	292

At December 31, 2009, retained earnings included $156 million related to the undistributed earnings of the Company s 50%-or-less owned affiliates. Distributions received from these affiliates were $35 million, $50 million and $59 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Refer to Item 1 of this Form 10-K for additional information on these affiliates.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

8. GOODWILL AND OTHER INTANGIBLE ASSETS

The accounting guidance for goodwill requires that goodwill be evaluated for impairment at the reporting unit level. A reporting unit is an operating segment, as defined by the segment reporting accounting guidance, or a component or combination of components within an operating segment with similar economic characteristics that are one level below an operating segment. Generally, each AES business constitutes a reporting unit. In the event that more than one reporting unit is acquired in a single acquisition, goodwill is assigned to the reporting units that benefit from the goodwill on a relative fair value basis.

The following table summarizes the changes in the carrying amount of goodwill, by segment as of December 31, 2009, 2008 and 2007. There was no goodwill associated with our North America Utilities segment during the years ended December 31, 2009, 2008 and 2007.

	Latin America - Generation	Latin America - Utilities	North America - Generation	Europe - Generation	Asia - Generation	Corporate and Other	Total
Balance as of December 31, 2007							
Goodwill	$ 929	$ 140	$ 130	$ 167	$ 24	$ 98	$ 1,488
Accumulated impairment losses	(24)	(7)	(20)	(19)		(2)	(72)
Net balance	905	133	110	148	24	96	1,416
Goodwill acquired during the year					65[1]	6	71
Goodwill associated with the sale of a business					(4)		(4)
Foreign currency translation and other	(3)		(9)	(40)	(7)	(3)	(62)
Balance as of December 31, 2008							
Goodwill	926	140	121	127	78	101	1,493
Accumulated impairment losses	(24)	(7)	(20)	(19)		(2)	(72)
Net balance	902	133	101	108	78	99	1,421
Impairment losses				(118)		(4)	(122)
Goodwill associated with the sale of a business					(2)		(2)
Foreign currency translation and other			(10)	10	2		2
Balance as of December 31, 2009							
Goodwill	926	140	111	137	78	101	1,493
Accumulated impairment losses	(24)	(7)	(20)	(137)		(6)	(194)
Net balance	$ 902	$ 133	$ 91	$	$ 78	$ 95	$ 1,299

(1) Represents goodwill acquired for the period of $65 million related to the acquisition of Masinloc.

The Company conducts its annual goodwill impairment analysis as of October 1st each year. The fair value of the reporting units was determined using the income approach based on a discounted cash flow valuation model as current quoted market prices were not always available. In 2009, Kilroot, our subsidiary in the United Kingdom, reported in the Europe Generation segment, incurred goodwill impairment loss of $118 million. Kilroot is a generation plant fired primarily by coal. Factors contributing to the impairment included: reduced profit expectations based on latest estimates of future commodity prices and reduced expectations on the

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

recovery of cash flows on the existing plant following the Company s decision to forgo capital expenditures to meet emission allowance requirements taking effect in 2024. Additionally, one of our subsidiaries located in the Ukraine and reported within Corporate and Other incurred a goodwill impairment loss of $4 million. For the years ended December 31, 2008 and 2007, the Company had no goodwill impairment.

The following tables summarize the balances comprising other intangibles in the accompanying Consolidated Balance Sheets for the years ended December 31, 2009 and 2008:

	December 31, 2009			December 31, 2008		
	Gross Balance	Accumulated Amortization	Net Balance	Gross Balance	Accumulated Amortization	Net Balance
		(in millions)			(in millions)	
Sales concessions[1]	$ 167	$ (84)	$ 83	$ 165	$ (77)	$ 88
Land use rights[1][2]	97	(1)	96	94	(1)	93
Management rights[1]	64	(27)	37	27	(17)	10
Emission allowances[3]	33		33	45		45
Intangible assets related to asset purchase[1][4]	253	(83)	170	245	(72)	173
Other[1][5]	119	(28)	91	110	(19)	91
Total	$ 733	$ (223)	$ 510	$ 686	$ (186)	$ 500

(1) Intangible assets subject to amortization.

(2) Includes $50 million land use rights that are not subject to amortization at December 31, 2009 and 2008. The remaining balance is subject to amortization.

(3) Acquired or purchased emission allowances are expensed when utilized or sold and included in net income for the year.

(4) Represents various intangible assets subject to amortization relating to an asset acquisition in the state of New York in 1999, which were not separately identified.

(5) Consists of various intangible assets including PPAs subject to amortization, none of which is individually significant.

In 2009, the Company reclassified $42 million from other assets into the intangible asset at one subsidiary in Latin America. In 2009, the Company acquired intangible assets of $22 million. The acquired intangible assets included $1 million which were subject to amortization with an average amortization period of 35 years and $21 million of intangible assets not subject to amortization. In 2008, the Company acquired intangible assets of $85 million, the largest of which was the acquisition of landfill gas rights in El Salvador. The acquired intangible assets included $59 million which were subject to amortization with an average amortization period of 20 years and $26 million of intangible assets not subject to amortization.

The following table summarizes the estimated amortization expense, broken down by intangible asset category, for 2010 through 2014:

	Estimated amortization expense				
	2010	2011	2012	2013	2014
			(in millions)		
Sales concessions	$ 7	$ 6	$ 6	$ 6	$ 6
All other	17	17	16	15	14

Total	$ 24	$ 23	$ 22	$ 21	$ 20

Intangible asset amortization expense was $24 million, $19 million and $23 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

9. REGULATORY ASSETS & LIABILITIES

The Company has recorded regulatory assets and liabilities that it expects to pass through to its customers in accordance with, and subject to, regulatory provisions as follows:

	December 31, 2009	December 31, 2008	Recovery Period
	(in millions)		
REGULATORY ASSETS			
Current regulatory assets:			
Brazil tariff recoveries[(2)]			
Energy purchases	$ 144	$ 76	Over tariff reset period
Transmission costs, regulatory fees and other	120	121	Over tariff reset period
El Salvador tariff recoveries[(3)]	125	136	Over tariff reset period
Other[(4)]	6	18	Various
Total current regulatory assets	395	351	
Noncurrent regulatory assets:			
Defined benefit pension obligations[(1)(5)]	217	281	Various
Income taxes recoverable from customers[(1)(6)]	70	75	Various
Brazil tariff recoveries[(2)]			
Energy purchases	22	31	Over tariff reset period
Transmission costs, regulatory fees and other	30	48	Over tariff reset period
Other[(4)]	111	106	Various
Total noncurrent regulatory assets	450	541	
TOTAL REGULATORY ASSETS	$ 845	$ 892	
REGULATORY LIABILITIES			
Current regulatory liabilities:			
Efficiency program costs[(7)]	$ 133	$ 116	Over tariff reset period
Brazil tariff recoveries[(2)]			
Energy purchases	61	31	Over tariff reset period
Transmission costs, regulatory fees and other	67	44	Over tariff reset period
Other[(4)]	35	14	Various
Total current regulatory liabilities	296	205	
Noncurrent regulatory liabilities:			
Asset retirement obligations[(8)]	482	459	Over book life of assets
Brazil special obligations[(9)]	402	291	To be determined
Brazil tariff recoveries[(2)]			
Energy purchases	42	8	Over tariff reset period

Transmission costs, regulatory fees and other	35	2	Over tariff reset period
Unamortized investment tax credit(1)(6)	9	10	Various
Efficiency program costs(7)	4		Over tariff reset period
Other(4)	8	9	Various
Total noncurrent regulatory liabilities	982	779	
TOTAL REGULATORY LIABILITIES	$ 1,278	$ 984	

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

(1) Past expenditures on which the Company does not earn a rate of return.

(2) Recoverable per National Electric Energy Agency (ANEEL) regulations through the Annual Tariff Adjustment (IRT). These costs are generally non-controllable costs and primarily consist of purchased electricity, energy transmission costs and sector costs that are considered volatile. These costs are recovered in 24 installments through the annual IRT process and are amortized over the tariff reset period.

(3) Deferred fuel costs incurred by our El Salvador subsidiaries associated with purchase of energy from the El Salvador spot market and the power generation plants. In El Salvador, the deferred fuel adjustment represents the variance between the actual fuel costs and the fuel costs recovered in the tariffs. The variance is recovered semi-annually at the tariff reset period.

(4) Includes assets with and without a rate of return. All current regulatory assets earned a rate of return as of December 31, 2009. Other current regulatory assets that did not earn a rate of return were $9 million as of December 31, 2008. Other noncurrent regulatory assets that did not earn a rate of return were $90 million and $83 million, as of December 31, 2009 and 2008, respectively. Those without a rate of return that are recoverable based on specific rate orders primarily consist of the following:

- Transmission service costs and other administrative costs from IPL s participation in the Midwest ISO market. Recovery of costs is probable, but the timing is not yet determined.

Other Current and Noncurrent Regulatory Liabilities consist of:

- Deferred fuel costs: expected to be refunded to customers through future fuel adjustment charges. In the United States, deferred fuel costs at IPL represent variances between estimated and actual fuel and purchased power costs. IPL is permitted to recover underestimated fuel and purchased power costs in future rates.

- Penalties and fees from regulators at our Brazil subsidiaries and financial transmission rights used to hedge exposure in the Midwest ISO market that are credited per specific rate orders.

- Free Energy is the cost incurred by electricity generators due to variance in energy prices during rationing periods. Our Brazilian subsidiaries are authorized to reclaim or refund this cost associated with monthly energy price variances between the whole sale energy market prices owed to the power generation plants producing free energy and the capped price reimbursed by the local distribution companies which are passed through to the final customers through energy tariffs.

(5) The regulatory accounting standards allow the defined pension and postretirement benefit obligation to be recorded as a regulatory asset equal to the previously unrecognized actuarial gains and losses and prior service costs that are expected to be recovered through future rates. Pension expense is recognized based on the plan s actuarially determined pension liability. Recovery of costs is probable, but not yet determined. The decrease in the regulatory asset of $64 million at December 31, 2009 is primarily a result of a higher than expected return on assets in 2009.

(6) Probable of reversal through future rates, based upon established regulatory practices, which permit the reversal of current taxes. This amount is expected to be recovered, without interest, over the period as book-tax temporary differences reverse and become current taxes.

(7) Payments received for costs expected to be incurred to improve the efficiency of our plants in Brazil that are recovered as part of the IRT.

(8) Non-legal asset retirement obligations for removal costs which do not have an associated legal retirement obligation as defined by the accounting standards on asset retirement obligations.

(9) Obligations established by ANEEL in Brazil associated with electric utility concessions and represent amounts received from customers or donations not subject to return. These donations are allocated to support energy network expansion and to improve utility operations to meet customers needs. The maturity term is established by ANEEL whose settlement shall occur when the concession ends.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The current regulatory assets and liabilities are recorded in other current assets and accrued and other liabilities, respectively, on the accompanying Consolidated Balance Sheets. The noncurrent regulatory assets and liabilities are recorded in other assets and other long-term liabilities, respectively, in the accompanying Consolidated Balance Sheets.

The following table summarizes regulatory assets by region as of December 31, 2009 and 2008:

	December 31, 2009	December 31, 2008
	(in millions)	
Latin America	$ 445	$ 413
North America	400	479
Total regulatory assets	$ 845	$ 892

The following table summarizes regulatory liabilities by region as of December 31, 2009 and 2008:

	December 31, 2009	December 31, 2008
	(in millions)	
Latin America	$ 772	$ 508
North America	506	476
Total regulatory liabilities	$ 1,278	$ 984

10. DEBT

The Company has two types of debt reported on its balance sheet: non-recourse and recourse debt. Non-recourse debt is used to fund investments and capital expenditures for the construction and acquisition of our electric power plants, wind projects and distribution companies at our subsidiaries. Non-recourse debt is generally secured by the capital stock, physical assets, contracts and cash flows of the related subsidiary. The default risk is limited to the respective business and is without recourse to the Parent Company and other subsidiaries. Recourse debt is direct borrowings by the Parent Company and is used to fund development, construction or acquisition and functions as equity investments or loans to the affiliates. This debt is with recourse to the Parent Company and is structurally subordinated to the affiliates non-recourse debt.

Recourse and non-recourse debt is carried at amortized cost. The following table summarizes the carrying amount and estimated fair values of the Company s recourse and non-recourse debt as of December 31, 2009 and 2008:

	December 31, 2009	December 31, 2008

	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(in millions)		
Non-recourse debt	$ 14,401	$ 14,784	$ 12,542	$ 10,861
Recourse debt	5,515	5,603	5,148	4,388
Total debt	$ 19,916	$ 20,387	$ 17,690	$ 15,249

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The fair value of non-recourse debt, excluding capital leases, is estimated differently based upon the type of loan. The fair value of fixed rate loans is estimated using quoted market prices or a discounted cash flow analysis. In the discounted cash flow analysis, the discount rate is based on the credit rating of the individual debt instruments if available, or the credit rating of The AES Corporation. For subsidiaries located in countries with credit ratings lower than The AES Corporation, we used the appropriate country specific yield curve. For variable rate loans, carrying value typically approximates fair value. At December 31, 2008, credit spreads were significantly above historic levels. For the U.S. Dollar, Euro and British Pound markets where the Company believed the expanded credit spread was material, fair value was estimated using a discounted cash flow analysis. The increase in credit spreads was calculated as the difference between composite fair value curves, published by pricing services for the relevant issuer credit rating, and London Inter-Bank Offered Rate (LIBOR). For all other currencies, the Company continued to assume the carrying value was equal to fair value. During the second half of 2009, credit spreads returned to a typical range for all currencies and the Company concluded that carrying value approximated fair value for all of our variable rate debt as of December 31, 2009. The estimated fair value was determined using available market information as of December 31, 2009 and 2008. The Company is not aware of any factors that would significantly affect the estimated fair value amounts since December 31, 2009.

NON-RECOURSE DEBT

The following table summarizes the carrying amount and terms of non-recourse debt of the Company as of December 31, 2009 and 2008:

NON-RECOURSE DEBT	Interest Rate[1]	Maturity	December 31, 2009	December 31, 2008
			(in millions)	
VARIABLE RATE:[2]				
Bank loans	2.33%	2010 - 2027	$ 3,489	$ 3,137
Notes and bonds	10.40%	2010 - 2018	1,922	1,844
Debt to (or guaranteed by) multilateral, export credit agencies or development banks[3]	3.55%	2010 - 2027	1,679	1,089
Other	6.92%	2010 - 2028	930	391
FIXED RATE:				
Bank loans	8.43%	2010 - 2023	446	426
Notes and bonds	8.08%	2010 - 2037	5,450	5,197
Debt to (or guaranteed by) multilateral, export credit agencies or development banks[3]	6.69%	2010 - 2026	406	393
Other	7.02%	2010 - 2039	79	65
SUBTOTAL			$ 14,401[4]	$ 12,542[4]
Less: Current maturities			(1,759)	(917)
TOTAL			$ 12,642	$ 11,625

(1) Weighted average interest rate at December 31, 2009.

(2) The Company has interest rate swaps and interest rate option agreements in an aggregate notional principal amount of approximately $4.2 billion on non-recourse debt outstanding at December 31, 2009. The swap agreements economically change the variable interest rates on the portion of the debt covered by the notional amounts to fixed rates ranging from approximately 1.93% to 6.98%. The option agreements fix interest rates within a range from 4.03% to 7.00%. The agreements expire at various dates from 2010 through 2027.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

(3) Multilateral loans include loans funded and guaranteed by bilaterals, multilaterals, development banks and other similar institutions.
(4) Non-recourse debt of $329 million and $401 million as of December 31, 2009 and 2008, respectively, related to Lal Pir, Pak Gen and Barka was excluded from non-recourse debt and included in current and long-term liabilities of held for sale and discontinued businesses in the accompanying Consolidated Balance Sheets.

Non-recourse debt as of December 31, 2009 is scheduled to reach maturity as set forth in the table below:

December 31,	Annual Maturities (in millions)
2010	$ 1,759
2011	1,271
2012	868
2013	1,054
2014	1,458
Thereafter	7,991
Total non-recourse debt	$ 14,401

As of December 31, 2009, AES subsidiaries with facilities under construction had a total of approximately $1.1 billion of committed but unused credit facilities available to fund construction and other related costs. Excluding these facilities under construction, AES subsidiaries had approximately $1.6 billion in a number of available but unused committed revolving credit lines to support their working capital, debt service reserves and other business needs. These credit lines can be used in one or more of the following ways: solely for borrowings; solely for letters of credit; or a combination of these uses. The weighted average interest rate on borrowings from these facilities was 5.25% at December 31, 2009. In addition to the committed credit lines described above, an operating subsidiary of the Company in Brazil had credit commitments from banks to lend up to $574 million at December 31, 2009. This credit commitment is subject to certain conditions and can only be used if the Company decides to exercise its preemptive rights to acquire the noncontrolling interest shares of Brasiliana held by a third-party in response to a decision by the partner to sell and exercise its preemptive rights to include our ownership portion in the sale.

Non-Recourse Debt Covenants, Restrictions and Defaults

The terms of the Company s non-recourse debt include certain financial and non-financial covenants. These covenants are limited to subsidiary activity and vary among the subsidiaries. These covenants may include but are not limited to maintenance of certain reserves, minimum levels of working capital and limitations on incurring additional indebtedness. Compliance with certain covenants may not be objectively determinable.

As of December 31, 2009 and 2008, approximately $653 million and $689 million, respectively, of restricted cash was maintained in accordance with certain covenants of the debt agreements, and these amounts were included within restricted cash and debt service reserves and other deposits in the accompanying Consolidated Balance Sheets.

Various lender and governmental provisions restrict the ability of the Company s subsidiaries to transfer their net assets to the Parent Company. Such restricted net assets of subsidiaries amounted to approximately $5.8 billion at December 31, 2009.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following table summarizes the Company s subsidiary non-recourse debt in default or accelerated as of December 31, 2009 and is included in the current portion of non-recourse debt unless otherwise indicated:

Subsidiary	Primary Nature of Default	December 31, 2009 Default	Net Assets
		(in millions)	
Sonel	Covenant	$ 340	$ 229
Jordan	Covenant	225	66
Kelanitissa	Covenant	39	14
Ebute[1]	Covenant	8	154
Total		$ 612	

(1) Ebute, our subsidiary in Nigeria, has received a waiver of default which gives Ebute until December 31, 2010 to cure the breached covenants; however, as this waiver does not extend beyond the Company s current reporting cycle and the probability of curing the default cannot be determined, the debt was classified as current.

