AES CORP
Form 10-K
April 04, 2006

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2005

COMMISSION FILE NUMBER 0-19281

The AES Corporation

(Exact name of registrant as specified in its charter)

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

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

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

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

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

None

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

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

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

Indicate by check mark 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 filter, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x Accelerated filer o Non-accelerated filer o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates on June 30, 2005 (based on the closing sale price of $16.38 of the Registrant s Common Stock, as reported by the New York Stock Exchange on such date) was approximately $10.7 billion.

The number of shares outstanding of the Registrant s Common Stock, par value $0.01 per share, on March 3, 2006, was 657,601,448.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information from the registrant s Proxy Statement for the Annual Meeting of Stockholders to be held on May 11, 2006 is hereby incorporated by reference into Part III hereof.

THE AES CORPORATION
FISCAL YEAR 2005 FORM 10-K

TABLE OF CONTENTS TO BE UPDATED

PART I

The AES Corporation, including all its subsidiaries and affiliates are collectively referred to herein as AES the Company, us or we.

RESTATEMENT OF CONSOLIDATED FINANCIAL STATEMENTS

Subsequent to filing its restated annual report on Form 10-K/A with the Securities Exchange Commission on January 19, 2006, the Company discovered its previously issued restated consolidated financial statements included certain errors in accounting for derivative instruments and hedging activities, minority interest expense and income taxes. The errors in accounting for derivative instruments and hedging activities resulted in differences in previously issued consolidated interim financial statements for certain quarterly periods in 2004 sufficient to require restatement of prior period interim results. The errors in accounting for income taxes and minority interest expense required restatement of previously issued consolidated annual financial statements.

As a result of evaluating these adjustments, the Company reduced its stockholders equity by $12 million as of January 1, 2003 as the cumulative effect of the correction of errors for all periods proceeding January 1, 2003, and restated its consolidated statements of operations and cash flows for the years ended December 31, 2004 and 2003 and its consolidated balance sheet as of December 31, 2004.

The restatement adjustments resulted in an increase to previously reported net income of $6 million for the year ended December 31, 2004 and in a decrease to previously reported net income of $17 million for the year ended December 31, 2003. There was no impact on gross margin or net cash flow from operating activities of the Company for any years presented. Based upon management s review it has been determined that these errors were inadvertent and unintentional. The errors relate to the following areas:

A. Accounting for Derivative Instruments and Hedging Activities

The Company determined that it failed to perform adequate on-going effectiveness testing for three interest rate cash flow hedges and one foreign currency cash flow hedge during 2004 as required by SFAS No. 133. As a result, the Company should have discontinued hedge accounting and recognized changes in the fair value of the derivative instruments in earnings prospectively from the last valid effectiveness assessment until the earlier of either (1) the expiration of the derivative instrument or (2) the re-designation of the derivative instrument as a hedging activity.

The net impact related to the correction of these errors to previously reported net income resulted in a decrease of $4 million and an increase of $2 million for the years ending December 31, 2004 and 2003, respectively.

B. Income Tax and Minority Interest Adjustments

As a result of the Company s year end closing review process, the Company discovered certain other errors related to the recording of income tax liabilities and minority interest expense. The adjustments primarily include:

- An increase in income tax expense related to the recording of certain historical withholding tax liabilities at one of our El Salvador subsidiaries;

- An increase in minority interest expense related to a correction of the allocation of income tax expense to minority shareholders. This allocation pertained to certain deferred tax adjustments recorded in the original restatement at one of our Brazilian generating companies. In addition, minority interest expense was also corrected at this subsidiary as a result of identifying differences arising from a more comprehensive reconciliation of prior year statutory financial records to U.S. GAAP financial statements;

- A reduction of 2004 income tax expense related to adjustments derived from 2004 income tax returns filed in 2005.

The net impact related to the correction of these errors to previously reported net income resulted in an increase of $10 million and a decrease of $19 million for the years ending December 31, 2004 and 2003, respectively. In addition, the Company restated stockholders equity as of January 1, 2003 by $12 million as a correction for these errors in all periods preceding January 1, 2003.

C. Other Balance Sheet Reclassifications

Certain other balance sheet reclassifications were recorded at December 31, 2004 including a $45 million reclassification which reduced Accounts Receivables and increased Other Current Assets (regulatory assets).

ITEM 1. BUSINESS

Overview

AES, a global power company formed in 1981, is a Delaware corporation holding company that through its subsidiaries, operates a portfolio of electricity generation and distribution businesses in 25 countries on five continents.

We operate in two types of businesses within the power sector: first, we generate power for sale to utilities and other wholesale customers; second, we operate utilities that distribute power to retail, commercial, industrial and governmental customers typically through integrated transmission and distribution systems. Each type of business generates approximately one half of the Company s revenues.

The generation and distribution of electricity are essential services required in all industrialized societies. We are committed to helping meet the world s need for electricity by supplying power from our existing portfolio, as well as by growing our portfolio through the development and construction of new power plants and through selective acquisitions. We believe that being a large participant in the global power sector gives us the best chance to accomplish our goals. Some of the benefits of being a large organization are the ability to take advantage of scale and to have the resources to develop better operating and management practices to increase overall Company efficiency and productivity. By maintaining a substantial geographic footprint, we are well positioned to pursue opportunities in those markets with favorable characteristics for new investment, namely those having a large and growing need for power. We target specific countries or major geographic regions as areas of primary focus, and seek to build sufficient knowledge and experience in order to increase our ability to successfully compete, and ultimately grow our businesses, in those targeted markets. We believe that this approach also allows us to more efficiently identify and manage the risks inherent in our business.

In addition to our primary business of operating a global power portfolio, we also are engaged in a exploring and promoting a set of related activities that include alternative energy businesses such as wind generation, the supply of liquefied natural gas to certain targeted North American markets, the production of greenhouse gas reduction activities and related industries involving environmental issues and the application of new energy technologies. At present, these initiatives represent growth opportunities for us but currently account for a de minimus amount of revenue and earnings.

Our financial results are reported within three business segments: Contract Generation, Competitive Supply and Regulated Utilities.

Our generation business encompasses our contract generation and competitive supply segments. Performance drivers for our contract generation and competitive supply segments include plant reliability and fuel and fixed cost management. Growth is largely tied to securing new power purchase agreements and expanding capacity. The contract generation and competitive supply segments contributed 37% and 11% of revenues, respectively, for the year 2005.

Performance drivers for our regulated utilities segment include providing reliable service, managing working capital, obtaining tariff adjustments and appropriate regulatory treatment for new investments and, in developing countries, reduction of commercial and technical losses. The regulated utilities segment contributed 52% of revenues for the year 2005. The revenues and earnings growth of both our generation and utility businesses vary with changes in electricity demand.

Our management structure is divided into four regions: North America; Latin America; Europe, Middle East and Africa (EMEA); and Asia, each led by a regional president who reports directly to the Chief Executive Officer (CEO). This structure allows us to place senior leaders and resources closer to our businesses around the world to further improve operating performance and integrate operations and development on a more localized level. This helps us leverage regional market trends to enhance our competitiveness and identify and capitalize on key business development opportunities across our lines of business. The Company also maintains a corporate Business Development group which manages large scale transactions such as mergers and acquisitions, and portfolio management, as well as targeted strategic initiatives such as the creation of an alternative energy business.

Operating Segments

See Note 21 to the Consolidated Financial Statements included in Item 8 of this Form 10-K for additional financial information about our business segments as well as information about our geographic operations.

Contract Generation

Our contract generation businesses own and operate plants that sell electricity and related products to utilities or other wholesale customers under long-term contracts. Our contract generation facilities generally limit their exposure to commodity price risks, primarily electricity price volatility and frequently volume risk, by entering into power sales agreements of five years or longer for 75% or more of their output capacity. The remaining terms of these agreements range from 1 to 25 years. These facilities also generally enter into long-term agreements for most of their fuel supply requirements, or they may enter into tolling or pass through arrangements in which the counter-party directly assumes the risks associated with providing the necessary fuel and then markets the generated power. Through these types of contractual agreements, our contract generation businesses generally produce more predictable cash flows and earnings. The degree of predictability varies from business to business based on the degree to which their exposure is limited by the contracts they have negotiated with their buyers and fuel suppliers.

Our contract generation segment is comprised of our interests in 76 power generating facilities totaling approximately 23.0 gigawatts of capacity located in 17 countries. This includes minority interests in 28 power generation facilities totaling over 2.0 gigawatts of capacity. In addition, there are three plants under construction in three countries which, when completed, will add a total capacity of approximately 1.4 gigawatts to our contract generation segment. AES also operates, under either management or operations and maintenance agreements, 377 MW of wind generation facilities in the U.S. Of the 23.0 gigawatts of current operating capacity, 50% is derived from gas-fired facilities, 28% from coal-fired facilities, 13% from hydro facilities, 7% from oil-fired facilities, 2% from wind facilities, and less than 1% from biomass facilities.

In most of our contract generating businesses, a single customer contracts for most or all of a particular facility s generated power. To reduce the resulting counter-party credit risk, we seek to contract with creditworthy customers. We also seek to obtain sovereign government guarantees of the customer s obligations. However, we do business with many customers in many countries where neither the customer nor the government has investment grade ratings. We believe that locating our plants in different geographic areas helps to mitigate the effects of regional economic downturns, thereby offsetting some of the risks associated with operating in less developed countries. Additionally, in countries in which we own distribution companies, our contract generation businesses seek to contract with the distribution companies that we control.

Certain of our subsidiaries and affiliates are in various stages of developing and constructing new power plants (known as greenfield power plants or greenfield). Some have signed long-term contracts or made similar arrangements for the sale of electricity. During 2005, the Company made significant progress on important growth projects. Among these plants under construction, the Company s 120 MW Buffalo Gap wind power project in Texas began commercial operations in 2006. The Company s 1,200 MW gas-fired power plant in Cartagena, Spain is scheduled for completion in 2006. The Company s new 120 MW Los Vientos diesel-fired peaking facility which will serve the largest power market in Chile, is expected to be on-line in the second quarter of 2006. We currently believe that our costs related to these projects are recoverable but can provide no assurance that we will complete these projects and/or that these projects will reach commercial operation.

In the contract generation segment, we face most of our competition prior to the execution of a power sales agreement during the development phase of a project. Our competitors in this business include other independent power producers and equipment manufacturers, as well as various utilities and their affiliates. During the operational phase, we traditionally have faced limited competition in this segment due to the long-term nature of the generation contracts. However, since competitive power markets have been introduced and new market participants have been added, we will encounter increased competition in attracting new customers and maintaining our current customers as our existing contracts expire.

Competitive Supply

Our competitive supply businesses own and operate plants that sell electricity to wholesale customers in competitive markets. These plants typically sell into local power pools under short-term (less than one year) contracts or into daily spot markets. Demand can be affected by weather, electricity transmission constraints, fuel prices and competition. This business segment offers more varied sales, earnings and cash flows than our other segments.

In contrast to the contract generation segment discussed above, these facilities generally sell less than 75% of their output under long-term contracts. The prices at which these facilities sell electricity under short-term contracts and in the spot electricity markets are unpredictable and can be volatile. In addition, our operational results in this segment are more sensitive to the impact of market fluctuations in the price of natural gas, coal, oil and other fuels. These businesses also have more significant needs for working capital or credit to support their operations than our businesses in the contract generation segment.

Our competitive supply segment is comprised of 27 power generation facilities totaling approximately 13 gigawatts of capacity located in 7 countries. Of the total 13 gigawatts of current operating capacity, 59% is derived from coal-fired facilities, 8% from gas-fired facilities, 29% from hydro facilities, 2% from oil facilities, 1% from petroleum coke facilities and less than 1% from biomass facilities. In November 2005, we completed an output upgrade of the Alicura facility in Argentina, which resulted in an additional 10 MW of capacity.

The absence of long-term contracts makes future production volumes uncertain, which in turn makes it difficult to forecast the amount of fuel needed to support those volumes. As a result, competitive supply businesses are exposed to volume risk in connection with their purchases of natural gas, coal and other raw materials. Where appropriate, we have hedged a portion of our financial performance against the effects of fluctuations in energy commodity prices using such strategies as commodity forward contracts, futures, swaps and options.

Although we maintain credit policies with regard to our counterparties, there can be no assurance that ultimately they will be able to fulfill their contractual obligations. Volatility in electricity markets causes increases in credit risk, a decline in the number and quality of market participants with strong credit ratings and considerably less liquidity in energy markets.

We compete in this segment with numerous other independent power producers, energy marketers and traders, energy merchants, transmission and distribution providers and retail energy suppliers. Competitive factors in this segment include reliability, operational cost and third party credit requirements.

Regulated Utilities

Our regulated utilities business segment consists of 14 distribution companies in seven countries with approximately 11 million customers. Our regulated utilities aggregate approximately 7.0 gigawatts of generation capacity with annual sales of over 82 gigawatt hours. All of these companies maintain a monopoly franchise within a defined service area. This segment is composed of three integrated utilities, one located in the U.S. (Indianapolis Power & Light Company, or IPL), one in Venezuela (EDC) and one in Cameroon (AES SONEL) and electricity distribution businesses located in Argentina (EDELAP, EDEN and EDES), Brazil (AES Eletropaulo and AES Sul), El Salvador (CAESS, CLESA, DEUSEM and EEO), and Ukraine (Kievoblenergo and Rivneenergo). These utilities sell electricity under regulated tariff agreements and each has transmission and distribution capabilities; IPL, EDC, and AES SONEL also have generation plants. Our regulated utilities are subject to extensive regulation at multiple governmental levels relating to ownership, marketing, delivery and pricing of electricity and gas, with a focus on protecting customers. Regulated utilities revenues result primarily from retail electricity sales to customers under regulated tariff or concession agreements, long term electricity sale concessions granted by the appropriate governmental authorities and, to a lesser extent, from contractual agreements of varying lengths and provisions. Our three largest regulated utilities businesses (further described below), which account for approximately 67% of the gigawatt-hours distributed by our regulated utilities, are IPALCO Enterprises, Inc., AES Eletropaulo and EDC.

IPALCO Enterprises Inc. (IPALCO) is a holding company and its principal subsidiary is IPL. IPL is engaged in generating, transmitting, distributing and selling electric energy to approximately 460,000 customers in the city of Indianapolis and neighboring areas within the state of Indiana. IPL owns and operates four generation facilities. Two generating facilities are primarily 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 net generation winter capability is 3,370 MW and net summer capability is 3,252 MW. We acquired IPALCO in March 2001.

AES Eletropaulo has served the São Paulo, Brazil area for over 100 years and with over five million customers, is the largest electricity distribution company in the Americas in terms of customers. AES Eletropaulo s concession contract with the Brazilian National Electric Energy Agency (ANEEL), the government agency responsible for regulating the Brazilian electric industry, entitles AES Eletropaulo to distribute electricity in its service area for 30 years from the date of our acquisition in 1998. AES Eletropaulo s service territory consists of 24 municipalities in the greater São Paulo metropolitan area and adjacent regions that account for approximately 15% of Brazil s GDP, covering more than 5 million customers or 44% of the population in the State of São Paulo, Brazil.

EDC was founded in 1895 and is the largest private-sector electric utility in Venezuela serving approximately one million customers. EDC generates, transmits and distributes electricity to customers in metropolitan Caracas and its surrounding area. EDC s distribution area covers 5,176 square kilometers. EDC has an installed generating capacity of 2,616 MW. EDC commenced construction of a new 200 MW gas-fired generation plant. This project is expected to start-up in 2007 and will support continued demand growth at this regulated utility.

Electricity sales are made under regulated tariff agreements or under existing regulatory laws and provisions. For utilities located in developing countries, the local business environment also provides for significant opportunities to implement operating improvements that may stimulate growth in earnings and cash flow performance. These growth rates may be greater than those typically achievable in our other business segments and at utilities in more developed countries. Many of these businesses face challenges unique to developing countries including outdated equipment, significant electricity theft-related losses, cultural problems associated with customer safety and non-payment, emerging economies and potentially less stable governments or regulatory regimes.