None of the subsidiaries that are currently in default is a material subsidiary under AES s corporate debt agreements whose acceleration of debt or bankruptcy would trigger an event of default or permit acceleration under such indebtedness. At December 31, 2009, none of our subsidiaries that are currently in default met the definition of material subsidiary under our recourse senior secured credit facility or other debt agreements. All of the subsidiary guarantors under our recourse secured credit facilities are defined as material subsidiaries under those agreements. The bankruptcy or acceleration of material amounts of debt at these entities would cause a cross default under the recourse secured credit facilities. The subsidiary guarantors include the subsidiaries which own AES Eastern Energy, AES Warrior Run, AES Shady Point and AES Hawaii. However, as a result of additional dispositions of assets, other significant reductions in asset carrying values or other matters in the future that may impact our financial position and results of operations or the financial position or results of the individual subsidiary, it is possible that one or more of these subsidiaries could fall within the definition of a material subsidiary and thereby upon a bankruptcy or acceleration of its non-recourse debt trigger an event of default and possible acceleration of the indebtedness under the AES Parent Company s outstanding debt securities.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

RECOURSE DEBT

The following table summarizes the carrying amount and terms of recourse debt of the Company as of December 31, 2009 and 2008:

RECOURSE DEBT	Interest Rate	Maturity	December 31, 2009	December 31, 2008
			(in millions)	
Senior Unsecured Note	9.50%	2009	$	$ 154
Senior Unsecured Note	9.375%	2010	214	214
Senior Secured Term Loan	LIBOR + 1.75%	2011	200	200
Senior Unsecured Note	8.875%	2011	129	129
Senior Unsecured Note	8.375%	2011	139	124
Second Priority Senior Secured Note	8.75%	2013	690	690
Senior Unsecured Note	7.75%	2014	500	500
Senior Unsecured Note	7.75%	2015	500	500
Senior Unsecured Note	9.75%	2016	535	
Senior Unsecured Note	8.00%	2017	1,500	1,500
Senior Unsecured Note	8.00%	2020	625	625
Term Convertible Trust Securities	6.75%	2029	517	517
Unamortized discounts			(34)	(5)
SUBTOTAL			$ 5,515	$ 5,148
Less: Current maturities			(214)	(154)
Total			$ 5,301	$ 4,994

Recourse debt as of December 31, 2009 is scheduled to reach maturity as set forth in the table below:

December 31,	Annual Maturities (in millions)
2010	$ 214
2011	468
2012	
2013	690
2014	497
Thereafter	3,646
Total recourse debt	$ 5,515

On March 26, 2009, the Parent Company and certain subsidiary guarantors amended the Parent Company s existing senior secured credit facility pursuant to the terms of Amendment No. 1 (Amendment No. 1) to the Fourth Amended and Restated Credit and Reimbursement Agreement, dated as of July 29, 2008 (the senior secured credit facility). The senior secured credit facility previously included a $200 million term loan facility maturing on August 10, 2011 and a $750 million revolving credit facility maturing on June 23, 2010 (the revolving credit facility).

The principal modification set forth in Amendment No. 1 was a one-year extension of $570 million of revolving credit facility commitments from an original maturity date of June 23, 2010 to July 5, 2011. In addition, certain lenders determined that they would increase their commitment under the revolving credit facility by $35 million from March 26, 2009 through July 5, 2011. Accordingly, Amendment No. 1 increased the size of

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

the revolving credit facility from $750 million to $785 million through June 23, 2010. From June 23, 2010 through July 5, 2011, the revolving credit facility size will be $605 million. No modifications were made to the amount or maturity date of the $200 million term loan facility.

The extended commitments from this amendment were subject to new pricing that included an upfront fee of 1.25% for participating in the extensions and an increase in undrawn commitment fees from 50 to 100 basis points. The annual interest rate on the drawn loans was also increased by 200 basis points to LIBOR plus 3.50%. Pricing and all other material terms remain unchanged for the revolving credit facility commitments which have not been extended.

On April 2, 2009 the Parent Company issued $535 million aggregate principal amount of 9.75% senior unsecured notes due 2016 in a private placement. The notes were priced at a discount to yield 11%. Subsequently, the Parent Company allocated a substantial portion of the proceeds to voluntarily reduce the size of its $600 million senior unsecured credit facility. The majority of the letters of credit issued under the facility supported a project under construction in Bulgaria. On October 7, 2009, the Parent Company voluntarily reduced all of the remaining commitments available under the senior unsecured credit facility and terminated the facility agreement. As a result of the termination, the Company recognized a foreign currency transaction gain of $20 million related to the sale of Euros purchased as collateral at the inception of the facility. The outstanding letters of credit under the senior unsecured credit facility were transferred to the senior secured credit facility.

Recourse Debt Covenants and Guarantees

Certain of the Company s obligations under the senior secured credit facility are guaranteed by its direct subsidiaries through which the Company owns its interests in the Shady Point, Hawaii, Warrior Run and Eastern Energy businesses. The Company s obligations under the senior secured credit facility and Second Priority Senior Secured Notes are, subject to certain exceptions, secured by:

(i) all of the capital stock of domestic subsidiaries owned directly by the Company and 65% of the capital stock of certain foreign subsidiaries owned directly or indirectly by the Company; and

(ii) certain intercompany receivables, certain intercompany notes and certain intercompany tax sharing agreements.

The senior secured credit facility is subject to mandatory prepayment under certain circumstances. The net cash proceeds from the sale of a Guarantor or any of its subsidiaries must be applied pro rata to repay the Term Loan using 60% of net cash proceeds, reduced to 50% when and if the parent s recourse debt to cash flow ratio is less than 5:1. The lenders have the option to waive their pro rata redemption. In the case of sales of assets of or equity interests in IPALCO Enterprises (IPALCO) or any of its subsidiaries, any net cash proceeds of the asset sale remaining after application to the Term Loan facility must be used to reduce commitments under the Revolver, unless the supermajority of banks otherwise agree or unless the facilities are rated at least Ba1 from Moody s and AES corporate credit rating from S&P is at least BB .

The senior secured credit facility contains customary covenants and restrictions on the Company s ability to engage in certain activities, including, but not limited to, limitations on other indebtedness, liens, investments and guarantees; limitations on restricted payments such as shareholder dividends and equity repurchases; restrictions on mergers and acquisitions, sales of assets, leases, transactions with affiliates and off-balance sheet or derivative arrangements; and other financial reporting requirements.

The senior secured credit facility also contains financial covenants requiring the Company to maintain certain financial ratios including a cash flow to interest coverage ratio, calculated quarterly, which provides that a

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

minimum ratio of the Company s adjusted operating cash flow to the Company s interest charges related to recourse debt of 1.3× must be maintained at all times and a recourse debt to cash flow ratio, calculated quarterly, which provides that the ratio of the Company s total recourse debt to the Company s adjusted operating cash flow must not exceed a maximum at any time of calculation, or 8.5× at December 31, 2009.

The terms of the Company s Senior Unsecured Notes, senior secured credit facility, and Second Priority Secured Notes contain certain covenants including, without limitation, limitation on the Company s ability to incur liens or enter into sale and leaseback transactions.

TERM CONVERTIBLE TRUST SECURITIES

Between 1999 and 2000, AES Trust III, a wholly owned special purpose business trust, issued approximately 10.35 million of $3.375 Term Convertible Preferred Securities (TECONS) (liquidation value $50) for total proceeds of $517 million and concurrently purchased $517 million of 6.75% Junior Subordinated Convertible Debentures due 2029 (the 6.75% Debentures of the Company). The TECONS are consolidated and classified as long-term recourse debt on the Company s balance sheet.

AES, at its option, can redeem the 6.75% Debentures which would result in the required redemption of the TECONS issued by AES Trust III, currently for $50 per TECON. The TECONS must be redeemed upon maturity of the Junior Subordinated Debentures. The TECONS are convertible into the common stock of AES at each holder s option prior to October 15, 2029 at the rate of 1.4216, representing a conversion price of $35.17 per share.

Dividends on the TECONS are payable quarterly at an annual rate of 6.75%. The Trust is permitted to defer payment of dividends for up to 20 consecutive quarters, provided that the Company has exercised its right to defer interest payments under the corresponding debentures or notes. AES has not exercised the option to defer any dividends at this time. During such deferral periods, dividends on the TECONS would accumulate quarterly and accrue interest, and the Company may not declare or pay dividends on its common stock. All dividends due under the Trust have been paid.

AES Trust III is a VIE under the relevant consolidation accounting guidance. AES s obligations under the Junior Subordinated Debentures and other relevant trust agreements, in aggregate, constitute a full and unconditional guarantee by AES of the TECON Trusts obligations under the trust securities issued by the respective trust. Accordingly, AES consolidates the results of AES Trust III. As of December 31, 2009 and 2008, the sole assets of AES Trust III are the Junior Subordinated Debentures.

11. COMMITMENTS

OPERATING LEASES As of December 31, 2009, the Company was obligated under long-term non-cancelable operating leases, primarily for certain transmission lines, office rental and site leases. Rental expense for lease commitments under these operating leases for the years ended December 31, 2009, 2008 and 2007 was $63 million, $74 million and $64 million, respectively.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The table below sets forth the future minimum lease commitments under these operating leases as of December 31, 2009 for 2010 through 2014 and thereafter:

December 31,	Future Commitments for Operating Leases (in millions)
2010	$ 55
2011	40
2012	40
2013	40
2014	38
Thereafter	264
Total	$ 477

CAPITAL LEASES Several AES subsidiaries lease operating and office equipment and vehicles that are considered capital lease transactions. These capital leases are recognized in Property, Plant and Equipment within Electric generation and distribution assets and primarily relate to transmission lines at our subsidiaries in Brazil. The gross value of the leased assets as of December 31, 2009 and 2008 was $106 million and $95 million, respectively.

The following table summarizes the future minimum lease payments under capital leases together with the present value of the net minimum lease payments as of December 31, 2009 for 2010 through 2014 and thereafter:

December 31,	Future Minimum Lease Payments (in millions)
2010	$ 14
2011	13
2012	12
2013	10
2014	9
Thereafter	146
Total	$ 204
Less: Imputed interest	129
Present value of total minimum lease payments	$ 75

SALE/LEASEBACK In May 1999, a subsidiary of the Company acquired six electric generating stations from New York State Electric and Gas (NYSEG). Concurrently, the subsidiary sold two of the plants to an unrelated third party for $666 million and simultaneously entered into a leasing arrangement with the unrelated party. This transaction has been accounted for as a sale/leaseback with operating lease treatment. In

May 2007, the subsidiary purchased a portion of the lessor s interest in a trust estate that holds the leased plants. Future minimum lease commitments under the lease agreement are reduced by the subsidiary s interest in the plants. Rental expense was $34 million, $34 million and $42 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following table summarizes the future minimum lease commitments under the sale/leaseback arrangement as of December 31, 2009 for 2010 through 2014 and thereafter:

December 31,	Future Minimum Lease Commitments (in millions)
2010	$ 41
2011	43
2012	44
2013	46
2014	47
Thereafter	483
Total	$ 704

CONTRACTS Operating subsidiaries of the Company have entered into contracts for the purchase of electricity from third parties that primarily include energy auction agreements at our Brazil subsidiaries with extended terms from 2010 through 2042. Purchases in the years ended December 31, 2009, 2008 and 2007 were approximately $2.1 billion, $1.5 billion and $2.2 billion, respectively.

The table below sets forth the future commitments under these electricity purchase contracts at December 31, 2009 for 2010 through 2014 and thereafter:

December 31,	Future Commitments for Electricity Purchase Contracts (in millions)
2010	$ 2,403
2011	2,773
2012	3,021
2013	2,886
2014	2,717
Thereafter	41,398
Total	$ 55,198

Operating subsidiaries of the Company have entered into various long-term contracts for the purchase of fuel subject to termination only in certain limited circumstances. Purchases in the years ended December 31, 2009, 2008 and 2007 were $1.4 billion, $1.3 billion and $1.3 billion, respectively.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The table below sets forth the future commitments under these fuel contracts as of December 31, 2009 for 2010 through 2014 and thereafter:

December 31,	Future Commitments for Fuel Contracts (in millions)
2010	$ 1,681
2011	1,022
2012	791
2013	692
2014	593
Thereafter	5,369
Total	$ 10,148

The Company s subsidiaries have entered into other various long-term contracts. These contracts are mainly for construction projects, service and maintenance, transmission of electricity and other operation services. Payments under these contracts for the years ended December 31, 2009, 2008 and 2007 were $2.8 billion, $1.9 billion and $840 million, respectively.

The table below sets forth the future commitments under these other purchase contracts as of December 31, 2009 for 2010 through 2014 and thereafter:

December 31,	Future Commitments for Other Purchase Contracts (in millions)
2010	$ 2,217
2011	1,356
2012	1,144
2013	881
2014	867
Thereafter	11,414
Total	$ 17,879

12. CONTINGENCIES

ENVIRONMENTAL

The Company reviews its obligations as they relate to compliance with environmental laws, including site restoration and remediation. As of December 31, 2009, the Company has recognized liabilities of $28 million for projected environmental remediation costs. Due to the uncertainties associated with environmental assessment and remediation activities, future costs of compliance or remediation could be higher or lower than the amount currently accrued. Based on currently available information and analysis, the Company believes that it is reasonably possible that costs associated with such liabilities or as yet unknown liabilities may exceed current reserves in amounts that could be material but cannot be estimated as of December 31, 2009.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The Company faces certain risks and uncertainties related to numerous environmental laws and regulations, including potential greenhouse gas (GHG) legislation or regulations, and actual or potential laws and regulations pertaining to water discharges, waste management (including disposal of coal combustion by-products), and certain air emissions, such as SO_2, NO_x, particulate matter and mercury. Such risks and uncertainties include risks and uncertainties related to increased capital expenditures or other compliance costs which could have a material adverse effect on certain of our U.S. or international subsidiaries and our consolidated results of operations.

To date, the primary regulation of GHG emissions affecting the Company s U.S. plants has been through the Regional Greenhouse Gas Initiative (RGGI). Under RGGI, ten Northeastern States have coordinated to establish rules that require reductions in CO_2 emissions from power plant operations within those states through a cap-and-trade program. States in which our subsidiaries have generating facilities include Connecticut, Maryland, New York and New Jersey. Under RGGI, power plants must acquire one carbon allowance through auction or in the emission trading markets for each ton of CO_2 emitted, as noted in Item 1. Business-Regulatory Matters-Environmental and Land Use Regulations of this Form 10-K.

The primary international agreement concerning GHG emissions is the Kyoto Protocol which became effective on February 16, 2005 and requires the industrialized countries that have ratified it to significantly reduce their GHG emissions. The vast majority of the developing countries which have ratified the Kyoto Protocol have no GHG reduction requirements. Many of the countries in which the Company s subsidiaries operate have no reduction obligations under the Kyoto Protocol. In addition, of the 29 countries in which Company s subsidiaries operate in, all but one the United States (including Puerto Rico) have ratified the Kyoto Protocol.

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). The European Union has announced that it intends to keep the European Union Emissions Trading System (EU ETS) in place after the potential expiration of the Kyoto Protocol in 2012. 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. 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 Energía 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 will prevail, or that the cost and administrative burden associated with any such dispute will not be significant.

In 2009, a key development in the area of GHG legislation was the passage of H.R. 2454, The American Clean Energy and Security Act of 2009 (ACESA) by the U.S. House of Representatives on June 26, 2009. The full U.S. Senate may consider similar legislation in 2010. ACESA 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;

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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 will 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; and

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;

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 AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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.

Our subsidiaries conduct business in a number of countries that have ratified the Kyoto Protocol, an international agreement concerning GHG emissions. The Kyoto Protocol is currently expected to expire at the end of 2012. 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.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

There is substantial uncertainty with respect to whether U.S. federal GHG legislation will be enacted into law, whether the EPA will regulate GHG emissions, and whether a new international agreement to succeed the Kyoto Protocol will be reached, and there is additional uncertainty regarding the final provisions and implementation of any potential U.S. federal GHG legislation, any EPA rules regulating GHG emissions and any international agreement to succeed the Kyoto Protocol. In light of these uncertainties, the Company cannot accurately predict the impact on its consolidated results of operations or financial condition from potential U.S. federal GHG legislation, EPA regulation of GHG emissions or any new international agreement on such emissions, or make a reasonable estimate of the potential costs to the Company associated with any such legislation, regulation or international agreement; however, the impact from any such legislation, regulation or international agreement could have a material adverse effect on certain of our U.S. or international subsidiaries and on the Company and its consolidated results of operations.

In additional to the risks and uncertainties related to potential GHG regulations or legislation, the Company faces risk and uncertainties related to regulations or legislation concerning other types of air emissions, such as SO_2, NO_x, particulate matter (PM) and mercury. In the U.S., the Clean Air Act (CAA) and various state laws and regulations regulate emissions of air pollutants, including SO_2, NO_x, 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 EPA and other petitioners, the Court issued an opinion and remanded the rule to EPA without vacatur to enable EPA to remedy CAIR s flaws in accordance with the Court s July opinion. 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 date 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

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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 NO_x 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 NO_x 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 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 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. Only 13 states met this deadline. EPA has yet to approve any state s Regional Haze state implementation plan. The statute requires compliance within 5 years after EPA approves the relevant SIP.

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 NOx, 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 PM. 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 AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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.

The Company also faces certain risks and uncertainties related to environmental laws and regulations pertaining to 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 U.S. 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 the 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 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.

The Company also faces certain risks and uncertainties related to environmental laws and regulations pertaining to 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

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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.