The regulated utilities face relatively little direct competition due to significant barriers to entry which are present in these markets. In this segment, we primarily face competition in our efforts to acquire businesses. We compete against a number of other participants, some of which have greater financial resources, have been engaged in distribution related businesses for periods longer than we have, and have accumulated more significant portfolios. Relevant competitive factors include financial resources, governmental assistance, and access to non-recourse financing and regulatory restrictions. In certain locations, utilities 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. We can provide no assurance that deregulation will not adversely affect our regulated utilities future operations, cash flows and financial condition. The results of operations of our utilities business are sensitive to changes in economic growth and regulation (especially in emerging markets), abnormal weather conditions affecting each local market, as well as the success of the operational changes that have been implemented.

Facilities

The following tables present information with respect to the facilities in each of our three business segments. The amounts under Gross MW and Approximate Gigawatt Hours represent the gross amounts for each facility without regard to our percentage of ownership interest in the facility.

Contract Generation
(As of December 31, 2005)

Generation Facilities	Geographic Location	Dominant Fuel	Year of Acquisition or Commencement of Commercial Operations	Gross MW	AES Equity Interest (Percent Rounded)
North America					
Altamont	USA	Wind	2005	24	100
Altech III	USA	Wind	2005	25	100
Beaver Valley	USA	Coal	1985	125	100
Central Valley Delano	USA	Biomass	2001	57	100
Central Valley Mendota	USA	Biomass	2001	25	100
Condon	USA	Wind	2005	25	38
Hawaii	USA	Coal	1992	203	100
Hemphill	USA	Biomass	2001	16	67
Ironwood	USA	Gas	2001	710	100
Kingston(1)	Canada	Gas	1997	110	50
Mérida III	Mexico	Gas	2000	484	55
Placerita	USA	Gas	1989	115	100
Puerto Rico	USA	Coal	2002	454	100
Red Oak	USA	Gas	2002	832	100
Shady Point	USA	Coal	1991	320	100
Southland Alamitos	USA	Gas	1998	2,047	100
Southland Huntington Beach	USA	Gas	1998	904	100
Southland Redondo Beach	USA	Gas	1998	1,376	100
Thames	USA	Coal	1990	208	100
Warrior Run	USA	Coal	2000	205	100
Wind facilities operated under management or operations and maintenance agreements	USA	Wind	2005	377	0
Latin America					
Andres	Dom. Republic	Gas	2003	319	100
Gener Centrogener (7 plants)(2)	Chile	Hydro/Coal/Oil	2000	682	99
Gener Electrica de Santiago (2 plants)(3)	Chile	Gas/Diesel	2000	479	89
Gener Energía Verde (3 plants)(4)	Chile	Biomass/Diesel	2000	42	99
Gener Guacolda	Chile	Coal	2000	304	49
Gener Norgener	Chile	Coal/Pet Coke	2000	277	99
Gener TermoAndes	Argentina	Gas	2000	643	99
Itabo (5 plants)(5)	Dom. Republic	Coal/Oil	2000	586	25
Los Mina	Dom. Republic	Gas	2000	236	100
Tietê (10 plants)(6)(7)	Brazil	Hydro	1999	2,650	24
Uruguaiana(7)	Brazil	Gas	2000	639	46

Contract Generation continued
(As of December 31, 2005)

Generation Facilities	Geographic Location	Dominant Fuel	Year of Acquisition or Commencement of Commercial Operations	Gross MW	AES Equity Interest (Percent Rounded)
Europe/Middle East/Africa					
Barka	Oman	Gas	2003	456	35
Bohemia	Czech. Rep.	Coal/Biomass	2001	50	100
Borsod	Hungary	Biomass/Coal/Gas	1996	96	100
Ebute	Nigeria	Gas	2001	305	95
Elsta	Netherlands	Gas	1998	630	50
Kilroot	N. Ireland, U.K.	Coal/Oil	1992	520	97
Lal Pir	Pakistan	Oil	1997	362	55
Pak Gen	Pakistan	Oil	1998	365	55
Ras Laffan	Qatar	Gas	2004	756	55
Tisza II	Hungary	Oil/Gas	1996	900	100
Asia					
Aixi	China	Coal	1998	51	71
Chengdu	China	Gas	1997	50	35
Cili	China	Hydro	1994	26	51
Hefei	China	Oil	1997	115	70
Jiaozuo	China	Coal	1997	250	70
Kelanitissa	Sri Lanka	Diesel	2003	168	90
OPGC	India	Coal	1998	420	49
Wuhu	China	Coal	1996	250	25
Yangcheng	China	Coal	2001	2,100	25
			Total	23,369	

Under Construction

Generation Facilities	Geographic Location	Dominant Fuel	Commencement of Commercial Operations	Gross MW	AES Equity Interest (Percent Rounded)
North America					
Buffalo Gap	USA	Wind	2006	121	100
Latin America					
Los Vientos	Chile	Diesel	2006	120	99
Europe/Middle East/Africa					
Cartagena	Spain	Gas	2006	1,200	71

---

(1) As of March 2006, AES sold its direct interest in Kingston Cogeneration Limited Partnership, a 110 MW cogeneration power plant.

(2) Gener-Centrogener plants: Ventanas, Laguna Verde, Laguna Verde Turbogas, Alfalfal, Maitenas, Queltehues and Volcán.

(3) Gener-Eletrica de Santiago plants: Nueva Renca and Renca.

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

(5) Itabo plants: Itabo, Santo Domingo, Timbeque, Los Mina and Higuamo.

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

(7) As a result of the restructuring between some of our Brazilian holding companies and BNDES which was completed in January 2004, we have a 46% ownership interest in AES Uruguaiana and a 24% interest in AES Tietê. AES retains control of these entities through the holding company, Brasiliana Energia, S.A.

Competitive Supply
(As of December 31, 2005)

Generation Facilities	Geographic Location	Dominant Fuel	Year of Acquisition or Commencement of Commercial Operations	Gross MW	AES Equity Interest (Percent Rounded)
North America					
Cayuga	USA	Coal	1999	306	100
Deepwater	USA	Pet Coke	1986	160	100
Greenidge	USA	Coal	1999	161	100
Somerset	USA	Coal	1999	675	100
Westover	USA	Coal	1999	126	100
Latin America					
Alicura	Argentina	Hydro	2000	1,040	96
Central Dique	Argentina	Gas/Diesel	1998	68	51
Paraná-GT	Argentina	Gas	2001	845	100
Quebrada de Ullum(1)	Argentina	Hydro	2004	45	0
Rio Juramento Cabra Corral	Argentina	Hydro	1995	102	98
Rio Juramento El Tunal	Argentina	Hydro	1995	10	98
San Juan Sarmiento	Argentina	Gas	1996	33	98
San Juan Ullum	Argentina	Hydro	1996	45	98
San Nicolás	Argentina	Coal/Gas/Oil	1993	650	96
Bayano	Panama	Hydro	1999	260	49
Chiriqui Esti	Panama	Hydro	2003	120	49
Chiriqui La Estrella	Panama	Hydro	1999	42	49
Chiriqui Los Valles	Panama	Hydro	1999	48	49
Chivor	Colombia	Hydro	2000	1,000	99
Panama	Panama	Oil	1999	42	49
Europe/Middle East/Africa					
Indian Queens	England, U.K.	Oil	1996	140	100
Tiszapalkonya	Hungary	Biomass/Coal	1996	116	100
Asia					
Ekibastuz(2)	Kazakhstan	Coal	1996	4,000	100
Shulbinsk(3)	Kazakhstan	Hydro	1997	702	0
Sogrinsk CHP	Kazakhstan	Coal	1997	301	100
Ust-Kamenogorsk(3)	Kazakhstan	Hydro	1997	331	0
Ust-Kamenogorsk CHP	Kazakhstan	Coal	1997	1,354	100
Ust-Kamenogorsk Heat Nets(1)	Kazakhstan	Coal	1998	270	0
			Total	12,992	

(1) Although our equity interest in these businesses is zero, we operate these businesses through a management agreement.

(2) AES fully owns and operates Maikuben West coal mine in Kazakhstan, which supplies coal to this facility.

(3) Although our equity interest in these businesses is zero, we operate these businesses through a concession agreement.

Regulated Utilities
(As of December 31, 2005)

Generation Facilities	Geographic Location	Dominant Fuel	Year of Acquisition or Commencement of Commercial Operations	Gross MW	AES Equity Interest (Percent Rounded)
North America					
IPL (4 plants)(1)	USA	Coal/Gas/Oil	2001	3,370	100
Latin America					
EDC (5 plants)(2)	Venezuela	Oil/Gas	2000	2,616	86
Europe/Africa/Middle East					
SONEL (12 plants)(3)	Cameroon	Hydro/Diesel/ Heavy Fuel Oil	2001	1,014	56
				7,000	

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

(2) EDC plants: Amplicacion Tacoa, Tacoa, Arrecifes, Oscar Augusto Machado and Genevapca.

(3) SONEL plants: Edéa, Song Loulou, Limbé, Bassa, Bafoussam, Logbaba, Logbaba II, Oyomabang I Oyomabang II, Mefou, Lagdo and Djamboutou.

Under Construction

Generation Facilities	Geographic Location	Dominant Fuel	Commencement of Commercial Operations	Gross MW	AES Equity Interest (Percent, Rounded)
Latin America					
EDC (La Raisa plant)	Venezuela	Gas	2007	200	86

Distribution Facilities	Geographic Location	Approx. Number of Customers Served	Year of Acquisition or Commencement of Commercial Operations	Approx. Gigawatt Hours	AES Equity Interest (Percent, Rounded)
North America					
IPL	USA	460,000	2001	16,278	100
Latin America					
CAESS	El Salvador	487,000	2000	1,980	75
CLESA	El Salvador	272,000	1998	726	64
DEUSEM	El Salvador	53,000	2000	95	74
EDE Este(1)	Dom. Republic	331,000	2004	2,136	0
EDC	Venezuela	1,030,000	2000	10,523	86
Edelap	Argentina	296,000	1998	2,363	90
Eden	Argentina	300,000	1997	2,107	90
Edes	Argentina	154,000	1997	721	90
EEO	El Salvador	200,000	2000	408	89
Eletropaulo(2)	Brazil	5,298,000	1998	31,634	34
Sul(3)	Brazil	1,046,000	1997	6,922	100

Regulated Utilities continued
(As of December 31, 2005)

Distribution Facilities	Geographic Location	Approx. Number of Customers Served	Year of Acquisition or Commencement of Commercial Operations	Approx. Gigawatt Hours	AES Equity Interest (Percent, Rounded)
Europe/Middle East/Africa					
Kievoblenergo	Ukraine	800,000	2001	3,332	89
Rivneenergo	Ukraine	388,000	2001	1,895	80
SONEL	Cameroon	528,000	2001	3,258	56
Asia					
Eastern Kazakhstan REC(1)	Kazakhstan	282,000	1999	1,998	0
Semipalatinsk REC(1)	Kazakhstan	180,000	1999	834	0
			Total	87,210	

(1) Although our equity interest in these businesses is zero, we operate these businesses through a management agreement. AES previously had a controlling interest in EDE Este from 1999 to 2004.

(2) As a result of the restructuring between some of our Brazilian holding companies and BNDES which was completed in January 2004, our ownership interest in Eletropaulo is 34%. AES retains control through the holding company, Brasiliana Energia, S.A.

(3) As a result of the restructuring of certain of our Brazilian holding companies and BNDES that was completed in January 2004, AES Sul may be contributed at the option of BNDES to Brasiliana Energia, S.A. after AES Sul has completed its own debt restructuring.

Growth Opportunities

We continuously consider options to expand our business. In addition to expanding our two primary lines of business, power generation and distribution, we believe we can leverage the skills and experience necessary to be successful in our primary businesses into other businesses that have similar characteristics. We believe these transferable skills include our knowledge and skill in dealing with complex deal structuring and project financing for large capital intensive projects and dynamic local political and regulatory environments. We believe we have an additional advantage in situations where we can leverage our existing businesses. Our existing presence in certain countries can provide the relationships and insight into local rules, regulations, politics and business practices needed to be successful in both power and related non-power sectors. In addition, we seek to expand our businesses into other forms of energy production and delivery. This includes alternative energy businesses such as wind generation, the supply of liquefied natural gas (LNG) to certain targeted North American markets, the production of greenhouse gas reduction activities, and new energy technology. For example, we have already begun to implement this strategy in Kazakhstan, where we own and operate a coal mine, the Middle East, where we own and operate water desalination plants, and the Dominican Republic, where we own and operate an LNG regasification terminal, each ancillary to our existing power businesses.

The Company continues to maintain an active development pipeline of potential growth investments. It continues to devote significant resources at both the corporate and business level in support of business development opportunities, which may include expansion at existing locations, new greenfield investments, privatization of government assets, and mergers and acquisitions. It is this funding of development costs in support of new projects and privatization opportunities which could lead to significant new investments in 2006.

Customers

We sell to a wide variety of customers. No individual customer accounted for 10% or more of our 2005 total revenues.

Employees

As of December 31, 2005, we employed approximately 30,000 people.

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 web 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 at *http://www.aes.com*. After the reports are filed with the Securities and Exchange Commission, they are available from the Company free of charge. Material contained on our website is not part of and is not incorporated by reference in this annual report on Form 10-K.

AES s Code of Business Conduct and Ethics (Code of Conduct) and Corporate Governance Guidelines have been adopted by the 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 AES subsidiaries and affiliates. The Code of Conduct and the Corporate Governance Guidelines are located in their entirety on the Company s web site (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.

Executive Officers of the Registrant

The following individuals listed below are AES s executive officers:

Paul Hanrahan, 48 years old, is the President and Chief Executive Officer of the Company. Prior to assuming his current position, Mr. Hanrahan was the Chief Operating Officer and Executive Vice President of the Company. In this role, he was responsible for 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. 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.

David S. Gee, 51 years old, is an Executive Vice President and the Regional President of North America. Prior to joining the Company in 2004, Mr. Gee was Vice President of Strategic Planning for PG&E in San Francisco, California. Mr. Gee was a principal consultant for McKinsey & Co. from 1985 to 2000 in Houston, Mexico City and London. He was also an Associate for Baker Hughes and Booz Allen & Hamilton in Houston, Texas. Mr. Gee has a Bachelor of Science degree in Chemical Engineering from the University of Virginia and a Master of Science degree in Finance from the Sloan School of Management at the Massachusetts Institute of Technology.

Andres R. Gluski, 48 years old, is an Executive Vice President and the Regional President of Latin America. Mr. Gluski was Senior Vice President for the Caribbean and Central America from 2003 to 2005, was Group Manager and CEO of Electricidad de Caracas (EDC) (Venezuela) from 2002 to 2003, served as CEO of Gener (Chile) in 2001 and was Executive Vice President of EDC and Corporacion EDC. Prior to joining the Company in 1997, Mr. Gluski was Executive Vice President of Corporate Banking for Banco de Venezuela and Executive Vice President of Finance of CANTV in Venezuela. Mr. Gluski is a graduate of Wake Forest University and holds a Master of Arts and a Doctorate in Economics from the University of Virginia.

Victoria D. Harker, 41 years old, is an Executive Vice President and the Chief Financial Officer of the Company. Ms. Harker joined the Company as Chief Financial Officer on January 23, 2006. Prior to joining the Company, Ms. Harker held the positions of Acting Chief Financial Officer, Senior Vice President and Treasurer of MCI from November 2002 through January 2006. Prior to that, Ms. Harker served as Chief Financial Officer 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. Ms. Harker received her Bachelor of Arts degree in English and Economics from the University of Virginia and a Master s in Business Administration, Finance from American University.

Robert F. Hemphill, Jr., 62 years old, is an Executive Vice President and has been Executive Vice President since rejoining the Company on February 5, 2004. Mr. Hemphill served as a Director of the Company from June 1996 to February 2004 and was an Executive Vice President from 1982 to June 1996. Prior to this, Mr. Hemphill held various leadership positions since joining the Company in 1982. Mr. Hemphill also serves on the Boards of Reactive Nanotechnologies, Inc. and Trophogen Inc. Mr. Hemphill received a Bachelor of Arts degree in Political Science from Yale University, a Master of Arts in Political Science from the University of California, Los Angeles, and a Master s in Business Administration, Finance from George Washington University.