GUARANTEES, LETTERS OF CREDIT

In connection with certain project financing, acquisition, power purchase, and other agreements, AES has expressly undertaken limited obligations and commitments, most of which will only be effective or will be terminated upon the occurrence of future events. In the normal course of business, AES and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees and letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise achieved by a subsidiary on a stand-alone basis, thereby facilitating the availability of sufficient credit to accomplish the subsidiaries intended business purposes. In addition to the contingent obligations of the Parent Company identified in the table below, the Company s subsidiaries had letters of credit outstanding to support various contingent obligations. At December 31, 2009, these letters of credit at our consolidated subsidiaries totaled approximately $1.8 billion.

The following table summarizes the Parent Company s contingent contractual obligations as of December 31, 2009:

Contingent contractual obligations	Amount	Number of Agreements	Maximum Exposure Range for Each Agreement
	(in millions)		(in millions)
Guarantees	$ 410	31	<$ 1 - $53
Letters of credit under the senior secured credit facility	204	26	<$ 1 - $120
Total	$ 614	57	

Most of the contingent obligations primarily relate to future performance commitments which the Company or its subsidiaries expect to fulfill within the normal course of business. Amounts presented in the above table represent the Parent Company s current undiscounted exposure to guarantees and the range of maximum undiscounted potential exposure to the Parent Company as of December 31, 2009. Guarantee termination provisions vary from less than one year to greater than 20 years. Some result from the end of a contract period, assignment, asset sale, and change in credit rating or elapsed time. The amounts above include obligations made by the Parent Company for the direct benefit of the lenders associated with the non-recourse debt of subsidiaries of $49 million.

The risks associated with these obligations include change of control, construction cost overruns, political risk, tax indemnities, spot market power prices, supplier support and liquidated damages under power purchase

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

agreements for projects in development, under construction and operating. While the Company does not expect to be required to fund any material amounts under these contingent contractual obligations during 2009 or beyond that are not recognized on the Consolidated Balance Sheet, many of the events which would give rise to such an obligation are beyond the Parent Company s control. There can be no assurance that the Parent Company would have adequate sources of liquidity to fund its obligations under these contingent contractual obligations if it were required to make substantial payments thereunder.

During 2009, the Company paid letter of credit fees ranging from 1.63% to 13.34% per annum on the outstanding amounts of letters of credit.

LITIGATION

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. 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.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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.

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.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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 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

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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.

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

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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 Empresa Electrica Campiche s (EEC) 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. 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.

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

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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.

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

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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 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.

13. BENEFIT PLANS

DEFINED CONTRIBUTION PLAN The Company sponsors one defined contribution plan, qualified under section 401 of the Internal Revenue Code. All U.S. employees of the Company are eligible to participate in the plan except for those employees who are not covered by their collective bargaining agreement. The plan provides for Company matching contributions in Company stock, other Company contributions at the discretion of the Compensation Committee of the Board of Directors in Company stock and discretionary tax deferred contributions from the participants. Participants are fully vested in their own contributions and the Company s matching contributions. Participants vest in other Company contributions ratably over a five-year period ending on the fifth anniversary of their hire date. Company contributions to the plans were approximately $22 million, $21 million, and $22 million for the years ended December 31, 2009, 2008, and 2007, respectively.

DEFINED BENEFIT PLANS Certain of the Company s subsidiaries have defined benefit pension plans covering substantially all of their respective employees. Pension benefits are based on years of credited service, age of the participant and average earnings. Of the 25 defined benefit plans, three are at U.S. subsidiaries and the remaining plans are at foreign subsidiaries.

AES adopted the measurement date provisions of the pension accounting guidance, which require a year-end measurement date of plan assets and obligations for all defined benefit plans, for the fiscal year ended December 31, 2008 and accordingly, recognized a cumulative adjustment of $1 million to retained earnings as of December 31, 2008.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following table reconciles the Company s funded status, both domestic and foreign, as of December 31, 2009 and 2008:

	December 31,			
	2009		2008	
	U.S.	Foreign	U.S.	Foreign
	(in millions)			
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Benefit obligation at beginning of year	$ 557	$ 3,498	$ 513	$ 4,358
Adjustments due to adoption of measurement date provisions			3	1
Service cost	7	13	6	11
Interest cost	34	459	32	453
Employee contributions		19		20
Plan amendments			10	
Plan settlements			(1)	
Benefits paid	(30)	(366)	(32)	(377)
Actuarial loss (gain)	11	304	26	138
Effect of foreign currency exchange rate change		1,211		(1,106)
Benefit obligation as of December 31	$ 579	$ 5,138	$ 557	$ 3,498
CHANGE IN PLAN ASSETS:				
Fair value of plan assets at beginning of year	327	2,752	430	3,587
Actual return on plan assets	74	489	(129)	268
Employer contributions	21	188	59	138
Employee contributions		19		20
Plan settlements			(1)	
Benefits paid	(30)	(366)	(32)	(377)
Effect of foreign currency exchange rate change		963		(884)
Fair value of plan assets as of December 31	$ 392	$ 4,045	$ 327	$ 2,752
RECONCILIATION OF FUNDED STATUS				
Funded status as of December 31	$ (187)	$ (1,093)	$ (230)	$ (746)

The following table summarizes the amounts recognized on the Consolidated Balance Sheets, both domestic and foreign, as of December 31, 2009 and 2008:

	December 31,			
	2009		2008	
	U.S.	Foreign	U.S.	Foreign
	(in millions)			
AMOUNTS RECOGNIZED ON THE CONSOLIDATED BALANCE SHEETS				
Noncurrent assets	$	$ 32	$	$ 22

Accrued benefit liability current		(4)		(3)
Accrued benefit liability long-term	(187)	(1,121)	(230)	(765)
Net amount recognized at end of year	$ (187)	$ (1,093)	$ (230)	$ (746)

215

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following table summarizes the Company s accumulated benefit obligation, both domestic and foreign, as of December 31, 2009 and 2008:

	December 31, 2009		2008	
	U.S.	Foreign	U.S.	Foreign
	(in millions)			
Accumulated Benefit Obligation	$ 562	$ 5,098	$ 541	$ 3,335
Information for pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	$ 579	$ 4,887	$ 557	$ 3,336
Accumulated benefit obligation	562	4,855	541	3,179
Fair value of plan assets	392	3,765	327	2,570
Information for pension plans with a projected benefit obligation in excess of plan assets:				
Projected benefit obligation	$ 579	$ 4,892	$ 557	$ 3,339
Fair value of plan assets	392	3,766	327	2,571

The table below demonstrates the significant weighted average assumptions used in the calculation of benefit obligation and net periodic benefit cost, both domestic and foreign, as of December 31, 2009 and 2008:

	December 31, 2009		2008	
	U.S.	Foreign	U.S.	Foreign
Benefit Obligation:				
Discount rates	5.93%	10.56%	6.26%	11.78%
Rates of compensation increase	4.00%	6.00%	4.75%	5.97%
Periodic Benefit Cost:				
Discount rate	6.26%	11.78%	6.48%	11.25%
Expected long-term rate of return on plan assets	8.00%	11.99%	7.77%	12.31%
Rate of compensation increase	4.75%	5.97%	4.75%	6.93%

A subsidiary of the Company has a defined benefit obligation of $549 million and $528 million as of December 31, 2009 and 2008, respectively, and uses salary bands to determine future benefit costs rather than a rate of compensation increases. Rates of compensation increases in the table above do not include amounts related to this specific defined benefit plan.

The Company establishes its estimated long-term return on plan assets considering various factors, which include the targeted asset allocation percentages, historic returns and expected future returns.

The measurement of pension obligations, costs and liabilities is dependent on a variety of assumptions. These assumptions include estimates of the present value of projected future pension payments to all plan participants, taking into consideration the likelihood of potential future events such as salary increases and demographic experience. These assumptions may have an effect on the amount and timing of future contributions.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The assumptions used in developing the required estimates include the following key factors:

- discount rates;
- salary growth;
- retirement rates;
- inflation;
- expected return on plan assets; and
- mortality rates.

The effects of actual results differing from the Company s assumptions are accumulated and amortized over future periods and, therefore, generally affect our recognized expense in such future periods.

Sensitivity of our pension funded status and stockholders equity to the indicated increase or decrease in the discount rate and long-term rate of return on plan assets assumptions is shown below. Note that these sensitivities may be asymmetric and are specific to the base conditions at year-end 2009. They also may not be additive, so the impact of changing multiple factors simultaneously cannot be calculated by combining the individual sensitivities shown. The December 31, 2009 funded status is affected by the December 31, 2009 assumptions. Pension expense for 2009 is affected by the December 31, 2008 assumptions. The impact on pension expense from a one percentage point change in these assumptions is shown in the table below (in millions):

Increase of 1% in the discount rate	$ (14)
Decrease of 1% in the discount rate	$ 22
Increase of 1% in the long-term rate of return on plan assets	$ (34)
Decrease of 1% in the long-term rate of return on plan assets	$ 34

The following table summarizes the components of the net periodic benefit cost, both domestic and foreign, for the years ended December 31, 2009 through 2007:

	December 31,					
	2009		2008		2007	
Components of Net Periodic Benefit Cost:	**U.S.**	**Foreign**	**U.S.**	**Foreign**	**U.S.**	**Foreign**
			(in millions)			

Service cost	$ 7	$ 13	$ 6	$ 11	$ 7	$ 9
Interest cost	34	459	32	453	30	393
Expected return on plan assets	(26)	(374)	(34)	(412)	(33)	(333)
Amortization of initial net asset		(2)		(3)		(3)
Amortization of prior service cost	4		3		3	
Amortization of net loss	16	7	1	2	6	2
Curtailment gain recognized						(3)
Settlement gain recognized			1			(6)
Total pension cost	$ 35	$ 103	$ 9	$ 51	$ 13	$ 59

217

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following table summarizes the amounts reflected in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheet as of December 31, 2009 that have not yet been recognized as components of net periodic benefit cost:

	December 31, 2009			
	Accumulated Other Comprehensive Loss		Amounts expected to be reclassified to earnings in next fiscal year	
	U.S.	Foreign	U.S.	Foreign
	(in millions)			
Initial net transition asset	$	$ 1	$	$ 1
Prior service cost		(2)		
Unrecognized net actuarial gain (loss)	1	(722)		(14)
Total	$ 1	$ (723)	$	$ (13)

The following table summarizes the Company s target allocation for 2009 and pension plan asset allocation, both domestic and foreign, as of December 31, 2009 and 2008:

			Percentage of Plan Assets as of December 31,			
	Target Allocations		2009		2008	
Asset Category	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign
Equity securities	27% - 74%	15% - 32%	57.23%	22.22%	54.57%	22.24%
Debt securities	26% - 54%	59% - 85%	34.50%	73.34%	37.08%	72.30%
Real estate	0% - 9%	0% - 4%	0.00%	2.07%	1.91%	1.23%
Other	0% - 9%	0% - 4%	8.27%	2.37%	6.44%	4.23%
Total pension assets			100.00%	100.00%	100.00%	100.00%

The U.S. plans seek to achieve the following long-term investment objectives:

- Maintenance of sufficient income and liquidity to pay retirement benefits and other lump sum payments;
- Long-term rate of return in excess of the annualized inflation rate;
- Long-term rate of return (net of relevant fees that meet or exceed the assumed actuarial rate);

Long-term competitive rate of return on investments, net of expenses, that is equal to or exceeds various benchmark rates.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The asset allocation is reviewed periodically to determine a suitable asset allocation which seeks to control risk through portfolio diversification and takes into account, among other possible factors, the above-stated objectives, in conjunction with current funding levels, cash flow conditions and economic and industry trends. The following table summaries the Company s U.S. plan assets by category of investment and level within the fair value hierarchy as of December 31, 2009:

U.S. Plans	December 31, 2009	Quoted Market Prices in Active Market for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(in millions)		
Equity securities:				
Common stock	$ 220	$ 189	$ 31	$
Mutual funds	3	3		
Debt securities:				
Government debt securities	48	48		
Corporate debt securities	71	71		
Mutual funds[(1)]	2	2		
Other debt securities	15	15		
Other:				
Cash and cash equivalents	17	17		
Other investments	16		16	
Total plan assets	$ 392	$ 345	$ 47	$

(1) Mutual funds categorized as debt securities consist of mutual funds for which debt securities are the primary underlying investment.

The investment strategy of the foreign plans seeks to maximize return on investment while minimizing risk. Our assumed asset allocation uses a lower exposure to equities to closely match market conditions and near term forecasts. The following table summaries the Company s foreign plan assets by category of investment and level within the fair value hierarchy as of December 31, 2009:

Foreign Plans	December 31, 2009	Quoted Market Prices in Active Market for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(in millions)		
Equity securities:				
Common stock	$ 21	$ 21	$	$
Mutual funds	472	472		
Private equity[(1)]	406			406
Debt securities:				
Certificates of deposit	7		7	

Unsecured debentures	14		14	
Government debt securities	206		206	
Mutual funds[2]	2,734	2,734		
Other debt securities	5		5	
Real estate:				
Real estate[1]	84			84
Other:				
Cash and cash equivalents	22	20	2	
Participant loans[3]	74			74
Total plan assets	$ 4,045	$ 3,247	$ 234	$ 564

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

(1) Plan assets of our Brazilian subsidiaries are invested in private equities and commercial real estate through the plan administrator in Brazil. The fair value of these assets is determined using the income approach through annual appraisals based on a discounted cash flow analysis.
(2) Mutual funds categorized as debt securities consist of mutual funds for which debt securities are the primary underlying investment.
(3) Loans to participants are stated at cost, which approximates fair value.

The following table presents a reconciliation of all plan assets measured at fair value using significant unobservable inputs (Level 3) for the year ended December 31, 2009:

	Level 3 (in millions)
Balance at January 1, 2009	$ 380
Actual return on plan assets:	
Returns relating to assets still held at reporting date	46
Purchases, sales, issuances and settlements	1
Change due to exchange rate changes	137
Balance at December 31, 2009	$ 564

The following table summarizes the scheduled cash flows for U.S. and foreign expected employer contributions and expected future benefit payments, both domestic and foreign:

	U.S.	Foreign
	(in millions)	
Expected employer contribution in 2010	$ 27	$ 152
Expected benefit payments for fiscal year ending:		
2010	32	450
2011	32	403
2012	33	403
2013	34	404
2014	36	406
2015 2019	201	2,024

14. EQUITY

STOCK PURCHASE AGREEMENT

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.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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 15% fully diluted ownership 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.

STOCK REPURCHASE

On August 7, 2008, the Company s Board of Directors approved a share repurchase plan for up to $400 million of its outstanding common stock. The Board authorization permitted the Company to repurchase shares over a six month period ending February 7, 2009. Shares of common stock repurchased under this plan through December 31, 2008 totaled 10,691,267 at a total cost of $143 million plus commissions of $0.3 million (average of $13.41 per share including commissions). The shares of stock repurchased have been classified as treasury stock and accounted for using the cost method. A total of 9,534,580 and 10,691,267 shares were held in treasury stock at December 31, 2009 and 2008, respectively. At December 31, 2007, there were no shares of common stock held in treasury stock. No shares of common stock were repurchased subsequent to December 31, 2008 and the Board authorization of the plan expired on February 7, 2009. The Company did not retire any shares of treasury stock during the years ended December 31, 2009 or 2008.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

COMPREHENSIVE INCOME

The components of comprehensive income for the years ended December 31, 2009, 2008 and 2007 were as follows:

	2009	December 31, 2008 (in millions)	2007
Net income	$ 1,755	$ 2,032	$ 357
Change in fair value of available-for-sale securities, net of income tax (expense) benefit of $(4), $ and $(3), respectively	6		3
Foreign currency translation adjustments, net of income tax (expense) benefit of $(78), $53 and $(33), respectively	742	(1,052)	643
Derivative activity:			
Reclassification to earnings, net of income tax (expense) benefit of $(41), $(19) and $(38), respectively	(141)	90	(50)
Change in derivative fair value, net of income tax (expense) benefit of $34 $(29) and $109, respectively	214	(158)	(84)
Total change in fair value of derivatives	73	(68)	(134)
Change in unfunded pension obligation, net of income tax benefit of $69, $77 and $, respectively	(139)	(149)	(3)
Other comprehensive (loss) income	682	(1,269)	509
Comprehensive income	2,437	763	866
Less: Comprehensive income attributable to noncontrolling interests[(1)]	(1,485)	(169)	(745)
Comprehensive income attributable to The AES Corporation	$ 952	$ 594	$ 121

(1) Reflects the income (loss) attributed to noncontrolling interests in the form of common securities and dividends on preferred stock of subsidiary.

The following table summarizes the balances comprising accumulated other comprehensive loss, net of tax, as of December 31, 2009 and 2008:

	December 31, 2009 (in millions)	2008
Foreign currency translation adjustment	$ 2,312	$ 2,584
Unrealized derivative losses	224	263
Unfunded pension obligation	194	171
Securities available for sale	(6)	

Total	$ 2,724	$ 3,018

222

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

15. SEGMENT AND GEOGRAPHIC INFORMATION

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 segment reporting structure uses the Company s management reporting structure as its foundation to reflect 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 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 (Climate Solutions) are managed within the region in which they are located. Key climate solutions initiatives include investments in GHG initiatives, projects to create emissions offsets for the voluntary U.S. market and projects that produce certified emission reduction credits (CERs). Despite the management of AES Wind Generation by the North America region and Climate Solutions within the regions, AES Wind Generation and Climate Solutions 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. 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 or gross margin. None of these operating segments are currently material to our 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.

The Company uses Adjusted Gross Margin, a non-GAAP measure, to evaluate the performance of its segments. Adjusted Gross Margin is defined by the Company as: Gross Margin plus depreciation and amortization less general and administrative expenses. In 2009, the Company changed the segment performance measures disclosed to align with how management internally reviews the results and assesses the performance of the business. Accordingly, previously reported segment information has been revised to reflect our new measure of segment performance, Adjusted Gross Margin, to conform to current year presentation.