Haresh R. Jaisinghani, 39 years old, is an Executive Vice President and the Regional President of Asia and Middle East. Prior to assuming his current position, Mr. Jaisinghani was Vice President of Generation Asia from 2003 to 2005 and was Group Manager of Asia from 2001 to 2003. Mr. Jaisinghani also served as Managing Director and Country Head of Bangladesh from 1997 through 1999. Prior to joining the Company in 1994, Mr. Jaisinghani was Project Director for GM Bijlani Construction Company. Mr. Jaisinghani holds a Bachelor in Civil Engineering from the University of Bombay, India and a Master of Science in Construction Management from the University of Maryland.

Jay L. Kloosterboer, 45 years old, is the Executive Vice President of Business Excellence. Mr. Kloosterboer joined the Company in 2003 as Vice President and Chief Human Resource Officer. Prior to joining the Company, he was Vice President, Human Resources and Communications for Honeywell International s Automation and Control Solutions business. Mr. Kloosterboer also held management positions at General Electric and Morgan Stanley. He received his Bachelor of Arts degree from Marquette University and holds a Master of Arts degree from the New Mexico State University.

William R. Luraschi, 42 years old, is the Executive Vice President, Business Development and Strategy. Mr. Luraschi joined AES in 1993 and has been an Executive Vice President since July 2003. He was General Counsel of the Company from January 1994 until May 2005. Mr. Luraschi also served as Corporate Secretary from February 1996 until June 2002. Prior to joining the Company, he was an attorney with the law firm of Chadbourne & Parke, LLP. Mr. Luraschi received a Bachelor of Science from the University of Connecticut and holds a Juris Doctorate from Rutgers School of Law.

Brian A. Miller, 40 years old, is an Executive Vice President, General Counsel and Corporate Secretary of the Company. Mr. Miller joined the Company in 2001 and has served as Vice President, Deputy General Counsel, Corporate Secretary, General Counsel for North America and Assistant General Counsel. Prior to joining the Company, he was an attorney with the law firm Chadbourne & Parke, LLP. Mr. Miller received his bachelor s degree in History and Economics from Boston College and holds a Juris Doctorate from the University of Connecticut School of Law.

Shahzad Qasim, 51 years old, is an Executive Vice President and the Regional President of Europe and Africa. Mr. Qasim served as Senior Vice President of Generation Middle East from 2001 to 2005, Vice President of the Middle East and South Asia from 1998 to 2000, Project Director of Pakistan and Central Asia from 1993 to 1998 and Director of New Ventures from 1992 to 1993. Prior to joining the Company, he was an engagement manager for McKinsey & Co. Mr. Qasim has a Bachelor of Science in Mechanical Engineering from NED Engineering University, Pakistan and a Masters in Energy Management and Policy from the University of Pennsylvania.

Regulatory Matters

United States. Over the past decade, a series of regulatory policies have been adopted in the United States that encourage competition in wholesale and retail electricity markets. These policies have been implemented both at the federal level and, in many states, at the state level. The federal government regulates wholesale power markets and transmission facilities in most of the continental U.S., while each of the fifty states regulates retail electricity markets and distribution.

The Federal Energy Regulatory Commission (FERC) has ratemaking jurisdiction and other authority with respect to interstate wholesale sales and transmission of electric energy under the Federal Power Act (FPA) and with respect to certain interstate sales, transportation and storage of natural gas under the Natural Gas Act. In 1996, the FERC issued Order # 888, which mandated the functional separation of generation and transmission operations and required utilities to provide open access to their transmission systems. Each utility under the FERC s jurisdiction was required to file an Open Access Transmission Tariff. In 2000, the FERC issued Order # 2000, which established the functions and characteristics of Regional Transmission Organizations (RTOs) as a means to ensure independent administration of the open access policy and to help increase investment in transmission infrastructure. The RTO assumed functions traditionally handled by utilities, such as security, coordination and planning.

Beginning in the fall of 2001, regulatory officials in the United States began to re-examine the nature and pace of deregulation of electricity markets. This re-examination was primarily a result of extreme price volatility and energy shortages in California and portions of the western markets during the period from May 2000 through June 2001. The conclusions reached in this re-examination have not been uniform, but rather have differed from state to state and between the federal government and the states themselves. Thus, a number of states have advocated against restructuring and abandoned any efforts to proceed with deregulation of retail markets, while the FERC has continued its efforts to enhance open access electric transmission and enhance competition in bulk power (wholesale) markets, albeit at a somewhat slower pace. This has led to a number of confrontations and legal proceedings between the FERC and the states over jurisdiction. We believe that over the next decade the United States will continue to resemble a patchwork quilt of differing regulatory policies at the retail level.

The federal government, through regulations promulgated by the FERC, has primary jurisdiction over wholesale electricity markets and transmission services. Since 1986, the FERC has approved market based rate authority for many providers of wholesale generation, and the mix of market players has shifted toward non-utility entities, referred to as Independent Power Producers (IPPs) or Electric Wholesale Generators (EWGs), whose rates are negotiated rather than based on costs. The FERC has issued a number of orders that increase the reporting requirements of entities requesting market based rates. The FERC is in the process of issuing a rulemaking concerning the four criteria examined in granting market based rate authority and the resulting regulations may result in a more stringent analysis and therefore the denial of market based rate authority to a number of entities. Recently there has also been a shift back to utilities supplying their own generation, through affiliate contracts, acquisition of distressed assets, and traditional utility construction. These assets are included in ratebase and represent a move back to traditional cost of service ratemaking regulation.

On August 8, 2005 the President signed into law the Energy Policy Act of 2005 (EPAct 2005). The legislation repealed the Public Utility Holding Company Act (PUHCA of 1935) and replaced it with the Public Utility Holding Company Act of 2005 (PUHCA of 2005), which became effective on February 8, 2006. The repeal of the PUHCA of 1935 removed utility holding companies from the jurisdiction of the SEC and greatly reduced the financial and governance restrictions imposed on utility holding companies. The PUHCA of 2005 increases federal and state access to books and records, but does not restrict mergers and acquisitions of non-contiguous utilities as did the previous law.

Under Section 203 of the FPA, as amended by EPAct 2005, the FERC has increased authority to review mergers and acquisitions, including acquisitions of foreign utility companies. However, the FERC has issued regulations that give a holding company that owns a transmitting utility or an electric utility company and has captive U.S. customers (such as AES) blanket authority to acquire a foreign utility company upon making a notice filing containing specific certifications with respect to the protection of such customers from the effects of the acquisition.

EPAct 2005 also provides the FERC with new authority to certify an Electric Reliability Organization (ERO) that will set mandatory reliability standards for the U.S. grid. The North American Electric Reliability Council (NERC) will most likely fill this role and have enforcement authority. NERC recently adopted a set of reliability standards that consist of existing operating and planning standards. Although NERC has not historically had authority to mandate compliance with these standards, utilities generally choose to voluntarily comply with the standards. The new legislation gives NERC the ability to make standards mandatory and would grant them the authority to enforce these standards through the issuance of financial penalties.

Finally, EPAct 2005 amends the Public Utility Regulatory Policies Act of 1978 (PURPA) and instructs the FERC to promulgate regulations to implement the amendments. Pursuant to this directive, the FERC has issued a final rule that: (i) prescribes new restrictive criteria that new cogeneration facilities must meet in order to be designated as qualifying facilities (QFs) under PURPA; (ii) removes the restrictions on ownership of QFs by an entity that is primarily engaged in the generation or sale of electric power; and (iii) for new QFs eliminates certain regulatory exemptions that QFs previously received. The FERC has also issued a proposed rule that for new power sales contracts would effectively remove the requirement that utilities purchase energy and capacity produced by QFs if the utilities (i) are located within the control areas of the Midwest Independent Transmission System Operator, Inc. (Midwest ISO), PJM Interconnection, L.L.C., ISO New England, Inc. or the New York Independent System Operators or (ii) otherwise meet certain criteria relating to market access for QFs. We are evaluating the impact of these rules on our businesses.

There are currently major changes pending in the structure and rules governing the California wholesale energy market. The outcome of any significant market or regulatory changes will affect market conditions for all market participants, including AES. As a result of price volatility during 2000 and 2001, a number of parties, including the State of California and the California Independent System Operator, are seeking refunds from certain entities that supplied power within the state during 2000 and 2001, although our overall exposure to this risk is largely mitigated as a result of our tolling agreement related to the Southland plants. However, a recent Ninth Circuit Court of Appeals Opinion found that the FERC had abused its administrative discretion by declining to order refunds for violations of its reporting requirements and remanded the issue to the FERC. Appeal of that order is currently pending. Separate appeals in the Ninth Circuit Court of Appeals are also pending which could change the timing of the refund period. AES Placerita made sales to the California Power Exchange during this period. Depending on the result of the pending appeals and the time period at issue, as well as the method of calculating refunds, AES Placerita s exposure could be $23 million. There are no performance bonds or corporate guarantees supporting AES Placerita and no liability has been established in the refund proceedings for other AES entities. In addition, we have been named in a number of lawsuits covering this period and are not certain of their outcome. See Item 3 Legal Proceedings in this Form 10-K.