Segment revenue includes inter-segment sales related to the transfer of electricity from generation plants to utilities within Latin America. No inter-segment revenue relationships exist between other segments. Corporate allocations include certain management fees and self insurance activity which are reflected within segment

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

Adjusted Gross Margin. All intra-segment activity has been eliminated with respect to revenue and Adjusted Gross Margin within the segment. Inter-segment activity has been eliminated within the total consolidated results. All balance sheet information for businesses that were discontinued or classified as held for sale as of December 31, 2009 is segregated and is shown in the line Discontinued Businesses in the accompanying segment tables.

The tables below present the breakdown of business segment balance sheet and income statement data as of and for the years ended December 31, 2009 through 2007:

	Total Revenue			Intersegment			External Revenue		
	2009	2008	2007	2009	2008 (in millions)	2007	2009	2008	2007
Revenue									
Latin America Generation	$ 3,651	$ 4,468	$ 3,515	$ (864)	$ (991)	$ (886)	$ 2,787	$ 3,477	$ 2,629
Latin America Utilities	6,092	5,907	5,168			(17)	6,092	5,907	5,151
North America Generation	1,940	2,234	2,169				1,940	2,234	2,169
North America Utilities	1,068	1,079	1,052				1,068	1,079	1,052
Europe Generation	720	1,096	909	(1)			719	1,096	909
Asia Generation	643	553	315				643	553	315
Corp/Other & eliminations	5	21	(114)	865	991	903	870	1,012	789
Total Revenue	$ 14,119	$ 15,358	$ 13,014	$	$	$	$ 14,119	$ 15,358	$ 13,014

	Total Adjusted Gross Margin			Intersegment			External Adjusted Gross Margin		
	2009	2008	2007	2009	2008 (in millions)	2007	2009	2008	2007
Adjusted Gross Margin									
Latin America Generation	$ 1,528	$ 1,557	$ 1,125	$ (852)	$ (978)	$ (855)	$ 676	$ 579	$ 270
Latin America Utilities	1,130	1,102	1,046	865	991	870	1,995	2,093	1,916
North America Generation	658	836	880	(3)	17	17	655	853	897
North America Utilities	401	419	453	2	2	2	403	421	455
Europe Generation	217	284	279		2	4	217	286	283
Asia Generation	220	90	92	7	4	4	227	94	96
Corp/Other & eliminations	1	(64)	(66)	(19)	(38)	(42)	(18)	(102)	(108)
Reconciliation to Income from Continuing Operations before Taxes									
Depreciation and amortization							(1,005)	(963)	(889)
Interest expense							(1,515)	(1,803)	(1,755)
Interest income							348	519	489
Other expense							(111)	(161)	(253)
Other income							466	377	358
Gain on sale of investments							131	909	
(Loss) gain on sale of subsidiary stock								(31)	134
Goodwill impairment expense							(122)		
Asset impairment expense							(25)	(175)	(408)

Foreign currency transaction gain (loss) on net monetary position	33	(184)	29
Other non-operating expense	(12)	(15)	(57)
Income from continuing operations before taxes and equity in earnings of affiliates	$ 2,343	$ 2,697	$ 1,457

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

	Total Assets			Depreciation and Amortization			Capital Expenditures		
	2009	2008	2007	2009	2008	2007	2009	2008	2007
	(in millions)								
Latin America Generation	$ 9,802	$ 8,217	$ 7,662	$ 183	$ 168	$ 169	$ 951	$ 886	$ 393
Latin America Utilities	9,233	7,124	8,779	220	221	199	413	437	394
North America Generation	6,226	6,444	6,282	208	197	191	98	134	165
North America Utilities	3,035	3,092	2,836	157	152	142	116	117	202
Europe Generation	2,878	2,653	2,544	51	48	60	166	423	654
Asia Generation	2,506	2,443	1,387	62	49	33	68	143	54
Discontinued businesses	590	764	1,244	19	28	37	4	13	55
Corp/Other & eliminations	5,265	4,069	3,719	149	138	111	722	744	543
Total	$ 39,535	$ 34,806	$ 34,453	$ 1,049	$ 1,001	$ 942	$ 2,538	$ 2,897	$ 2,460

	Investment in and Advances to Affiliates			Equity in Earnings (Loss)		
	2009	2008	2007	2009	2008	2007
	(in millions)					
Latin America Generation	$ 129	$ 81	$ 67	$ 30	$ 9	$ 17
Latin America Utilities						
North America Generation	3	2		(2)	(2)	
North America Utilities		1	1			
Europe Generation	308	232	200	50	28	11
Asia Generation	390	371	427	28	12	43
Discontinued businesses						
Corp/Other & eliminations	327	214	35	(14)	(14)	5
Total	$ 1,157	$ 901	$ 730	$ 92	$ 33	$ 76

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The table below presents information, by country, about the Company s consolidated operations for each of the years ended December 31, 2009 through 2007 and as of December 31, 2009 and 2008, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

	Revenue 2009	Revenue 2008	Revenue 2007	Property, Plant & Equipment, net 2009	Property, Plant & Equipment, net 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.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

16. SHARE-BASED COMPENSATION

STOCK OPTIONS AES grants options to purchase shares of common stock under stock option plans. Under the terms of the plans, the Company may issue options to purchase shares of the Company s common stock at a price equal to 100% of the market price at the date the option is granted. Stock options are generally granted based upon a percentage of an employee s base salary. Stock options issued under these plans in 2009, 2008 and 2007 have a three-year vesting schedule and vest in one-third increments over the three-year period. The stock options have a contractual term of ten years. At December 31, 2009, approximately 16 million shares were remaining for award under the plans. In all circumstances, stock options granted by AES do not entitle the holder the right, or obligate AES, to settle the stock option in cash or other assets of AES.

The weighted average fair value of each option grant has been estimated, as of the grant date, using the Black-Scholes option-pricing model with the following weighted average assumptions:

	December 31,		
	2009	**2008**	**2007**
Expected volatility	66%	37%	29%
Expected annual dividend yield	%	%	%
Expected option term (years)	6	6	6
Risk-free interest rate	2.01%	3.04%	4.67%

The Company exclusively relies on implied volatility as the expected volatility to determine the fair value using the Black-Scholes option-pricing model. The implied volatility may be exclusively relied upon due to the following factors:

- The Company utilizes a valuation model that is based on a constant volatility assumption to value its employee share options;
- The implied volatility is derived from options to purchase AES common stock that are actively traded;
- The market prices of both the traded options and the underlying share are measured at a similar point in time to each other and on a date reasonably close to the grant date of the employee share options;
- The traded options have exercise prices that are both near-the-money and close to the exercise price of the employee share options; and
- The remaining maturities of the traded options on which the estimate is based are at least one year.

Pursuant to share-based compensation accounting guidance, the Company used a simplified method to determine the expected term based on the average of the original contractual term and the pro rata vesting period. This simplified method was used for stock options granted during the years ended December 31, 2009, 2008, and 2007. This is appropriate given a lack of relevant stock option exercise data. This simplified method may be used as the Company s stock options have the following characteristics:

The stock options are granted at-the-money;

Exercisability is conditional only on performing service through the vesting date;

If an employee terminates service prior to vesting, the employee forfeits the stock options;

If an employee terminates service after vesting, the employee has a limited time to exercise the stock option; and

The stock option is nonhedgeable and not transferable.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The Company does not discount the grant date fair values determined to estimate post-vesting restrictions. Post-vesting restrictions include black-out periods when the employee is not able to exercise stock options based on their potential knowledge of information prior to the release of that information to the public.

Using the above assumptions, the weighted average fair value of each stock option granted was $4.08, $7.65 and $8.49, for the years ended December 31, 2009, 2008, and 2007, respectively.

The following table summarizes the components of stock-based compensation related to employee stock options recognized in the Company s financial statements:

	2009	December 31, 2008 (in millions)	2007
Pre-tax compensation expense	$ 10	$ 12	$ 15
Tax benefit	(3)	(3)	(4)
Stock options expense, net of tax	$ 7	$ 9	$ 11
Total intrinsic value of options exercised	$ 3	$ 9	$ 41
Total fair value of options vested	13	13	14
Cash received from the exercise of stock options	6	17	50
Windfall tax benefits realized from the exercised stock options		1	2

There was no cash used to settle stock options or compensation cost capitalized as part of the cost of an asset for the years ended December 31, 2009, 2008 and 2007. As of December 31, 2009, $10 million of total unrecognized compensation cost related to stock options is expected to be recognized over a weighted average period of 1.5 years. There were no modifications to stock option awards during the year ended December 31, 2009.

A summary of the option activity for year ended December 31, 2009 follows (number of options in thousands, dollars in millions except per option amounts):

	Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value
Outstanding at December 31, 2008	24,308	$ 18.52		
Exercised year to date	(693)	8.44		
Forfeited and expired year to date	(2,924)	20.16		
Granted year to date	1,681	6.70		
Outstanding at December 31, 2009	22,372	$ 17.59	3.6	$ 34
Vested and expected to vest at December 31, 2009	21,681	$ 17.70	3.5	$ 32

Eligible for exercise at December 31, 2009	19,173	$ 18.30	2.7	$ 23

The aggregate intrinsic value in the table above represents the total pre-tax intrinsic value (the difference between the Company s closing stock price on the last trading day of the fourth quarter of 2009 and the exercise price, multiplied by the number of in-the-money options) that would have been received by the option holders had all option holders exercised their options on December 31, 2009. The amount of the aggregate intrinsic value will change based on the fair market value of the Company s stock.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The Company initially recognizes compensation cost on the estimated number of instruments for which the requisite service is expected to be rendered. In 2009, AES has estimated a forfeiture rate of 19.42% and 11.62% for stock options granted in 2009 to non-officer employees and officer employees of AES, respectively. Those estimates shall be revised if subsequent information indicates that the actual number of instruments forfeited is likely to differ from previous estimates. Based on the estimated forfeiture rates, the Company expects to expense $6 million on a straight-line basis over a three year period (approximately $2 million per year) related to stock options granted during the year ended December 31, 2009.

RESTRICTED STOCK

Restricted Stock Units Without Market Conditions The Company issues restricted stock units (RSUs) without market conditions under its long-term compensation plan. The RSUs are generally granted based upon a percentage of the participant s base salary. The units have a three-year vesting schedule and vest in one-third increments over the three-year period. The units are then required to be held for an additional two years before they can be redeemed for shares, and thus become transferable.

For the years ended December 31, 2009, 2008, and 2007, RSUs issued without a market condition had a grant date fair value equal to the closing price of the Company s stock on the grant date. The Company does not discount the grant date fair values to reflect any post-vesting restrictions. RSUs without a market condition granted to non-executive employees during the years ended December 31, 2009, 2008, and 2007 had grant date fair values per RSU of $6.71, $18.87 and $22.28, respectively. The total grant date fair value of RSUs granted without a market condition was $12 million during the year ended December 31, 2009.

The following table summarizes the components of the Company s stock-based compensation related to its employee RSUs issued without market conditions recognized in the Company s financial statements:

		December 31,	
	2009	2008	2007
		(in millions)	
RSU expense before income tax	$ 11	$ 10	$ 10
Tax benefit	(3)	(2)	(3)
RSU expense, net of tax	$ 8	$ 8	$ 7
Total value of RSUs converted[1]	$ 7	$	$
Total fair value of RSUs vested	$ 12	$ 10	$ 10

(1) Amount represents fair market value on the date of conversion.

There was no cash used to settle RSUs or compensation cost capitalized as part of the cost of an asset for the years ended December 31, 2009, 2008 and 2007. As of December 31, 2009, $13 million of total unrecognized compensation cost related to RSUs without a market condition is expected to be recognized over a weighted average period of approximately 1.6 years. There were no modifications to RSU awards during the year ended December 31, 2009.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

A summary of the RSUs activity for the year ended December 31, 2009 follows (number of RSUs in thousands):

	RSUs	Weighted Average Grant-date Fair Values	Weighted Average Remaining Vesting Term
Nonvested at December 31, 2008	1,535	$ 19.73	
Vested year to date	(619)	19.66	
Forfeited and expired year to date	(262)	14.53	
Granted year to date	1,817	6.71	
Nonvested at December 31, 2009	2,471	$ 10.73	1.7
Vested at December 31, 2009	1,810	$ 18.59	
Vested and expected to vest at December 31, 2009	3,890	$ 13.97	

The table below summarizes the RSUs without a market condition that vested and were converted during the years ended December 31, 2009, 2008 and 2007 (number of RSUs in thousands):

	December 31, 2009	2008	2007
RSUs vested during the year	619	597	714
RSUs converted during the year	772[(1)]	59[(1)]	

(1) Net of shares withheld for taxes of 238,000 in the year ended December 31, 2009. No shares were withheld for taxes during the year ended December 31, 2008.

Restricted Stock Units With Market Conditions Restricted stock units issued to officers of the Company have a three-year vesting schedule and include a market condition to vest. Vesting will occur if the applicable continued employment conditions are satisfied and the Total Stockholder Return (TSR) on AES common stock exceeds the TSR of the Standard and Poor s 500 (S&P 500) over the three-year measurement period beginning on January 1st in the year of grant and ending after three years on December 31st. In certain situations where the TSR of both AES common stock and the S&P 500 exhibit a gain over the measurement period, the grant may vest without the TSR of AES common stock exceeding the TSR of the S&P 500, if the Compensation Committee exercises its discretion to permit such vesting. The units are then required to be held for an additional two years subsequent to vesting before they can be redeemed for shares, and thus become transferable. In all circumstances, restricted stock units granted by AES do not entitle the holder the right, or obligate AES, to settle the restricted stock unit in cash or other assets of AES.

The effect of the market condition on restricted stock units issued to officers of the Company is reflected in the award s fair value on the grant date for the year ended December 31, 2009. A discount of 0.5% was applied to the closing price of the Company s stock on the date of grant to estimate the fair value to reflect the market condition for RSUs with market conditions granted during the year ended December 31, 2009. RSUs that included a market condition granted during the year ended December 31, 2009 and 2008 had a grant date fair value per RSU of $6.68 and $16.23, respectively. The total grant date fair value of RSUs with a market condition granted during the year ended December 31, 2009 was $4.9 million. If no discount was applied to reflect the market condition for RSUs issued to officers, the total grant date fair value of RSUs with a market condition granted during year ended December 31, 2009 would have increased by an immaterial amount.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following table summarizes the components of the Company s stock-based compensation related to its RSUs granted with market conditions recognized in the Company s financial statements:

	2009	December 31, 2008 (in millions)	2007
RSU expense before income tax	$ 4	$ 4	$ 5
Tax benefit	(1)	(1)	(2)
RSU expense, net of tax	$ 3	$ 3	$ 3
Total value of RSUs converted[(1)]	$ 4	$	$
Total fair value of RSUs vested[(2)]	$	$ 5	$ 5

(1) Amount represents fair market value on the date of conversion.

(2) RSUs granted in 2006 with a market condition did not vest in 2009 because the TSR on AES common stock did not exceed the TSR of the S&P 500 over the three year vesting period.

There was no cash used to settle RSUs or compensation cost capitalized as part of the cost of an asset for the years ended December 31, 2009, 2008 and 2007. As of December 31, 2009, $5 million of total unrecognized compensation cost related to RSUs with a market condition is expected to be recognized over a weighted average period of approximately 1.8 years. There were no modifications to RSU awards during the year ended December 31, 2009.

A summary of the restricted stock unit activity for the year ended December 31, 2009 follows (number of RSUs in thousands):

	RSUs	Weighted Average Grant-date Fair Values	Weighted Average Remaining Vesting Term
Nonvested at December 31, 2008	765	$ 14.93	
Vested year to date			
Forfeited and expired year to date	(604)	13.70	
Granted year to date	733	6.68	
Nonvested at December 31, 2009	894	$ 9.00	1.9
Vested at December 31, 2009	352	$ 16.81	
Vested and expected to vest at December 31, 2009	1,127	$ 11.33	

The table below summarizes the RSUs with a market condition that vested and were converted during the years ended 2009, 2008 and 2007 (number of RSUs in thousands):

	December 31,		
	2009	2008	2007
RSUs vested during the year		352	548
RSUs converted during the year[1]	410		

(1) Net of shares withheld for taxes of 153,000 during the year ended December 31, 2009.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

17. SUBSIDIARY STOCK

The Company held $60 million of cumulative preferred stock of a subsidiary at December 31, 2009 and 2008. This represented five series of preferred stock of IPL, the Company s integrated utility in Indiana. The total annual dividend requirements were approximately $3 million at December 31, 2009 and 2008. Certain series of the preferred stock were redeemable solely at the option of the issuer at prices between $100 and $118 per share. Holders of the preferred stock are entitled to elect a majority of IPL s board of directors if IPL has not paid dividends to its preferred stockholders for four full quarters. Based on the preferred stockholders ability to elect a majority of IPL s board of directors in this circumstance, the redemption of the preferred shares is considered to be not solely within the control of the issuer and the preferred stock is considered temporary equity and presented in the mezzanine level of the consolidated balance sheets in accordance with the relevant accounting guidance for non-controlling interests and redeemable securities.

In February 2009, in connection with a preemptive rights period associated with a share issuance (capital increase) at AES Gener, Inversiones Cachagua Limitada (Cachagua), a wholly-owned subsidiary of the Company, paid $175 million to AES Gener to maintain its current ownership percentage of approximately 70.6%.

On November 6, 2008, Cachagua sold a 9.6% ownership interest in AES Gener in a private transaction for $174.9 million. The sale reduced the Company s ownership percentage of AES Gener from 80.2% to 70.6%. The Company recognized a pre-tax loss of $30.8 million, net of $3.6 million of related fees, from this transaction in the fourth quarter of 2008.

In May and October 2007, Cachagua sold a 0.9% and 10.2% ownership interest, respectively, in AES Gener for $330.9 million. The sale reduced the Company s ownership percentage of AES Gener to 80.2%. The Company recorded a pre-tax gain on the sale of $134.2 million, including $8.3 million of related fees.

18. OTHER INCOME AND EXPENSE

The components of other income are summarized as follows:

	Years Ended December 31,		
	2009	2008	2007
		(in millions)	
Extinguishment of tax liabilities	$ 165	$	$
Tax credit settlement	129		
Management performance incentive	80		
Gain on extinguishment of liabilities	3	199	22
Insurance proceeds		40	18
Gain on sale of assets	14	34	24
Contract settlement gain			135
Gross receipts tax recovery			93
Other	75	104	66
Total other income	$ 466	$ 377	$ 358

Other income generally includes gains on asset sales and extinguishments of liabilities, favorable judgments on contingencies, and other income from miscellaneous transactions.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

Other income of $466 million for the year ended December 31, 2009 included $165 million from the reduction in interest and penalties associated with federal tax debts at Eletropaulo and Sul as a result of the Programa de Recuperacao Fiscal (Refis) program and a $129 million gain related to a favorable court decision enabling Eletropaulo to receive reimbursement of excess non-income taxes paid from 1989 to 1992 in the form of tax credits to be applied against future tax liabilities. The net impact to the Company after income taxes and noncontrolling interests for these items was $44 million. In addition, the Company recognized income of $80 million from a performance incentive bonus for management services provided to Ekibastuz and Maikuben in 2008. The management agreement was related to the sale of these businesses in Kazakhstan in May 2008; see further discussion of this transaction in Note 22 *Acquisitions and Dispositions.*

Other income of $377 million for the year ended December 31, 2008 included gains on the extinguishment of a gross receipts tax liability and a legal contingency at Eletropaulo of $117 million and $75 million, respectively, $32 million of cash proceeds related to a favorable legal settlement at Southland in California, $29 million of insurance recoveries for damaged turbines at Uruguaiana, $23 million of gains associated with a sale of land at Eletropaulo and sales of turbines at Itabo, and compensation of $18 million for the impairment associated with the settlement agreement to shut down Hefei.

Other income of $358 million for the year ended December 31, 2007 included a $135 million contract settlement gain at Eastern Energy in New York, a $93 million gross receipts tax recovery at Eletropaulo and Tiete, and favorable legal settlements at Eletropaulo and Red Oak in New Jersey.

The components of other expense are summarized as follows:

	Years Ended December 31,		
	2009	**2008**	**2007**
		(in millions)	
Loss on extinguishment of liabilities	$	$ 70	$ 106
Loss on sale and disposal of assets	42	34	79
Other	69	57	68
Total other expense	$ 111	$ 161	$ 253

Other expense generally includes losses on asset sales, losses on extinguishment of debt, legal contingencies and losses from other miscellaneous transactions.

Other expense of $111 million for the year ended December 31, 2009 included a $13 million loss recognized when three of our businesses in the Dominican Republic received $110 million par value bonds issued by the Dominican Republic government to settle existing accounts receivable for the same amount from the government-owned distribution companies. The loss represented an adjustment to reflect the fair value of the bonds on the date received. Other expenses also included losses on the disposal of assets at Eletropaulo and Andres and contingencies at Alicura and our businesses in Kazakhstan.

Other expense of $161 million for the year ended December 31, 2008 included $69 million of losses on the retirement of debt at the Parent Company in connection with the refinancing in June 2008, as further discussed in Note 10 Long Term Debt, and IPALCO associated with a $375 million refinancing in April 2008, and losses on disposal of assets primarily at Eletropaulo in Brazil.

Other expense of $253 million for the year ended December 31, 2007 included a loss of $90 million on the retirement of Senior Secured Notes at the parent company, a $28 million charge related to an increase in contingencies in Kazakhstan and losses on sales and disposals of assets at Eletropaulo and Sul in Brazil.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

19. ASSET IMPAIRMENT EXPENSE

Asset impairment expense for the years ended December 31, 2009, 2008 and 2007 consisted of:

	2009 (in millions)
Piabanha	$ 11
Other	14
Total	$ 25

During the fourth quarter of 2009, the Company recognized a pre-tax long-lived asset impairment charge of $11 million related to the Company s Piabanha hydro project in Brazil. The Company determined that the carrying value exceeded the future discounted cash flows and abandoned the project.

	2008 (in millions)
LNG projects in North America	$ 67
Uruguaiana	36
South African peakers	31
Hefei	18
Other	23
Total	$ 175

In the fourth quarter of 2008 and in response to the financial market crisis, the Company reviewed and prioritized projects in the development pipeline. From this review, the Company determined that the carrying value exceeded the future discounted cash flows for certain projects. In accordance with the accounting standards for the impairment or disposal of long-lived assets, the Company recorded a total pre-tax impairment charge of $75 million ($34 million, net of noncontrolling interests and income taxes) related to two liquefied natural gas projects in North America and a non-power development project at one of our facilities in North America. These projects were reported in the North America Generation segment.

Following an initial impairment charge in the fourth quarter of 2007 at Uruguaiana, there were impairment charges of $36 million recognized during the first three quarters of 2008. The impairment was triggered by a combination of gas curtailments and increases in the spot market price of energy in 2007 that continued in 2008. The additional impairment charges in 2008 were primarily due to fixed asset purchase agreements in place. Uruguaiana is a thermoelectric generation plant located in Brazil and reported in the Latin America Generation segment.

The Company recognized impairment charges totaling $31 million related to a project in South Africa the Company withdrew from during the first quarter of 2008. These represented project development costs and an impairment of turbine deposits related to the project. All costs capitalized and incurred on the project have been written off as no future benefit is expected from these assets. This project was reported in Corporate and Other .

The Anhui Development and Reform commission issued notice to our Hefei plant in China, in March 2007 as a result of the 2007 State Council s decision to shut down smaller, inefficient and potentially polluting generation units nationwide. A settlement agreement was signed March 30, 2008 to end the contractual PPA arrangement. In accordance with the accounting standards for goodwill and other intangible assets, management

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

concluded that the assets were impaired in March 2008, since the long-lived asset group would be sold or otherwise disposed of significantly before the end of its previously estimated life. As a result, impairment charges of $18 million were recognized associated with the settlement agreement to shut down the Hefei plant, which is reported in the Asia Generation segment.

	2007 (in millions)
Uruguaiana	$ 352
Placerita	25
AgCert	14
Other	17
Total	$ 408

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. Based on the accounting guidance for the impairment or disposal of long-lived assets, management concluded that an impairment occurred during fourth quarter 2007 due to the carrying amount of its long-lived asset exceeding its fair value. The expected present value of future cash flows was used to estimate fair value. As a result of this impairment analysis, a pre-tax impairment charge of $352 million was recognized which represents a full impairment of the fixed assets. Uruguaiana is a thermoelectric plant located in Brazil and is reported in the Latin America Generation segment.

In August 2007, Placerita, a gas-fired combined cycle generation plant located in the United States, sustained property damage to the compressor section in one of its gas turbines. This event triggered an impairment analysis of the plant s long-lived assets, which resulted in a pre-tax impairment charge of approximately $25 million, which represents the net book value of the plant. It was determined that no future net cash flows would be received from the use of this long-lived asset and it was fully impaired. Placerita is reported in the North America Generation segment.

In May 2006, AES advanced AgCert, a United Kingdom based corporation that produces emission reduction credits, cash of $52 million. AES recognized this prepayment as a long-term asset as consideration for future CER credits and AgCert stock warrants. The asset was revalued each period based on current exchange rates. In the fourth quarter of 2007, AgCert notified AES that it was not able to meet its contractual obligations to deliver CERs, which triggered an analysis of the asset s recoverability. AgCert s financial information indicated a significant decrease in liquidity. As a result of the decline in liquidity and AgCert s inability to fulfill its contractual obligations for future delivery of the CERs, the Company recognized a pre-tax impairment charge of $14 million using the net present value of forecasted operations. This investment and long-term asset are reported in Corporate and Other .

Other Impairments

In addition to the asset impairment expense discussed above, other-than-temporary impairments of cost method investments of $12 million and $15 million were recorded in the years ended December 31, 2009 and 2008, respectively. These impairment charges primarily related to the Company s investment in 2007 in a company developing a commercial facility for a blue gas (coal to gas) technology project. The Company accounted for the investment in convertible preferred shares under the cost method of accounting. During the fourth quarter of 2008, the market value of the shares materially declined due to downward trends in the capital markets and management concluded that the decline was other-than-temporary and recorded an impairment

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

charge of $10 million. In 2009, this investment was determined to be further impaired and an additional $10 million other-than-temporary impairment charge, representing the remaining value of the shares, was recorded.

There was no other-than-temporary impairment of cost method investments in the year ended December 31, 2007.

20. INCOME TAXES

INCOME TAX PROVISION

The following table summarizes the expense for income taxes on continuing operations, for the years ended December 31, 2009, 2008 and 2007:

	December 31,		
	2009	2008 (in millions)	2007
Federal:			
Current	$ 3	$ 12	$ 2
Deferred	(146)	122	5
State:			
Current		(1)	2
Deferred	(9)	(7)	8
Foreign:			
Current	552	611	475
Deferred	199	34	184
Total	$ 599	$ 771	$ 676

EFFECTIVE AND STATUTORY RATE RECONCILIATION

The following table summarizes a reconciliation of the U.S. statutory federal income tax rate to the Company s effective tax rate, as a percentage of income from continuing operations before taxes for the years ended December 31, 2009, 2008 and 2007:

	December 31,		
	2009	2008	2007
Statutory Federal tax rate	35%	35%	35%
State taxes, net of Federal tax benefit	(1)		(1)
Taxes on foreign earnings	(5)	(4)	13
Valuation allowance		2	(2)
Gain on sale of Kazakhstan businesses	(3)	(12)	
Taxes on cash repatriation		6	
Other net		2	1
Effective tax rate	26%	29%	46%

236

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The current income taxes receivable and payable are included in Other Current Assets and Accrued and Other Liabilities, respectively, on the accompanying Consolidated Balance Sheets. The noncurrent income taxes receivable and payable are included in Other Assets and Other Long-Term Liabilities respectively, on the accompanying Consolidated Balance Sheets. The following table summarizes the income taxes receivable and payable as of December 31, 2009 and 2008:

	December 31, 2009	December 31, 2008
	(in millions)	
Income taxes receivable current	$ 434	$ 326
Income taxes receivable noncurrent	22	1
Total income taxes receivable	$ 456	$ 327
Income taxes payable current	$ 508	$ 377
Income taxes payable noncurrent	11	10
Total income taxes payable	$ 519	$ 387

DEFERRED INCOME TAXES Deferred income taxes reflect the net tax effects of (a) temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes, and (b) operating loss and tax credit carry forwards. These items are stated at the enacted tax rates that are expected to be in effect when taxes are actually paid or recovered.

As of December 31, 2009, the Company had federal net operating loss carry forwards for tax purposes of approximately $2.1 billion expiring in years 2020 to 2029. Due to a transaction undertaken in the second quarter of 2009, the federal net operating loss carryforward now includes a U.S. entity that previously was not included in the U.S. consolidated tax group. Approximately $68 million of the net operating loss carry forward related to stock option deductions will be recognized in additional paid-in capital when realized. The Company also had federal general business tax credit carry forwards of approximately $18 million expiring primarily from 2021 to 2029, and federal alternative minimum tax credits of approximately $14 million that carry forward without expiration. The Company had state net operating loss carry forwards as of December 31, 2009 of approximately $3.4 billion expiring in years 2012 to 2029. As of December 31, 2009, the Company had foreign net operating loss carry forwards of approximately $4.3 billion that expire at various times beginning in 2010 and some of which carry forward without expiration, and tax credits available in foreign jurisdictions of approximately $36 million, $3 million of which expire in 2010 to 2012, $14 million of which expire in 2013 to 2020 and $19 million of which carry forward without expiration.

Valuation allowances increased by $268 million during 2009 to $1.7 billion at December 31, 2009. This net increase was primarily the result of an increase in foreign net operating loss carryforwards that required full offsetting valuation allowances.

Valuation allowances decreased by $210 million during 2008 to $1.4 billion at December 31, 2008. This net decrease was primarily the result of decreases in deferred tax assets at certain Brazilian subsidiaries that required corresponding decreases in the valuation allowances.

The Company believes that it is more likely than not that the remaining deferred tax assets as shown below will be realized when future taxable income is generated through the reversal of existing taxable temporary differences and income that is expected to be generated by businesses that have long-term contracts or a history of generating taxable income. The Company is monitoring the utilization of its deferred tax asset for its

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

U.S. consolidated net operating loss carry forward. Although management believes it is more likely than not that this deferred tax asset will be realized through generation of sufficient taxable income prior to expiration of the loss carry forwards, such realization is not assured.

The following table summarizes the deferred tax assets and liabilities, as of December 31, 2009 and 2008:

	December 31, 2009	December 31, 2008
	(in millions)	
Differences between book and tax basis of property	$ 1,772	$ 1,641
Other taxable temporary differences	310	326
Total deferred tax liability	$ 2,082	$ 1,967
Operating loss carryforwards	(1,701)	(1,201)
Capital loss carryforwards	(107)	(298)
Bad debt and other book provisions	(562)	(495)
Retirement costs	(283)	(169)
Tax credit carryforwards	(68)	(70)
Cumulative translation adjustment	(200)	(240)
Other deductible temporary differences	(531)	(478)
Total gross deferred tax asset	(3,452)	(2,951)
Less: valuation allowance	1,677	1,409
Total net deferred tax asset	(1,775)	(1,542)
Net deferred tax liability	$ 307	$ 425

The Company considers undistributed earnings of certain foreign subsidiaries to be indefinitely reinvested outside of the United States and, accordingly, no U.S. deferred taxes have been recorded with respect to such earnings in accordance with the relevant accounting guidance for income taxes. Should the earnings be remitted as dividends, the Company may be subject to additional U.S. taxes, net of allowable foreign tax credits. It is not practicable to estimate the amount of any additional taxes which may be payable on the undistributed earnings.

Income from operations in certain countries is subject to reduced tax rates as a result of satisfying specific commitments regarding employment and capital investment. The Company s income tax benefits related to the tax status of these operations are estimated to be $47 million, $35 million and $42 million for the years ended December 31, 2009, 2008 and 2007, respectively.

The following table summarizes the income (loss) from continuing operations, before income taxes, net equity in earnings of affiliates and noncontrolling interests, for the years ended December 31, 2009, 2008 and 2007:

December 31,

	2009	2008 (in millions)	2007
U.S.	$ (976)	$ (314)	$ (165)
Non-U.S.	3,319	3,011	1,622
Total	$ 2,343	$ 2,697	$ 1,457

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

UNCERTAIN TAX POSITIONS

Uncertain tax positions have been classified as non-current income tax liabilities unless expected to be paid in one year. The Company s policy for interest and penalties related to income tax exposures is to recognize interest and penalties as a component of the provision for income taxes in the Consolidated Statements of Operations.

As of December 31, 2009 and 2008, the total amount of gross accrued income tax related interest included in the Consolidated Balance Sheets was $21 million and $25 million, respectively. The total amount of gross accrued income tax related penalties included in the Consolidated Balance Sheets as of December 31, 2009 and 2008 was $5 million and $5 million, respectively.

The total expense for interest related to unrecognized tax benefits for the years ended December 31, 2009, 2008 and 2007 amounted to $4 million, $2 million and $15 million, respectively. For the years ended December 31, 2009, 2008 and 2007, the total expense (benefit) for penalties related to unrecognized tax benefits amounted to $ million, $(2) million and $4 million, respectively.

We are potentially subject to income tax audits in numerous jurisdictions in the U.S. and internationally until the applicable statute of limitation expires. Tax audits by their nature are often complex and can require several years to complete. The following is a summary of tax years potentially subject to examination in the significant tax and business jurisdictions in which we operate:

Jurisdiction	Tax Years Subject to Examination
Argentina	2003-2009
Brazil	2003-2009
Cameroon	2007-2009
Chile	1998-2009
El Salvador	2005-2009
United Kingdom	1999-2009
United States (Federal)	1994-2009

As of December 31, 2009, 2008 and 2007, the total amount of unrecognized tax benefits was $511 million, $555 million and $590 million, respectively. The total amount of unrecognized tax benefits that would benefit the effective tax rate as of December 31, 2009, 2008 and 2007 is $484 million, $527 million and $533 million, respectively, of which $55 million, $131 million and $144 million, respectively, would be in the form of tax attributes that would warrant a full valuation allowance.

The total amount of unrecognized tax benefits anticipated to result in a net decrease of unrecognized tax benefits within 12 months of December 31, 2009 is estimated to be between $4 million and $5 million.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following is a reconciliation of the beginning and ending amounts of unrecognized tax benefits for the years ended December 31, 2009, 2008 and 2007:

	2009	December 31, 2008 (in millions)	2007
Balance at January 1	$ 555	$ 590	$ 559
Additions for current year tax positions	72	6	18
Additions for tax positions of prior years	7	80	39
Reductions for tax positions of prior years	(9)	(26)	(21)
Effects of foreign currency translation	6	(74)	18
Settlements	(104)	(18)	(22)
Lapse of statute of limitations	(16)	(3)	(1)
Balance at December 31	$ 511	$ 555	$ 590

The amount of settlements of uncertain tax positions in 2009 was primarily the result of a non-cash audit settlement for $105 million at a Brazilian subsidiary which resulted in no tax expense or benefit.

The Company and certain of its subsidiaries are currently under examination by the relevant taxing authorities for various tax years. The Company regularly assesses the potential outcome of these examinations in each of the taxing jurisdictions when determining the adequacy of the amount of unrecognized tax benefit recorded. While it is often difficult to predict the final outcome or the timing of resolution of any particular uncertain tax position, we believe we have appropriately accrued for our uncertain tax benefits. However, audit outcomes and the timing of audit settlements and future events that would impact our previously recorded unrecognized tax benefits and the range of anticipated increases or decreases in unrecognized tax benefits are subject to significant uncertainty. It is possible that the ultimate outcome of current or future examinations may exceed our provision for current unrecognized tax benefits in amounts that could be material, but cannot be estimated as of December 31, 2009. Our effective tax rate and net income in any given future period could therefore be materially impacted.