In addition to the FERC regulation described above, IPL is subject to regulation by the Indiana Utility Regulatory Commission (IURC) as to 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 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. Such proceedings, which have occurred at irregular intervals, involve IPL, the staff of the IURC, the Indiana Office of Utility Consumer Counselor, and other interested consumer groups and customers. 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.

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 consumed from estimated fuel costs embedded in basic rates, subject to certain restrictions on the level of operating income. 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 the nitrogen oxide (NOx) compliance construction program and its multipollutant plan.

On April 1, 2005, IPL began participation in the restructured wholesale energy market operated by the Midwest ISO. The implementation of this restructured market marks a significant change in the way IPL buys and sells electricity and schedules generation. Prior to the restructured market, IPL dispatched its generation and purchased power resources directly to meet its demands. In the restructured market, IPL offers its generation and bids its demand into the market on an hourly basis. The Midwest ISO settles these hourly offers and bids based on locational marginal prices or LMPs, 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 Midwest ISO region. The Midwest ISO evaluates the market participants energy injections into, and withdrawals from, the system to economically dispatch the entire Midwest ISO system on a five-minute basis. Market participants are able to hedge their exposure to congestion charges, which result from constraints on the transmission system, with certain Financial Transmission Rights, or FTRs . Participants are allocated FTRs each year and are permitted to purchase additional FTRs. As anticipated and in keeping with similar market start-ups around the world, LMPs are volatile and there are process, data, and model issues requiring editing and enhancement. IPL and other market participants have raised concerns with certain Midwest ISO transactions and the resolution of these items could impact our results of operations.

Argentina. In January and February 2002, the Argentine government adopted many new economic measures as a result of the continuing political, social and economic crisis. These economic measures included (i) the abandonment of the country s fixed dollar-to-peso exchange rate, (ii) the conversion of U.S. dollar-denominated loans into pesos and (iii) the placement of restrictions on the convertibility of the Argentine peso. Since 2003, the political and social situation in Argentina has showed signs of stabilization, the Argentine peso has appreciated against the U.S. dollar, and the economy and electricity demand has started to recover.

The regulations adopted in 2002 and 2003 in the energy sector effectively overturned the U.S. dollar based nature of the electricity sector. In the wholesale power market, electricity generators declared their costs of generation (which reflected their fuel costs) on a semi-annual basis. Under the current regulations, energy prices were partially converted from the original U.S. dollar denomination into Argentine pesos (pesofied), following the pesofication of the price of natural gas. However, the authorities permitted the production cost for alternative fuels (fuel oil, coal) to reflect international costs. In order to avoid price increases associated with the use of alternative fuels, market regulations were changed so that the spot price will be set considering only production costs declared with natural gas. Therefore, while generators received remuneration for the use of alternative fuel, this cost is not considered when setting the spot price. Because of this, generation prices still reflect an artificially low fuel price, but because of the gas supply crisis and the subsequent agreement between the government and the gas producers to readapt the prices, as described below, this effect has been almost offset and gas prices will reach the original value in 2006.

During 2004, the Energy Secretariat reached agreements with natural gas and electricity producers to reform the energy markets. The agreement with natural gas producers established a recovery path that increased wellhead prices to 80% of the U.S. dollar price by July, 2005 and a second path that will reach export parity by the end of 2006. In the electricity sector, the Energy Secretariat passed Resolution 826/2004, inviting generators to partially contribute their existing and future credits in the Wholesale Electricity Market (WEM) from January 2004 to December 2006, which will fund new capacity to be installed by 2008. In exchange, the Government committed to reform the market rules to match the pre-crisis rules, setting the capacity payment with a U.S. dollar reference and eliminating all regulations fixing an artificially low price in the wholesale market by 2008. The Argentina government reached an agreement on this with more than 90% of the generators by May 2005. On October 7, 2005, the Energy Secretariat passed Resolution 1193/05 that starts the process of re-adaptation through the definitive agreement for the electricity market. This definitive agreement was signed on October 17, 2005. There can be no assurance, however, that the Argentina government will honor its commitment to release restrictive measures that it has placed upon wholesale prices after the new capacity is installed.

Under the previous regulations, 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. The tariffs of all distribution companies were converted to pesos and were frozen at the peso notional rate as of December 31, 2001. In October 2003, the Argentine Congress enacted Law No. 25,790 that established the procedure for renegotiation of the public utilities concessions and extended the period for that process until December 31, 2006. In combination, these circumstances create significant uncertainty surrounding the performance of the electricity industry in Argentina, including the Argentine subsidiaries of AES.

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 reached on July 14, 2005. As a first step during this process, a Distribution Value Added (DVA) increase of 28% effective February 1, 2005 has been granted. Invoicing of the tariff increase commenced in August 2005. The agreement also includes: (i) local cost adjustments to the tariff; (ii) elimination of penalties arising from the gas curtailment by Argentina; (iii) long term payment terms of penalties owed to the customers; (iv) and other favorable conditions which are intended to increase the company value. The agreement was the first of its kind signed with UNIREN (Unit for the Renegotiation and Analysis of Public Services Contracts) in the Argentine electricity sector. Upon execution of the Letter of Understanding, AES agreed to postpone or suspend certain international claims, however, the Letter of Understanding provides that if the government does not fulfill its commitments, AES may re-start the international claim process. AES has postponed any action until the tariff reset is finalized (not later than December 2006).

On October 24, 2005, EDEN and EDES, two AES distribution businesses in Argentina, 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 approved by a Governor Decree on November 30, 2005. This Letter of Understanding includes the following: (i) an initial 19% DVA increase effective August 2005, and an additional DVA increase which will be in force in accordance with National Government policies; (ii) penalties recorded during the 2002-2005 period will not be paid; (iii) Quality Service Regime penalties will be reduced and (iv) full tariff reset proceedings will be carried out in 2007. This Letter of Understanding also includes other favorable conditions beneficial to these distribution facilities. The Letter of Understanding provides that in case the government does not fulfill its commitments, AES may re-start the international claim process. AES has postponed any action with respect to international claims until the tariff reset is finalized (not later than December 2007).

Brazil. Under the present regulatory structure, the power industry in Brazil is regulated by the Brazilian government, acting through the Ministry of Mines and Energy (MME) and the National Electric Energy Agency (ANEEL), an independent federal regulatory agency which has exclusive authority over the Brazilian power industry.

ANEEL s main function is to ensure the efficient and economic supply of energy to consumers by monitoring prices and ensuring adherence to market rules by market participants in line with policies dictated by the MME. ANEEL supervises concessions for electricity generation, transmission, trading and distribution, including the approval of applications for the setting of tariff rates, and supervising and auditing the concessionaires. ANEEL s core areas of responsibility that are directly related to AES s businesses are: economic regulation, technical regulation and consumer affairs oversight.

On December 21, 2001, in order to compensate electricity distributors and generators for losses incurred during the rationing program instituted in June of that year, the President of Brazil issued a provisional measure. The provisional measure provided general authorization for: (i) the pass-through to consumers of costs incurred by generators for the purchase of energy at spot prices during the rationing program, (ii) the recovery in future years of revenue losses sustained by distributors during the rationing period, through an Extraordinary Tariff Adjustment (RTE), and (iii) the institution, by the Brazilian National Bank for Economic and Social Development (BNDES), of an emergency support program in order to compensate distributors, generators and independent power producers for the rationing impacts, which contemplates the disbursement of some loans to these companies.

The Brazilian government established a tracking account mechanism (CVA) to mitigate risks relating to Parcel A costs (non-manageable costs relating to energy purchase and sector charges that each distribution company is permitted to pass through to customers) not being passed-through to tariffs.