21. DISCONTINUED OPERATIONS AND HELD FOR SALE BUSINESSES

The following table summarizes the income (loss) on disposal and impairment for the following discontinued operations for the years ended December 31, 2009, 2008 and 2007:

Subsidiary	2009	December 31, 2008 (in millions)	2007
Central Valley	$	$ (1)	$ 20
EDC			(680)
Eden			(1)
Jiaozuo		7	
Lal Pir	(74)		
Pak Gen	(76)		

(Loss) gain on disposal and impairment, after taxes	$ (150)	$ 6	$ (661)

In December 2009, the Company entered into agreements to sell its interests in three generation businesses located in Pakistan and Oman, reported in the Asia Generation segment. The businesses, Lal Pir and Pak Gen,

240

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

located in Pakistan, and Barka, located in Oman, will be sold to two separate buyers. The sales are expected to close in the first half of 2010. Upon completion of the transactions, the company will sell its 55% ownership in Lal Pir and Pak Gen, two oil-fired facilities with respective generation capacities of 362 MW and 365 MW. Further, the company will also sell its 35% ownership interest in Barka, a 456MW combined cycle gas facility and water desalination plant and its 100% ownership interest in two Barka related service companies. The Company will receive proceeds upon the closing of the two transactions of approximately $200 million before purchase price adjustments. The Company recognized an impairment after noncontrolling interests of $105 million against its share of Lal Pir and Pak Gen, which represents the net book value of the Company s investment in Lal Pir and Pak Gen less the fair value.

In December 2008, the Company reached an agreement to sell its 70% equity interest in Jiaozuo AES Wanfang Power Co., Ltd. (Jiaozuo), which is reported in the Asia Generation segment, for approximately $73 million net of any withholding taxes. The AES Board of Directors approved the sale of Jiaozuo which closed on December 15, 2008 and the Company recognized a gain on the sale of approximately $7 million. Goodwill of $4 million was written off in connection with the gain on sale. This gain is included in the 2008 gain (loss) from disposal of discontinued businesses line item on the consolidated Statement of Operations for the year ended December 31, 2008.

On February 22, 2007, the Company entered into a definitive agreement with Petróleos de Venezuela, S.A., (PDVSA) to sell all of its shares of EDC, a distribution business reported in the Latin America Utilities segment, for $739 million, net of any withholding taxes. In addition, the agreement provided for the payment of a $120 million dividend in 2007 which was declared on March 1, 2007 payable to the EDC shareholders of record as of March 9, 2007. A wholly-owned subsidiary of the Company was the owner of 82.14% of the outstanding shares of EDC, and therefore, on May 31, 2007, received approximately $97 million in dividends (representing approximately $99 million in gross dividends offset by fees). The sale of EDC and the payment of the purchase price occurred on May 16, 2007. EDC is classified as discontinued operations and reflected as such on the face of the Consolidated Financial Statements for all periods presented. During the first quarter of 2007, the Company recognized an impairment charge of approximately $638 million related to this sale. As a result of the final disposition of EDC in May 2007, the Company recognized an additional impairment charge of approximately $42 million, net of income and withholding taxes. The total impairment charge of $680 million represented the net book value of the Company s investment in EDC less the selling price. The Company impaired the carrying value of EDC s electric generation and distribution assets to their net realizable value. The impairment expense was included in the loss from disposal of discontinued businesses line item on the Consolidated Statement of Operations for the year ended December 31, 2007.

In July 2007, the Company s wholly-owned subsidiary, Central Valley, sold 100% of its indirect interest in two biomass fired power plants located in central California (the 50 MW Delano facility and the 25 MW Mendota facility) for $51 million. These facilities, along with an associated management company (together, the Central Valley Businesses) were included in the North America Generation segment. Central Valley is classified as discontinued operations in the Company s Consolidated Financial Statements for all periods presented. The Company recognized a gain on the sale of approximately $20 million net of income and withholding taxes.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

Information for business components included in discontinued operations is as follows:

	December 31, 2009	2008	2007
	(in millions)		
Revenue	$ 571	$ 811	$ 882
Income from operations of discontinued businesses, before taxes	72	74	193
Income tax expense	(3)	(7)	(32)
Income from operations of discontinued businesses	$ 69	$ 67	$ 161
Gain (loss) on disposal of discontinued businesses, after taxes	$ (150)	$ 6	$ (661)

As further discussed in Note 22 Acquisitions and Dispositions, in February 2008, the Company entered into an agreement to sell two of its wholly-owned subsidiaries in Kazakhstan, AES Ekibastuz LLP (Ekibastuz) and Maikuben West LLP (Maikuben). These businesses are included in the Europe Generation segment. Total consideration for the transaction was approximately $1.1 billion with potential earn-out provisions up to an additional $381 million over a three-year period. These businesses generated total revenue of $114 million and $106 million, and net income (loss) of $61 million and $(35) million for the years ended December 31, 2008 and 2007, respectively, excluding intercompany transactions. The sale was completed on May 30, 2008. As a result of AES s continuing involvement in the management and operations of the businesses after the sale was completed, their results of operations continued to be reflected as part of income from continuing operations for all periods presented. Revenue recognized subsequent to the sale represented the management fees earned for the Company s continued management of the operations of the businesses.

22. ACQUISITIONS AND DISPOSITIONS

Acquisitions

In April 2008, the Company completed the purchase of a 92% interest in a 660 gross MW coal-fired thermal power generation facility in Masinloc, Philippines (Masinloc) from the Power Sector Assets & Liabilities Management Corporation, a state enterprise, for $930 million in cash. Project financing of $665 million was obtained from International Finance Corporation (IFC), the Asian Development Bank and a consortium of commercial banks. IFC is also an 8% minority shareholder in Masinloc. AES immediately embarked upon a comprehensive rehabilitation program to improve the output, reliability and general condition of the plant. Environmental clean-up costs have been estimated pending a detailed study. Including transaction costs and completion of the planned upgrade program to improve environmental and operational performance, the total project cost is estimated to be $1.1 billion. Beginning on the acquisition date in April 2008, the results of operations of Masinloc are reflected in the Consolidated Financial Statements. The Company finalized the purchase price allocation of this acquisition in the fourth quarter of 2008.

Dispositions

On May 30, 2008 the Company completed the sale of two of its wholly-owned subsidiaries in Kazakhstan, Ekibastuz, a coal-fired generation plant, and Maikuben, a coal mine. Total consideration received in the transaction was approximately $1.1 billion plus additional potential earn-out provisions, a three-year management and operation agreement and a capital expenditures program bonus. Due to the fact that AES was to have significant continuing involvement in the management and operations of the businesses through its three-year management and operation agreement, the results of operations from Ekibastuz and Maikuben were

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

included in income from continuing operations through the date of the disposition. Income earned as a result of the three-year management and operation agreement has been recognized as management fee income for all periods subsequent to the disposition.

On March 23, 2009, the Company and Kazakhmys PLC (Kazakhmys), which purchased the subsidiaries, mutually agreed to terminate the original sale agreement and the three-year management and operation agreement. In connection with the termination of these agreements, the Company and Kazakhmys entered into a new agreement (the 2009 Agreement). Under the 2009 Agreement, Kazakhmys agreed to pay the Company an $80 million performance incentive bonus in April 2009 for management services provided in 2008. This was recognized as Other Income in the Company s condensed consolidated statement of operations during the first quarter of 2009. The cash was received by the Company in April 2009. A $13 million gain was recognized related to a reversal of a tax contingency for a contractual obligation, under which the Company provided indemnification to Kazakhmys, which expired in January 2009. This was recorded as an adjustment to the gain on the sale of Ekibastuz and Maikuben during the first quarter of 2009.

The 2009 agreement also provided for an additional $102 million payment, primarily related to the termination of the management agreement, payable to AES in January 2010. In May 2009, Kazakhmys provided an irrevocable standby letter of credit from a credit worthy institution to AES of $102 million to secure the final payment. The payment of the final component of the management termination agreement was not contingent upon any future events. As a result, the Company recognized an additional gain on the sale of Ekibastuz and Maikuben of approximately $98.5 million in the second quarter of 2009. AES received the final payment of $102 million from Kazakhmys in January 2010.

The parties agreed to terminate both the Stock Purchase Agreement and the Management Agreement, and have further agreed to a mutual release of prior claims. As part of the management termination agreement, AES agreed to transition the management of the businesses to Kazakhmys over a period of 100 days from March 13, 2009. The transition period ended June 21, 2009 and at that time the management of Ekibastuz and Maikuben became the responsibility of Kazakhmys. The Company s involvement with the businesses remained in place for more than one year from the date of the sale; therefore, the Company has continued to include the businesses as part of continuing operations in the condensed consolidated financial statements for all periods presented, despite the termination of the management agreement.

Excluding income earned under the three-year management and operation agreement (terminated in March 2009), Ekibastuz and Maikuben generated no revenue in 2009 and generated revenue of $114 million and $106 million for the years ended December 31, 2008 and 2007, respectively.

23. EARNINGS PER SHARE

Basic and diluted earnings per share are based on the weighted average number of shares of common stock and potential common stock outstanding during the period, after giving effect to stock splits. Potential common stock, for purposes of determining diluted earnings per share, includes the effects of dilutive restrictive stock units, stock options and convertible securities. The effect of such potential common stock is computed using the treasury stock method or the if-converted method, as applicable.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

The following table presents a reconciliation of the numerators and denominators of the basic and diluted earnings per share computations for income from continuing operations. In the table below, income represents the numerator (in millions) and shares represent the denominator (in millions):

	December 31, 2009			December 31, 2008			December 31, 2007		
	Income	Shares	$ per Share	Income	Shares	$ per Share	Income	Shares	$ per Share
BASIC EARNINGS PER SHARE									
Income from continuing operations attributable to The AES Corporation common stockholders	$ 729	667	$ 1.09	$ 1,189	669	$ 1.78	$ 454	668	$ 0.68
EFFECT OF DILUTIVE SECURITIES									
Convertible securities				22	15	(0.02)			
Stock options and warrants		1			4			9	(0.01)
Restricted stock units		2			1			1	
DILUTED EARNINGS PER SHARE	$ 729	670	$ 1.09	$ 1,211	689	$ 1.76	$ 454	678	$ 0.67

The calculation of diluted earnings per share excluded 18,035,813, 11,150,853 and 5,740,727 options outstanding at December 31, 2009, 2008 and 2007, respectively, that could potentially dilute basic earnings per share in the future. Those options were not included in the computation of diluted earnings per share because the exercise price of those options exceeded the average market price during the related period. In 2008, all convertible debentures were included in the earnings per share calculation. In 2009 and 2007, all convertible debentures were omitted from the earnings per share calculation because they were antidilutive.

24. RISKS AND UNCERTAINTIES

AES is a global power producer in 29 countries on five continents. See additional discussion of the Company s principal markets in Note 15 Segment and Geographic Information. Our principal lines of business are Generation and Utilities. The Generation line of business uses a wide range of technologies, including coal, gas, hydroelectric, and biomass as fuel to generate electricity. Our Utilities business is comprised of businesses that transmit, distribute, and in certain circumstances generate power. In addition, the Company continues to expand its reach into the renewables area. These efforts include projects primarily in wind and solar.

POLITICAL AND ECONOMIC RISKS The Company s market capitalization was negatively impacted largely in the second half of 2008 and in 2009. During this period, credit markets and global markets deteriorated and experienced increased market volatility, which can pose risks to the overall liquidity and/or asset values of our businesses with heightened unpredictability in currencies, counterparty credit risk and the widening of credit spreads in certain markets. If market conditions are protracted or continue to deteriorate, the Company may be at risk to decreased earnings and cash flows due to, among other factors, adverse fluctuations in the commodities and foreign currency spot markets or deterioration in global macroeconomic conditions. With the tightening of the credit markets, there is a risk that future investments may not be able to be financed through accessing capital and debt markets and may be subject to restrictions in the near future.

Currently, the Company has a below-investment grade rating from Standard & Poor s of BB-. This may limit the ability of the Company to finance new and existing development projects to cash currently available on hand and through reinvestment of earnings. As of December 31, 2009, the Company had $1.8 billion of unrestricted cash and cash equivalents.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

During 2009, approximately 82% of our revenue, and all of our revenue from discontinued businesses, was generated outside the United States and a significant portion of our international operations is conducted in developing countries. While our growth strategy evolved as 2009 progressed, to focus on targeted projects in order to maintain our liquidity, we continue to invest in projects 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;
- 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, individually or in combination with others, could materially and adversely affect our business, results of operations and financial condition. In addition, our Latin American operations experience volatility in revenue and earnings which have caused and are expected to cause significant volatility in our results of operations and cash flows. The volatility is caused by regulatory and economic difficulties, political instability 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.

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 analysts expectations. Furthermore, changes in laws or regulations or changes in the application or interpretation of regulatory provisions in jurisdictions where we operate, particularly our Utilities businesses where electricity tariffs are subject to regulatory review or approval, could adversely affect our business, including, but not limited to:

changes in the determination, definition or classification of costs to be included as reimbursable or pass-through costs;

245

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

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;

other changes in the regulatory determinations under the relevant concessions; or

changes in environmental regulations, including regulations relating to GHG emissions in any of our businesses.

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

RISKS RELATED TO FOREIGN CURRENCIES AES operates businesses in many foreign environments and such operations in foreign countries may be impacted by significant fluctuations in foreign currency exchange rates. The Company s financial position and results of operations have been significantly affected by fluctuations in the value of the Brazilian real, the Argentine peso, the Dominican Republic peso, the Euro, the Chilean peso, the Colombian peso and the Philippine peso relative to the U.S. Dollar.

RISKS RELATED TO POWER SALES CONTRACTS Several of the Company s power plants rely on power sales contracts with one or a limited number of entities for the majority of, and in some case all of, the relevant plant s output over the term of the power sales contract. The remaining term of the power sales contracts related to the Company s power plants range from less than one to 37 years. No single customer accounted for 10% or more of total revenue in 2009, 2008, or 2007.

The cash flows and results of operations of such plants are dependent on the credit quality of the purchasers and the continued ability of their customers and suppliers to meet their obligations under the relevant power sales contract. If a substantial portion of the Company s long-term power sales contracts were modified or terminated, the Company would be adversely affected to the extent that it was unable to find other customers at the same level of contract profitability. The loss of one or more significant power sales contracts or the failure by any of the parties to a power sales contract to fulfill its obligations thereunder could have a material adverse impact on the Company s business, results of operations and financial condition.

25. OFF-BALANCE SHEET ARRANGEMENTS AND RELATED PARTY TRANSACTIONS

IPL, a consolidated subsidiary of the Company, formed IPL Funding Corporation (IPL Funding) in 1996 as a special purpose entity to purchase, on a revolving basis, the receivables originated by IPL. IPL Funding is not a qualified special purpose entity and is consolidated by IPL and IPALCO. IPL Funding entered into a sale facility with unrelated parties (the Purchasers) pursuant to which the Purchasers agree to purchase from IPL Funding, on a revolving basis, interests in the pool of receivables purchased from IPL up to the lesser of (1) an amount determined pursuant to the sale facility that takes into account certain eligibility requirements and reserves relating to the receivables, or (2) $50 million. Historically that amount has remained at $50 million, but during the fourth quarter of 2009, IPL s eligible receivables balance was below $50 million and IPL was required to repay the Purchasers the shortfall, which was approximately $10 million as of December 31, 2009. As collections reduce accounts receivable included in the pool, IPL Funding sells ownership interests in additional receivables acquired from IPL to return the ownership interests sold to the maximum amount permitted by the sale facility. During the second quarter of 2009, this agreement was extended through May 25, 2010. Accounts receivable on the Company s consolidated balance sheets are stated net of the $40 million and $50 million sold

246

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

as of December 31, 2009 and 2008, respectively and include $88 million and $87 million as of December 31, 2009 and 2008, respectively, related to IPL Funding s accounts receivable.

IPL retains servicing responsibilities for its role as a collection agent on the amounts due on the sold receivables. However, the Purchasers assume the risk of collection on the purchased receivables without recourse to IPL in the event of a loss. While no direct recourse to IPL exists, it risks loss in the event collections are not sufficient to allow for full recovery of its retained interests. No servicing asset or liability is recognized since the servicing fee paid to IPL approximates a market rate.

The carrying values of the retained interests are determined by allocating the carrying value of the receivables between the assets sold and the interests retained based on relative fair value. The key assumptions in estimating fair value are credit losses, the selection of discount rates and expected receivables turnover rate. The hypothetical effect on the fair value of the retained interests assuming both a 10% and a 20% unfavorable variation in credit losses or discount rates is not material due to the short turnover of receivables and historically low credit loss history.

The losses recognized on the sales of receivables were $1 million, $2 million and $3 million for the years ended December 31, 2009, 2008 and 2007, respectively. These losses are included in other expense on the consolidated statements of operations. The amount of the losses recognized depends on the previous carrying amount of the financial assets involved in the transfer, allocated between the assets sold and the interests that continue to be held by the transferor based on their relative fair value at the date of transfer, and the proceeds received.

There were no proceeds from new securitizations for each of the years ended December 31, 2009 and 2008. IPL Funding pays IPL annual service fees totaling $1 million, which is financed by capital contributions from IPL to IPL Funding.

The following table shows the receivables sold and retained interests as of December 31, 2009 and 2008:

	2009	2008
	(in millions)	
Receivables at IPL Funding	$ 128	$ 137
Less: Retained interests	88	87
Net receivables sold	$ 40	$ 50

The following table shows the cash flows for the years ended December 31, 2009, 2008 and 2007:

	2009	2008	2007
		(in millions)	
Cash proceeds from interest retained	$ 690	$ 623	$ 541
Cash proceeds from sold receivables	$ 315	$ 363	$ 419

IPL and IPL Funding provide certain indemnities to the Purchasers, including indemnification in the event that there is a breach of representations and warranties made with respect to the purchased receivables. IPL Funding and IPL each have agreed to indemnify the Purchasers on an after-tax basis for any and all damages, losses, claims, liabilities, penalties, taxes, costs and expenses at any time imposed on or incurred by the indemnified parties arising out of, or otherwise relating to, the sale facility, subject to certain limitations as defined in the sale facility.

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

Under the sale facility, if IPL fails to maintain certain financial covenants including, but not limited to interest coverage and debt to capital ratios, it would constitute a termination event. As of December 31, 2009, IPL was in compliance with such covenants. In the event that IPL s credit rating falls below a threshold identified in the sale facility, the facility agent has the ability to replace IPL as the collection agent and declare a lock-box event. Under a lock-box event or a termination event, the facility agent has the ability to require all proceeds of purchased receivables of IPL to be directed to lock-box accounts within 45 days of notifying IPL. In addition, a termination event would also give the facility agent the option to take control of the lock-box account, give the Purchasers the option to discontinue the purchase of new receivables, and require all proceeds to be used to reduce the Purchaser s investment and pay other amounts owed to the Purchasers and the facility agent. This could reduce the operating capital available to IPL by the aggregate amount of any purchased receivables up to $50 million.

Our generation businesses in Panama are partially owned by the Government of Panama (the Government). The Government, in turn, partially owns the distribution companies within Panama. For the years ended December 31, 2009, 2008 and 2007, our Panamanian businesses recognized electricity sales to the Government totaling $143 million, $203 million and $168 million, respectively. For the same period, our Panamanian businesses purchased electricity, which excludes transmission charges from the Government, totaling $25 million, $27 million and $24 million, respectively. As of December 31, 2009 and 2008, our Panamanian businesses owed the Government $7 million and $2 million, respectively, payable on normal trade terms. For the same period, the Government owed our Panamanian businesses $25 million and $29 million, respectively, payable on normal trade terms.

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

26. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarterly Financial Data

The following tables summarize the unaudited quarterly statements of operations for the Company for 2009 and 2008. Amounts reflect all adjustments necessary in the opinion of management for a fair statement of the results for interim periods.

	Quarter ended 2009			
	Mar 31	June 30	Sept 30	Dec 31
	(in millions, except per share data)			
Revenue	$ 3,269	$ 3,335	$ 3,695	$ 3,820
Gross margin	856	823	985	831
Income from continuing operations, net of tax	482	513	423	418
Discontinued operations, net of tax	20	17	17	(135)
Net income	502	530	440	283
Net income (loss) attributable to The AES Corporation	$ 218	303	185	(48)
Basic income per share:				
Income from continuing operations attributable to The AES Corporation, net of tax	$ 0.31	$ 0.44	$ 0.27	$ 0.08
Discontinued operations attributable to The AES Corporation, net of tax	0.02	0.01	0.01	(0.15)
Basic income (loss) per share attributable to The AES Corporation	$ 0.33	$ 0.45	$ 0.28	$ (0.07)
Diluted income per share:				
Income from continuing operations attributable to The AES Corporation, net of tax	$ 0.31	$ 0.44	$ 0.27	$ 0.08
Discontinued operations attributable to The AES Corporation, net of tax	0.02	0.01	0.01	(0.15)
Diluted income (loss) per share attributable to The AES Corporation	$ 0.33	$ 0.45	$ 0.28	$ (0.07)

Table of Contents

THE AES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2009, 2008, AND 2007

	Quarter ended 2008			
	Mar 31	June 30	Sept 30	Dec 31
	(in millions, except per share data)			
Revenue	$ 3,864	$ 3,939	$ 4,116	$ 3,439
Gross margin	1,013	1,008	943	668
Income from continuing operations, net of tax	386	1,141	352	80
Discontinued operations, net of tax	24	17	6	26
Net income	410	1,158	358	106
Net income (loss) attributable to The AES Corporation	$ 233	903	145	(47)
Basic income per share:				
Income from continuing operations attributable to The AES Corporation, net of tax	$ 0.33	$ 1.33	$ 0.21	$ (0.10)
Discontinued operations attributable to The AES Corporation, net of tax	0.02	0.01	0.01	0.03
Basic (loss) income per share attributable to The AES Corporation	$ 0.35	$ 1.34	$ 0.22	$ (0.07)
Diluted income per share:				
Income from continuing operations attributable to The AES Corporation, net of tax	$ 0.32	$ 1.30	$ 0.21	$ (0.10)
Discontinued operations attributable to The AES Corporation, net of tax	0.02	0.01	0.01	0.03
Diluted (loss) income per share attributable to The AES Corporation	$ 0.34	$ 1.31	$ 0.22	$ (0.07)

27. SUBSEQUENT EVENTS

Subsequent events have been evaluated through the date of issuance of this Form 10-K.

Table of Contents

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in the reports that the Company files or submits under the Securities Exchange Act of 1934, as amended (the Exchange Act), is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to the chief executive officer (CEO) and chief financial officer (CFO), as appropriate, to allow timely decisions regarding required disclosures.

The Company carried out the evaluation required by Rules 13a-15(b) and 15d-15(b), under the supervision and with the participation of our management, including the CEO and CFO, of the effectiveness of our disclosure controls and procedures (as defined in the Exchange Act Rules 13a-15(e) and 15d-15(e)). Based upon this evaluation, the CEO and CFO concluded that as of December 31, 2009, our disclosure controls and procedures were effective.

Management s Report on Internal Control Over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) under the Exchange Act. The Company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

- provide reasonable assurance that unauthorized acquisition, use or disposition of the Company s assets that could have a material effect on the financial statements are prevented or detected timely.

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

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2009. In making this assessment, management used the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations (COSO). Based on this assessment management believes that the Company maintained effective internal control over financial reporting as of December 31, 2009.

The effectiveness of the Company s internal control over financial reporting as of December 31, 2009, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which appears herein.

Changes in Internal Control Over Financial Reporting:

There were no changes that occurred during the quarter ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors and Stockholders of The AES Corporation:

We have audited The AES Corporation s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The AES Corporation s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control over Financial Reporting at Item 9A. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, The AES Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of The AES Corporation and its subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders equity and cash flows for each of the two years in the period ended December 31, 2009 of The AES Corporation and our report dated February 25, 2010 expressed an unqualified opinion thereon.

/s/: Ernst & Young LLP

McLean, Virginia

February 25, 2010

Table of Contents

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The following information is incorporated by reference from the 2010 Proxy Statement, File No. 001-12291, which will be filed on or around March 9, 2010 (the 2010 Proxy Statement):

Information regarding the directors required by this item found under the heading *Board of Directors*

Information regarding AES s Code of Ethics found under the heading *AES Code of Business Conduct and Corporate Governance Guidelines*

Information regarding compliance with Section 16 of the Exchange Act required by this item found under the heading *Governance Matters Section 16(a) Beneficial Ownership Reporting Compliance*

Information regarding AES s Financial Audit Committee found under the heading *The Committees of the Board Financial Audit Committee (the Audit Committee)*

Certain information regarding executive officers required by this Item is set forth as a supplementary item in Part I hereof (pursuant to Instruction 3 to Item 401(b) of Regulation S-K). The other information required by this Item, to the extent not included above, will be contained in our Proxy Statement for the 2010 Annual Meeting of Shareholders and is hereby incorporated by reference.

ITEM 11. EXECUTIVE COMPENSATION

The following information is contained in the 2010 Proxy Statement and is incorporated by reference: the information regarding executive compensation contained under the heading *Compensation Discussion and Analysis* and the Compensation Committee Report on Executive Compensation under the heading Report of the *Compensation Committee.*

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

(a) Security Ownership of Certain Beneficial Owners.

See the information contained under the caption Security Ownership of Certain Beneficial Owners, Directors, and Executive Officers of the Proxy Statement for the 2010 Annual Meeting of Shareholders of the Registrant, which information is incorporated herein by reference.

(b) Security Ownership of Directors and Executive Officers.

See the information contained under the caption Security Ownership of Certain Beneficial Owners, Directors, and Executive Officers of the Proxy Statement for the 2010 Annual Meeting of Shareholders of the Registrant, which information is incorporated herein by reference.

(c) Changes in Control.

None.

(d) Securities Authorized for Issuance under Equity Compensation Plans.

254

Table of Contents

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 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information regarding related party transactions required by this item is included in the 2010 Proxy Statement found under the headings Transactions with Related Persons, Proposal I: Election of Directors and The Committees of the Board are incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information concerning principal accountant fees and services included in the 2010 Proxy Statement contained under the heading Information Regarding The Independent Registered Public Accounting Firm s Fees, Services and Independence is incorporated by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements.

(b) Exhibits.

3.1	Sixth Restated Certificate of Incorporation of The AES Corporation is incorporated by reference to Exhibit 3.1 of the Company s Form 10-K for the year ended December 31, 2008.
3.2	By-Laws of The AES Corporation, as amended and incorporated herein by reference to Exhibit 3.1 of the Company s Form 8-K filed on August 11, 2009.
4	There are numerous instruments defining the rights of holders of long-term indebtedness of the Registrant and its consolidated subsidiaries, none of which exceeds ten percent of the total assets of the Registrant and its subsidiaries on a consolidated basis. The Registrant hereby agrees to furnish a copy of any of such agreements to the Commission upon request. Since these documents are not required filings under Item 601 of Regulation S-K, the Company has elected to file certain of these documents as Exhibits 4(a) 4(o).
4.(a)	Junior Subordinated Indenture, dated as of March 1, 1997, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association (formerly known as The First National Bank of Chicago) is incorporated by reference to Exhibit 4.(a) of the Company s Form 10-K for the year ended December 31, 2008.
4.(b)	Third Supplemental Indenture, dated as of October 14, 1999, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association is incorporated by reference to Exhibit 4.(b) of the Company s Form 10-K for the year ended December 31, 2008.
4.(c)	Senior Indenture, dated as of December 8, 1998, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association (formerly known as The First National Bank of Chicago) is incorporated by reference to Exhibit 4.01 of the Company s Form 8-K filed on December 11, 1998.
4.(d)	Form of Second Supplemental Indenture, dated as of June 11, 1999, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association (formerly known as The First National Bank of Chicago) is incorporated by reference to Exhibit 4.01 of the Company s Form 8-K filed on June 11, 1999.
4.(e)	Third Supplemental Indenture, dated as of September 12, 2000, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association is incorporated by reference to Exhibit 4.(e) of the Company s Form 10-K for the year ended December 31, 2008.
4.(f)	Form of Fifth Supplemental Indenture, dated as of February 9, 2001, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association is incorporated by reference to Exhibit 4.1 of the Company s Form 8-K filed on February 8, 2001.

4.(g)	Form of Sixth Supplemental Indenture, dated as of February 22, 2001, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association is incorporated by reference to Exhibit 4.1 of the Company s Form 8-K filed on February 21, 2001.
4.(h)	Ninth Supplemental Indenture, dated as of April 3, 2003, between The AES Corporation and Wells Fargo Bank, National Association (as successor by consolidation to Wells Fargo Bank Minnesota, National Association) is incorporated by reference to Exhibit 4.6 of the Company s Form S-4 filed on December 7, 2007.
4.(i)	Form of Tenth Supplemental Indenture, dated as of February 13, 2004, between The AES Corporation and Wells Fargo Bank, National Association (as successor by consolidation to Wells Fargo Bank Minnesota, National Association) is incorporated by reference to Exhibit 4.1 of the Company s Form 8-K filed on February 13, 2004.
4.(j)	Eleventh Supplemental Indenture, dated as of October 15, 2007, between The AES Corporation and Wells Fargo Bank, National Association is incorporated by reference to Exhibit 4.7 of the Company s Form S-4 filed on December 7, 2007.
4.(k)	Twelfth Supplemental Indenture, dated as of October 15, 2007, between The AES Corporation and Wells Fargo Bank, National Association is incorporated by reference to Exhibit 4.8 of the Company s Form S-4 filed on December 7, 2007.
4.(l)	Thirteenth Supplemental Indenture, dated as of May 19, 2008, between The AES Corporation and Wells Fargo Bank, National Association is incorporated by reference to Exhibit 4.(l) of the Company s Form 10-K for the year ended December 31, 2008.
4.(m)	Fourteenth Supplemental indenture, dated as of April 2, 2009, between The AES Corporation and Wells Fargo Bank, National Association is incorporated herein by reference to Exhibit 99.1 of the Company s Form 8-K filed on April 2, 2009.
4.(n)	Senior Indenture, dated as of May 8, 2003, between The AES Corporation and Wells Fargo Bank, National Association (as successor by consolidation to Wells Fargo Bank Minnesota, National Association) is incorporated by reference to Exhibit 4.(m) of the Company s Form 10-K for the year ended December 31, 2008.
4.(o)	First Supplemental Indenture, dated as of May 28, 2008, between The AES Corporation and Wells Fargo Bank, National Association is incorporated by reference to Exhibit 4.(n) of the Company s Form 10-K for the year ended December 31, 2008.
10.1	The AES Corporation Profit Sharing and Stock Ownership Plan are incorporated herein by reference to Exhibit 4(c)(1) of the Registration Statement on Form S-8 (Registration No. 33-49262) filed on July 2, 1992.
10.2	The AES Corporation Incentive Stock Option Plan of 1991, as amended, is incorporated herein by reference to Exhibit 10.30 of the Company s Form 10-K for the year ended December 31, 1995.
10.3	Applied Energy Services, Inc. Incentive Stock Option Plan of 1982 is incorporated herein by reference to Exhibit 10.31 of the Registration Statement on Form S-1 (Registration No. 33-40483).
10.4	Deferred Compensation Plan for Executive Officers, as amended, is incorporated herein by reference to Exhibit 10.32 of Amendment No. 1 to the Registration Statement on Form S-1(Registration No. 33-40483).
10.5	Deferred Compensation Plan for Directors is incorporated herein by reference to Exhibit 10.9 of the Company s Form 10-Q for the quarter ended March 31, 1998.
10.6	The AES Corporation Stock Option Plan for Outside Directors as amended is incorporated herein by reference to Appendix C of the Registrant s 2003 Proxy Statement filed on March 25, 2003.

10.7	The AES Corporation Supplemental Retirement Plan is incorporated herein by reference to Exhibit 10.63 of the Company s Form 10-K for the year ended December 31, 1994.
10.7A	Amendment to The AES Corporation Supplemental Retirement Plan, dated March 13, 2008 is incorporated herein by reference to Exhibit 10.9.A of the Company s Form 10-K for the year ended December 31, 2007.
10.8	The AES Corporation 2001 Stock Option Plan is incorporated herein by reference to Exhibit 10.12 of the Company s Form 10-K for the year ended December 31, 2000.
10.9	Second Amended and Restated Deferred Compensation Plan for Directors is incorporated herein by reference to Exhibit 10.13 of the Company s Form 10-K for the year ended December 31, 2000.
10.10	The AES Corporation 2001 Non-Officer Stock Option Plan is incorporated herein by reference to Exhibit 10.12 of the Company s Form 10-K for the year ended December 31, 2002.
10.10A	Amendment to the 2001 Stock Option Plan and 2001 Non-Officer Stock Option Plan, dated March 13, 2008 is incorporated herein by reference to Exhibit 10.12.A of the Company s Form 10-K for the year ended December 31, 2007.
10.11	The AES Corporation 2003 Long Term Compensation Plan, as amended and restated on April 24, 2008, is incorporated herein by reference to Exhibit 10.1 of the Company s Form 8-K filed on April 24, 2008.
10.11.A	Form of Nonqualified Stock Option Award Agreement Pursuant to the AES Corporation 2003 Long Term Compensation Plan is incorporated by reference to Exhibit 10.13A to the Annual Report on Form 10-K of the Registrant for the year ended December 31, 2004.*
10.11.B	Form of Performance Unit Award Agreement Pursuant to The AES Corporation 2003 Long Term Compensation Plan is incorporated by reference to Exhibit 10.13B to the Annual Report on Form 10-K of the Registrant for the year ended December 31, 2004.*
10.11.C	Form of Restricted Stock Unit Award Agreement Pursuant to The AES Corporation 2003 Long Term Compensation Plan is incorporated by reference to Exhibit 10.13C to the Annual Report on Form 10-K of the Registrant for the year ended December 31, 2004.*
10.12	The AES Corporation Amended and Restated Employment Agreement with Paul Hanrahan is incorporated herein by reference to Exhibit 99.1 of the Company s Form 8-K filed on December 31, 2008.
10.13	The AES Corporation Amended and Restated Employment Agreement with Victoria D. Harker is incorporated herein by reference to Exhibit 99.2 of the Company s Form 8-K filed on December 31, 2008.
10.14	The AES Corporation Employment Agreement with Andres Gluski is incorporated herein by reference to Exhibit 99.3 of the Company s Form 8-K filed on December 31, 2008.
10.15	The AES Corporation Restoration Supplemental Retirement Plan, as amended and restated, dated December 29, 2008 is incorporated by reference to Exhibit 10.15 of the Company s Form 10-K for the year ended December 31, 2008.
10.16	The AES Corporation International Retirement Plan, as amended and restated on December 29, 2008 is incorporated by reference to Exhibit 10.16 of the Company s Form 10-K for the year ended December 31, 2008.
10.17	The AES Corporation Severance Plan, as amended and restated on December 29, 2008 is incorporated by reference to Exhibit 10.17 of the Company s Form 10-K for the year ended December 31, 2008.
10.18	The AES Corporation Performance Incentive Plan, as amended and restated, dated December 29, 2008 is incorporated by reference to Exhibit 10.18 of the Company s Form 10-K for the year ended December 31, 2008.