Generator s and distributor s losses are recovered through the RTE, as calculated pursuant to a resolution issued by ANEEL on January 24, 2002 and a resolution issued by the Energy Crisis Coordination Committee, the committee created as result of the energy crisis, on December 21, 2001. As of January 2002, the Company was permitted to charge consumers the RTE over a 65-month period. However, after regulatory review, and in order to allow the full recovery of the Parcel A costs, ANEEL, through a resolution issued on January 12, 2004, established the extension of AES Eletropaulo s RTE recovery period (from 65 to 70 months), and that Parcel A recovery will happen only after the RTE recovery.

Under the rationing agreement of 2001, AES Sul was permitted to record additional revenue and a corresponding receivable from the spot market during 2001 and the first quarter of 2002. However, ANEEL promulgated Order # 288 in May 2002, which retroactively changed the calculation methods for electricity pricing in the Brazilian Wholesale Energy Market, Mercado Atacadista de Energia or MAE , transforming a $187 million credit in the favor of AES Sul into a debt of $34.8 million. We recorded a pretax provision of approximately $160 million, including the amounts for AES Sul, against revenues during May 2002, to reflect the negative impacts of this retroactive regulatory decision.

On August 23, 2002, AES Sul filed a lawsuit against the ANEEL seeking the annulment of Order # 288. On September 18, 2002, a preliminary injunction was granted to AES Sul. This injunction was suspended due to an Interlocutory Appeal filed by ANEEL on September 20, 2002. However, on July 20, 2005, ANEEL s appeal was deemed groundless by the Federal Region Court, and the original injunction granted AES Sul was reinstated. Therefore, ANEEL must file with the Câmara de Comercialização de Energia Elétrica (CCEE) (formerly the MAE) to recalculate settlement amounts for each market participant during this disputed period, and to issue new credit/debit invoices to these market participants. A decision on the merits is still pending with the first level court.

If a settlement occurs with the effect of Order # 288 in place, AES Sul will owe approximately a net amount of $30 million, based upon the December 31, 2004 exchange rate. AES Sul does not believe it will have sufficient funds to make this payment and several creditors have filed lawsuits in an effort to collect amounts they claim are overdue. AES Sul is petitioning the courts to aggregate the individual lawsuits with payments until the matter is resolved. If AES Sul prevails and the MAE settlement occurs absent the effect of Order # 288, AES Sul will receive approximately $132 million, based upon the December 31, 2004 exchange rate. If AES Sul is unsuccessful and unable to pay any amount that may be due to MAE, penalties and fines could be imposed up to and including the termination of the concession contract by ANEEL. AES Sul is current on all MAE charges and costs incurred subsequent to the period in question in the Order # 288 matter. All amounts, including the amount owed to MAE in the event AES Sul loses the case, are provisioned in AES Sul s books.

The CVA is a tracking account that records non-manageable costs monthly price variations (positive and negative) over the course of the year. At each tariff adjustment date, distribution companies would be allowed an additional tariff increase, for the following 12 months, in order to compensate for the accumulated value of the CVA plus interest. On April 4, 2003, the MME issued a decree postponing, for a 1-year period, the tracking account tariff increase. According to this decree, the pass-through to tariffs of the amounts accumulated in the tracking account for the distribution concessionaires that had been scheduled to occur from April 8, 2003 to April 7, 2004 were postponed to the subsequent year s tariff adjustment. As a result, approximately $12 million and $173 million, for AES Sul and AES Eletropaulo, respectively, are to be recovered over a 24-month period rather than the usual 12-month period. AES Eletropaulo and AES Sul received in their respective 2004 tariff adjustments, 50% of the deferred CVA recoverable over a 12-month period; and the additional 50% as part of the 2005 tariff adjustments, which will be recoverable over the ensuing 12-month period.

In order to compensate for the deferral of the increase relating to the tracking account, BNDES provided distribution companies with loans, which will be repaid during the recovery period. On December 23, 2004, AES Sul received a BNDES loan equivalent to $16.5 million and on June 3, 2004, AES Eletropaulo received a BNDES loan equivalent to $166 million, both to be repaid within the recovery period.

In order to maintain the economic and financial equilibrium of the concession, utilities are entitled to the following types of tariff adjustments contemplated in the concession contracts:

- annual tariff adjustments;
- tariff reset; and
- extraordinary revisions, in the event of significant changes in concessionaires cost structure.

The primary purpose of the Annual Tariff Adjustment (IRT) is the maintenance of an adjusted tariff for inflation and the sharing of efficiency gains with consumers. The IRT uses a formula such that non-manageable (Parcel A) costs are passed through to the consumers and manageable (Parcel B) costs are indexed to inflation. An X-Factor is applied to capture the sharing of efficiency gains, effectively reducing the inflation index that is applied to Parcel B costs. The operations and maintenance costs

22

considered in the tariff are based on the concept of a Reference Company, not actual costs. In many cases, the Reference Company may not be reflective of distribution companies operating in Brazil and thus, underestimate true operating costs. These costs which include certain taxes and other issues are being discussed under administrative appeal with ANEEL. In addition, the distribution companies are challenging certain methodologies used for the tariff revision.

ANEEL authorized an average adjustment of 2.12% for AES Eletropaulo tariffs on July 4, 2005. ANEEL authorized an average adjustment of 9.42% for AES Sul on April 19, 2005.

The Brazilian government carried out a wide reform in the Brazilian power sector and on December 11, 2003, announced a proposed new model for the Brazilian power sector (the New Power Sector Model) and enacted Provisional Measures #144 and #145, which set forth the basic rules that will govern the New Power Sector Model. On March 15, 2004, Law #10848 was enacted, which sets forth the basis of the new regulatory framework and general rules for power commercialization, regulated by Decree #5163, of July 30, 2004, and other administrative rulings.

The main points of the New Power Sector Model and its impact on AES businesses in Brazil are as follows:

- It creates two energy commercialization environments: (1) the regulated contractual environment (ACR), intended for the distribution companies, and (2) the free contract environment (ACL), designed for traders and free consumers.

- As of January 2005, every distribution utility is obligated to meet 100% of its anticipated energy requirements, subject to the application of penalties. Compliance with such obligation requires distribution companies to contract for energy through: (i) auctions of energy from new (proposed) generation projects; (ii) auctions of energy from existing generation facilities; and (iii) other sources, including public calls to purchase energy from distributed generation; renewable energy sources (through PROINFA Brazilian Renewable Energy Incentive Program); pre-existing purchases made before Law #10848/04; and purchases from Itaipu.

- Distribution utilities can pass through the amounts contracted, up to 103% of their load, conditioned upon the amendment of the concession contracts: ANEEL will adopt a new pass-through methodology in the annual tariff adjustment; and variations of the energy purchase costs will be reflected in the tracking account (CVA).

As part of the implementation process of the New Power Sector Model, distribution companies signed amendments to the concession contracts, which modified the clause relating to the tariffs with respect to: (i) methodology of power purchase cost pass-through; and (ii) exclusion of PIS/COFINS (taxes over revenue).

The Electric Energy Commercialization Chamber (CCEE), successor of the MAE, carried out, on December 7, 2004, the largest auction in the country s history, in which power distribution utilities bought energy to serve 100% of their markets projected for 2005, 2006 and 2007. The energy traded in this auction will be the object of contracts lasting eight years starting from 2005, 2006 and 2007. The Brazilian government is inserting the rights for the CVA of energy purchased from the auction to agreement on additional amendments to concession contracts. This can represent risk relating to certain aspects of the current IRT methodology. The New Power Sector Model Law is currently being challenged on constitutional grounds before the Brazilian Supreme Court. To date, the Brazilian Supreme Court has not reached a final decision and we do not know when such a decision may be reached. Therefore, the New Power Sector Model is currently in force. Regardless of the Supreme Court s final decision, certain portions of the New Power Sector Model relating to restrictions on distributors performing activities unrelated to the distribution of electricity, including sales of energy by distributors to free consumers and the elimination of contracts between related parties, are expected to remain in full force and effect.