10.19	Second Amended and Restated Pledge Agreement dated as of December 12, 2002 between AES EDC Funding II, L.L.C. and Citicorp USA, Inc., as Collateral Agent is incorporated herein by reference to Exhibit 99.3 of the Company s Form 8-K filed on December 17, 2002.
10.20	Fourth Amended And Restated Credit And Reimbursement Agreement dated as of July 29, 2008 among The AES Corporation, a Delaware corporation, the Subsidiary Guarantors listed therein, the Banks listed on the signature pages thereof, Citigroup Global Markets Inc., as Lead Arranger and Book Runner, Banc of America Securities LLC, as Lead Arranger and Book Runner and as Co-Syndication Agent, Deutsche Bank Securities Inc, as Lead Arranger and Book Runner, Union Bank of California, N.A., as Co-Syndication Agent and as Lead Arranger and Book Runner and as Syndication Agent, Lehman Commercial Paper Inc., as Co-Documentation Agent, UBS Securities LLC, as Co-Documentation Agent, Société Générale, as Co-Documentation Agent, Credit Lyonnais New York Branch, as Co-Documentation Agent, Citicorp USA, Inc., as Administrative Agent for the Bank Parties and Citibank, N.A., as Collateral Agent for the Bank Parties is incorporated herein by reference to Exhibit 10.2 of the Company s Form 8-K filed on July 31, 2008.
10.20.A	Appendix I, Revolving Credit Loan Facility pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.A of the Company s Form 10-Q for the period ended June 30, 2009.
10.20.B	Appendix II, Initial Term Loan Facility pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.B of the Company s Form 10-Q for the period ended June 30, 2009.
10.20.C	Appendix III, Existing Letters of Credit pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.C of the Company s Form 10-Q for the period ended June 30, 2009.
10.20.D	Schedule I, Pledged Subsidiaries pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.D of the Company s Form 10-Q for the period ended June 30, 2009.
10.20.E	Schedule II, Assigned Agreements pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.E of the Company s Form 10-Q for the period ended June 30, 2009.
10.20.F	Schedule III, Non-Pledged Subsidiaries pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.F of the Company s Form 10-Q for the period ended June 30, 2009.
10.20.G	Schedule IV, Excluded AES Entities pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.G of the Company s Form 10-Q for the period ended June 30, 2009.
10.20.H	Schedule 5.15, Existing Agreements with Affiliates pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.H of the Company s Form 10-Q for the period ended June 30, 2009.
10.20.I	Schedule V, Qualified Holding Companies pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.I of the Company s Form 10-Q for the period ended June 30, 2009.
10.20.J	Schedule VI, Existing Debt pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.J of the Company s Form 10-Q for the period ended June 30, 2009.
10.20.K	Schedule VII, Revolving Fronting Banks pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.K of the Company s Form 10-Q for the period ended June 30, 2009.

10.20.L	Exhibit A-1, Form of Revolving Credit Loan Note pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.L of the Company s Form 10-Q for the period ended June 30, 2009.
10.20.M	Exhibit A-2, Form of Term Loan Note pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.M of the Company s Form 10-Q for the period ended June 30, 2009.
10.20.N	Exhibit B-1, Form of Opinion of the General Counsel of the Borrower pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to Exhibit 10.1.N of the Company s Form 10-Q for the period ended June 30, 2009.
10.20.O	Exhibit B-2, Form of Opinion of Davis Polk & Wardwell, Special Counsel for the Borrower pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to the Company s Form 10-Q for the period ended June 30, 2009.
10.20.P	Exhibit B-3, Form of Opinion of Special Counsel for certain Subsidiaries of the Borrower pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to the Company s Form 10-Q for the period ended June 30, 2009.
10.20.Q	Exhibit B-4, Form of Opinion of Morris, Nichols, Arsht & Tunnell, Delaware counsel for the Borrower pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to the Company s Form 10-Q for the period ended June 30, 2009.
10.20.R	Exhibit B-5, Form of Opinion of Maples and Calder, Cayman Islands counsel for the Borrower pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to the Company s Form 10-Q for the period ended June 30, 2009.
10.20.S	Exhibit B-6, Form of Opinion of Conyers Dill & Pearman, British Virgin Islands counsel for the Borrower pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to the Company s Form 10-Q for the period ended June 30, 2009.
10.20.T	Exhibit B-7, Form of Opinion of Shearman & Sterling, Special Counsel for the Agent pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to the Company s Form 10-Q for the period ended June 30, 2009.
10.20.U	Exhibit C-1, Form of Revolving Credit Loan Facility Assignment and Assumption Agreement pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to the Company s Form 10-Q for the period ended June 30, 2009.
10.20.V	Exhibit C-2, Form of Term Loan Facility Assignment and Assumption Agreement pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to the Company s Form 10-Q for the period ended June 30, 2009.
10.20.W	Exhibit C-3, Form of Third Party Fronting Bank Assignment and Assumption Agreement pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to the Company s Form 10-Q for the period ended June 30, 2009.
10.20.X	Exhibit D, Form of Revolving Fronting Bank Agreement pursuant to the Fourth Amended and Restated Credit Agreement is incorporated herein by reference to the Company s Form 10-Q for the period ended June 30, 2009.
10.20A	Amendment No. 1 to the Fourth Amended and Restated Credit and Reimbursement Agreement dated as of March 26, 2009 among the Company, the subsidiary guarantors, Citicorp USA, Inc., as Administrative Agent, Citibank N.A. as Collateral Agent and various lenders named therein is incorporated herein by reference to Exhibit 10.1 of the Company s Form 8-K filed on March 26, 2009.
10.21	The definitive agreement between Petroleos de Venezuela S.A. and The AES Corporation and AES Shannon Holdings B.V. dated February 15, 2007 is incorporated herein by reference to Exhibit 99.1 of the Company s Form 8-K filed on February 27, 2007.

Table of Contents

10.22	Collateral Trust Agreement dated as of December 12, 2002 among The AES Corporation, AES International Holdings II, Ltd., Wilmington Trust Company, as corporate trustee and Bruce L. Bisson, an individual trustee is herein incorporated by reference to Exhibit 4.2 of the Company s Form 8-K filed on December 17, 2002.
10.23	Security Agreement dated as of December 12, 2002 made by The AES Corporation to Wilmington Trust Company, as corporate trustee and Bruce L. Bisson, as individual trustee is herein incorporated by reference to Exhibit 4.3 of the Company s Form 8-K filed on December 17, 2002.
10.24	Charge Over Shares dated as of December 12, 2002 between AES International Holdings II, Ltd. and Wilmington Trust Company, as corporate trustee and Bruce L. Bisson, as individual trustee is herein incorporated by reference to Exhibit 4.4 of the Company s Form 8-K filed on December 17, 2002.
10.25	The AES Corporation Severance Agreement with William Luraschi, dated May 14, 2008 is incorporated by reference to Exhibit 10.28 of the Company s Form 10-K for the year ended December 31, 2008.
10.26	The AES Corporation Severance Agreement with Jay Kloosterboer, dated November 26, 2008 is incorporated by reference to Exhibit 10.29 of the Company s Form 10-K for the year ended December 31, 2008.
10.27	The AES Corporation Severance Agreement with David Gee, dated February 26, 2009 is incorporated by reference to Exhibit 10.30 of the Company s Form 10-K for the year ended December 31, 2008.
10.28	Stock Purchase Agreement between The AES Corporation and Terrific Investment Corporation dated November 6, 2009 is incorporated herein by reference to Exhibit 10.1 of the Company s Form 8-K filed on November 11, 2009.
12	Statement of computation of ratio of earnings to fixed charges (filed herewith).
16	Letter from Deloitte & Touche LLP addressed to the Securities and Exchange Commission relating to auditor dismissal dated December 13, 2007 is incorporated by reference to Exhibit 16.1 of the Company s Form 8-K filed on December 13, 2007.
21	Subsidiaries of The AES Corporation (filed herewith).
23.1	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP (filed herewith).
23.2	Consent of Independent Registered Public Accounting Firm, Deloitte & Touche LLP (filed herewith).
24	Power of Attorney (filed herewith).
31.1	Rule13a-14(a)/15d-14(a) Certification of Paul Hanrahan (filed herewith).
31.2	Rule 13a-14(a)/15d-14(a) Certification of Victoria D. Harker (filed herewith).
32.1	Section 1350 Certification of Paul Hanrahan (filed herewith).
32.2	Section 1350 Certification of Victoria D. Harker (filed herewith).
101	The following materials from The AES Corporation s Annual Report on Form 10-K for the year ended December 31, 2009 formatted in Extensible Business Reporting Language (XBRL): (i) the Consolidated Statements of Operations, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Statements of Changes in Equity, (v) the Notes to the Consolidated Financial Statements, tagged as block text.

(c) Schedules

Schedule I Condensed Financial Information of Registrant

Schedule II Valuation and Qualifying Accounts

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	THE AES CORPORATION	
	(Company)	
Date: February 25, 2010	By:	/s/ Paul Hanrahan
	Name:	**Paul Hanrahan President,** ***Chief Executive Officer***

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the Company and in the capacities and on the dates indicated.

Name	Title	Date
* **Paul Hanrahan**	President, Chief Executive Officer (Principal Executive Officer) and Director	February 25, 2010
* **Samuel W. Bodman, III**	Director	February 25, 2010
* **Tarun Khanna**	Director	February 25, 2010
* **John A. Koskinen**	Director	February 25, 2010
* **Philip Lader**	Director	February 25, 2010
* **John B. Morse**	Director	February 25, 2010
* **Sandra O. Moose**	Director	February 25, 2010
* **Philip A. Odeen**	Chairman of the Board and Lead Independent Director	February 25, 2010
* **Charles O. Rossotti**	Director	February 25, 2010
*	Director	February 25, 2010

Sven Sandstrom		
/s/ Victoria D. Harker **Victoria D. Harker**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2010
/s/ Mary Wood **Mary Wood**	Vice President and Controller (Principal Accounting Officer)	February 25, 2010
*By: /s/ Brian A. Miller **Attorney-in-fact**		February 25, 2010

262

THE AES CORPORATION AND SUBSIDIARIES

INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedules other than those listed above are omitted as the information is either not applicable, not required, or has been furnished in the financial statements or notes thereto included in Item 8 hereof.

Table of Contents

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF REGISTRANT

UNCONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 628	$ 200
Restricted cash	9	13
Accounts and notes receivable from subsidiaries	514	710
Deferred income taxes	27	19
Prepaid expenses and other current assets	34	43
Total current assets	1,212	985
Investment in and advances to subsidiaries and affiliates	8,639	7,659
Office Equipment:		
Cost	86	66
Accumulated depreciation	(47)	(34)
Office equipment, net	39	32
Other Assets:		
Deferred financing costs (net of accumulated amortization of $76 and $89, respectively)	72	67
Deferred income taxes	516	311
Other assets	25	3
Total other assets	613	381
Total	$ 10,503	$ 9,057
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	5	
Accrued and other liabilities	208	210
Senior notes payable current portion	214	154
Total current liabilities	427	364
Long-term Liabilities:		
Term loan	200	200
Senior notes payable	4,584	4,277
Junior subordinated notes and debentures payable	517	517
Other long-term liabilities	100	30
Total long-term liabilities	5,401	5,024
Stockholders equity:		
Common stock	7	7
Additional paid-in capital	6,868	6,832
Retained earnings (deficit)	650	(8)
Accumulated other comprehensive loss	(2,724)	(3,018)
Treasury stock	(126)	(144)

Total stockholders equity	4,675	3,669
Total	$ 10,503	$ 9,057

See Notes to Schedule I

S-2

Table of Contents

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF REGISTRANT

STATEMENTS OF UNCONSOLIDATED OPERATIONS

	For the Years Ended December 31		
	2009	2008	2007
		(in millions)	
Revenues from subsidiaries and affiliates	$ 39	$ 36	$ 32
Equity in earnings of subsidiaries and affiliates	983	2,019	588
Interest income	131	173	155
General and administrative expenses	(218)	(264)	(411)
Interest expense	(485)	(516)	(471)
Income (loss) before income taxes	450	1,448	(107)
Income tax benefit (expense)	208	(215)	12
Net income (loss)	$ 658	$ 1,233	$ (95)

See Notes to Schedule I

S-3

Table of Contents

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF REGISTRANT

STATEMENTS OF UNCONSOLIDATED CASH FLOWS

(IN MILLIONS)

	For the Years Ended December 31,		
	2009	**2008**	**2007**
Net cash provided by operating activities	$ 178	$ 863	$ 213
Investing Activities:			
Proceeds from asset sales, net of expenses			55
Investment in and advances to subsidiaries	(452)	(1,098)	(899)
Acquisitions-net of cash acquired	(5)	(95)	(3)
Return of capital	166	89	265
Increase in restricted cash	4	2	(7)
Additions to property, plant and equipment	(8)	(23)	(199)
Net cash used in investing activities	(295)	(1,125)	(788)
Financing Activities:			
Borrowings of notes payable and other coupon bearing securities	503	625	2,000
Repayments of notes payable and other coupon bearing securities	(154)	(1,037)	(1,315)
Loans from subsidiaries	205	90	534
Proceeds from issuance of common stock	14	28	58
Purchase of treasury stock		(143)	
Payments for deferred financing costs	(23)	(14)	(27)
Net cash (used in) provided by financing activities	545	(451)	1,250
Increase (decrease) in cash and cash equivalents	428	(713)	675
Cash and cash equivalents, beginning	200	913	238
Cash and cash equivalents, ending	$ 628	$ 200	$ 913
Schedule of non-cash investing and financing activities:			
Cash payments for interest, net of amounts capitalized	$ 410	$ 469	$ 416
Cash payments for income taxes, net of refunds	$	$	$

See Notes to Schedule I

S-4

Table of Contents

THE AES CORPORATION

SCHEDULE I

NOTES TO SCHEDULE I

1. Application of Significant Accounting Principles

Accounting for Subsidiaries and Affiliates The AES Corporation (the Company) has accounted for the earnings of its subsidiaries on the equity method in the unconsolidated financial information.

Revenue Construction management fees earned by the parent from its consolidated subsidiaries are eliminated.

Income Taxes Effective January 1, 2007, the Company adopted the provisions set forth in the accounting guidance for uncertainty in income taxes. Under the guidance, positions taken on the Company s income tax return which satisfy a more-likely-than-not threshold will be recognized in the financial statements. The unconsolidated income tax expense or benefit computed for the Company reflects the tax assets and liabilities of the Company on a stand-alone basis and the effect of filing a consolidated U.S. income tax return with certain other affiliated companies.

Accounts and Notes Receivable from Subsidiaries such amounts have been shown in current or long-term assets based on terms in agreements with subsidiaries, but payment is dependent upon meeting conditions precedent in the subsidiary loan agreements.

Selected Unconsolidated Balance Sheet Data:

	December 31, 2009	December 31, 2008
	(in millions)	
Assets		
Investment in and advances to subsidiaries and affiliates	$ 8,639	$ 7,659
Deferred income taxes	$ 516	$ 311
Total other assets	$ 613	$ 381
Total assets	$ 10,503	$ 9,057
Liabilities & Stockholders Equity		
Other long-term liabilities	$ 100	$ 30
Total long-term liabilities	$ 5,401	$ 5,024
Additional paid-in capital	$ 6,868	$ 6,832
Accumulated loss	$ 650	$ (8)
Accumulated other comprehensive loss	$ (2,724)	$ (3,018)
Total stockholders equity	$ 4,675	$ 3,669
Total liabilities & stockholders equity	$ 10,503	$ 9,057

Selected Unconsolidated Operations Data:

	For the Year Ended December 31,		
	2009	2008	2007
		(in millions)	
Equity in earnings of subsidiaries and affiliates	$ 983	$ 2,019	$ 588
Income (loss) before cumulative effect of change in accounting principle	$ 450	$ 1,448	$ (107)
Income (loss) before income taxes	$ 450	$ 1,448	$ (107)
Income tax benefit	$ 208	$ (215)	$ 12
Net income (loss) attributable to The AES Corporation	$ 658	$ 1,233	$ (95)

S-5

Table of Contents

2. Notes Payable

RECOURSE DEBT	Interest Rate	Maturity	December 31, 2009	December 31, 2008
			(in millions)	
Senior Unsecured Note	9.50%	2009	$	$ 154
Senior Unsecured Note	9.375%	2010	214	214
Senior Secured Term Loan	LIBOR + 1.75%	2011	200	200
Senior Unsecured Note	8.875%	2011	129	129
Senior Unsecured Note	8.375%	2011	139	124
Second Priority Senior Secured Note	8.75%	2013	690	690
Senior Unsecured Note	7.75%	2014	500	500
Senior Unsecured Note	7.75%	2015	500	500
Senior Unsecured Note	9.75%	2016	535	
Senior Unsecured Note	8.00%	2017	1,500	1,500
Senior Unsecured Note	8.00%	2020	625	625
Term Convertible Trust Securities	6.75%	2029	517	517
Unamortized discounts			(34)	(5)
SUBTOTAL			$ 5,515	$ 5,148
Less: Current maturities			(214)	(154)
Total			$ 5,301	$ 4,994

FUTURE MATURITIES OF DEBT Recourse debt as of December 31, 2009 is scheduled to reach maturity as set forth in the table below:

December 31,	Annual Maturities (in millions)
2010 .	$ 214
2011 .	468
2012 .	
2013 .	690
2014 .	497
Thereafter	3,646
Total recourse debt	$ 5,515

3. Dividends from Subsidiaries and Affiliates

Cash dividends received from consolidated subsidiaries and from affiliates accounted for by the equity method were as follows:

	2009	2008	2007
		(in millions)	
Subsidiaries	$ 948	$ 738	$ 737
Affiliates	$ 60	$ 61	$ 21

S-6

4. Guarantees and Letters of Credit

GUARANTEES In connection with certain of its project financing, acquisition, and power purchase agreements, the Company has expressly undertaken limited obligations and commitments, most of which will only be effective or will be terminated upon the occurrence of future events. These obligations and commitments, excluding those collateralized by letter of credit and other obligations discussed below, were limited as of December 31, 2009, by the terms of the agreements, to an aggregate of approximately $410 million representing 31 agreements with individual exposures ranging from less than $1 million up to $53 million.

LETTERS OF CREDIT At December 31, 2009, the Company had $204 million in letters of credit outstanding representing 26 agreements with individual exposures ranging from less than $1 million up to $120 million, which operate to guarantee performance relating to certain project development and construction activities and subsidiary operations. During 2009, the Company paid letter of credit fees ranging from 1.63% to 13.34% per annum on the outstanding amounts.

Table of Contents

THE AES CORPORATION

SCHEDULE II

VALUATION AND QUALIFYING ACCOUNTS

(IN MILLIONS)

	Balance at Beginning of the period	Charged to Cost and Expense	Amounts Written off	Translation Adjustment	Balance at the End of the Period
Allowance for accounts receivables					
(current and noncurrent)					
Year ended December 31, 2007 .	$ 331	$ 179	$ (192)	$ 53	$ 371
Year ended December 31, 2008 .	371	127	(65)	(100)	333
Year ended December 31, 2009 .	333	109	(117)	67	392

S-8