If all or a portion of the New Power Sector Model is determined unconstitutional by the Brazilian Supreme Court, the regulatory scheme introduced by the New Power Sector Model may not come into effect, generating uncertainty as to how and when the Brazilian government will be able to introduce changes to the electric energy sector. We have already purchased a significant portion of our electricity needs through 2016, and the pass-through to tariffs of such electricity is expected to continue to be governed by the regulation in effect on the date of the purchase. As such, irrespective of the outcome of the Supreme Court s decision, we believe that in the short term the effects of any such decision on our activities will be limited. Nevertheless, the exact effect of an unfavorable outcome of the legal proceedings on us is difficult to predict and it could have an adverse impact on our business and results of operations.

Cameroon. The law governing the electricity sector was passed and promulgated in December 1998, which defines the new institutional organization of the electricity sector. This law, and subsequent ministerial decrees and orders, govern the activities of the electricity sector, sets the rates and basis for the calculation, recovery and distribution of royalties due by operators in the electricity sector, and spells out required documents and charges for the processing of applications relating to concession, license, authorization and declaration in order to carry out generation, transmission, distribution, importation, exportation and sales of electricity.

The mission of the Electricity Sector Regulatory Board (ARSEL) involves regulating and ensuring the proper functioning of the electricity sector, maintaining its economic and financial balance 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 18, 2001, between the Republic of Cameroon and AES SONEL covers a twenty-year (20) period of which the first three years constituted a grace period to permit resolution of issues existing at the time of the privatization, and all penalties were waived. In 2004, AES SONEL and the Cameroonian Government started renegotiating the concession contract. The issues included in this renegotiation process were: the quality of services requirements, the connection targets, the tariff formulation, the obligation of developing new generation capacity and the penalties regime. AES SONEL expects to complete the renegotiation process in 2006.

Chile. In Chile, the regulation of production schedules for electricity generation facilities is based on the marginal cost of production, which is the cost of the most expensive unit required by the system at the time. The spot price among generation companies for both electrical capacity (the amount of electricity available at any point in time) and electrical energy (the amount of electricity produced or consumed over a period of time) is also the marginal cost of production. Chile has four electricity systems. The major two interconnected electricity systems are the Central Interconnected System (*Sistema Interconectado Central*) (SIC) and the Northern Interconnected System (*Sistema Interconectado del Norte Grande*) (SING), which cover almost 97% of the population of the country.

In order to meet demand for electricity at any point in time, the lowest marginal cost generating plant in an interconnected system is used before the next lowest marginal cost plant is dispatched. As a result, at any specific level of demand, the appropriate supply will be provided at the lowest possible marginal cost of production available in the system.

Generation companies are free to enter into sales contracts with distribution companies and other customers for the sale of capacity and energy. However, the electricity necessary to fulfill these contracts is provided by the contracting generation company only if the generation company s marginal cost of production is low enough for its generating capacity to be dispatched to meet demand. Otherwise, the generation company will purchase electricity from other generation companies at the marginal cost of production in the system.

According to existing law, during periods when production cannot meet system demands, regardless of whether the government has enacted a rationing decree, the price of energy exchanges among generation companies is valued at the shortage cost determined by the National Energy Commission (NEC), which takes into account the cost to consumers for not having energy available. This law was first tested in November 1998 when generators in the SIC were unable to agree on the implementation of the shortage cost during the supply deficit and associated mandated rationing periods. The matter was referred to the Ministry of Economy, which issued its ruling in March 1999. Based on this decision, generators with energy deficits at the time were required to pay companies with energy surpluses the shortage cost or corresponding spot price equal to the cost of unserved energy for energy purchases during that period.

The prices paid to generation companies by distribution companies for capacity and energy to be resold to their retail customers are, pursuant to law, based on the expected average marginal cost of capacity or energy. In order to ensure price stability, however, the regulatory authorities in Chile establish prices, known as node prices, every six months to be paid by distribution companies for the energy and capacity requirements of regulated consumers. Node prices for energy are calculated on the basis of the projections of the expected marginal costs within the system over the next 24 to 48 months, in the case of the SIC and the SING. The formula takes into account, among other things, assumptions regarding available supply and demand in the future. Node prices for capacity are based on the marginal investment required to meet peak demand, based on the cost of a diesel-fired turbine. Prices for capacity and energy sold to large customers (over 0.5 MW) and other generation companies purchasing on a contractual basis are unregulated and are often set with reference to node prices, alternative fuel prices, exchange rates and other factors. If average prices for capacity and energy sold to non-regulated customers differ from node prices by more than a defined percentage (5%-30%, calculated pursuant to regulations), node prices are adjusted upward or downward, as the case may be, so that the difference between such prices equals such percentage. In contrast, the spot price paid by one generation company to another for energy is referred to as the system marginal cost, which is based on the actual marginal cost of the highest cost generator producing electricity in the system during the relevant period, as determined on an hourly basis.

Since the system marginal cost for energy is set weekly (but may in certain circumstances be changed on a daily basis) based on variables that can change on an instantaneous basis, and the node price for energy is set every six months based on projections of these variables over the next 24 to 48 months, in the case of the SIC and SING, the system marginal cost for energy of a system tends to be more volatile than the node price for energy of that system. In periods of low water conditions that require greater generation of energy by more costly thermoelectric plants, the system marginal cost typically exceeds the node price. In periods of high water conditions when lower cost hydroelectric facilities can meet the majority of demand, the system marginal cost is typically below the node price and may in fact decline to zero at some hours.

On March 13, 2004, Law No. 19.940 was enacted establishing amendments to the existing Electricity Law, principally in relation to tolls charged for the use of high voltage network and transmission systems. The reduction of the minimum demand required to be considered as an unregulated customer went from 2 MW to 0.5 MW. In addition, other factors considered are the reduction of the floating band for regulated price from 10% to 5%, the incorporation of elements to create an ancillary services market and the pricing mechanism for small and medium-sized electricity systems. The modifications contained in Law No. 19.940 maintain or improve our position with regard to both our current status and projected development and, in particular, with regard to the issues related with transmission tolls. In addition, the Regulations to the Electricity Law, Supreme Decree No. 327, which was modified on October 9, 2003 with respect to the clarification of the methodology utilized to calculate transmission tolls, has been replaced by Law No. 19.940.

On March 25, 2004, the Argentine government published Resolution 265, which privileged the domestic supply of natural gas, immediately affecting the export of natural gas to neighboring countries, primarily Chile. However, this resolution provided suppliers with alternative means of supply under existing export contracts. Between April and June 2004, daily export restrictions to Chile fluctuated between 20% and 47% of contracted volumes, depending on domestic demand. At the end of 2004, the curtailments were less than 10% due to improved hydrological conditions in Argentina and Chile, and increased availability of Bolivian gas.

This situation changed at the beginning of 2005 when as a result of high electricity demand and natural gas consumption in Argentina, in addition to the policy established by CAMMESA to conserve water under Resolution 839, the curtailments increased during summer months reaching a peak of almost 50%, equivalent to 402 Mmcf/d at the end of May 2005. From May until September 2005, the daily export restrictions to Chile fluctuated between 40% and 10%. In the last quarter of 2005, the restrictions were reduced 7% to 12%, mainly due to improved hydrological conditions compared to the beginning of the year.

Our subsidiary Electrica Santiago produces electricity by burning natural gas produced in southern Argentina which is transported to central Argentina through a pipeline owned by Transportadora Gas del Norte S.A., or TGN, and then to Chile. The TGN pipeline supplies consumers in Argentina and Chile. Interruptions in the supply and/or transportation of natural gas by TGN would adversely affect the operations and financial condition of Electrica Santiago. Such potential interruptions would materially impair Electrica Santiago s ability to generate electricity and would force it to rely on the spot market to purchase electricity to meet its contractual commitments. Furthermore, because all combined-cycle plants in the SIC use the same pipeline to obtain their natural gas supplies from Argentina, a disruption of this supply would materially increase prices in the spot market. The reliance on the spot market to purchase electricity could have a material adverse effect on Electrica Santiago.

On May 3, 2005, a bill to amend the Electric Law was approved by the Chilean Congress which was promulgated by the executive branch on May 19, 2005 (Law No 20.018). The bill was designed to mitigate the effects of the restrictions on natural gas exports to Chile which have been applied by the Argentine government since March 2004. The main aspects of Law 20.018 include:

- implementation of public bid processes for distribution companies after 2009;
- modification of regulated node price methodology, progressively replacing the node price with public bid prices and improvement in the correlation between regulated node prices and unregulated market prices in the interim period;
- stabilization of generation companies revenues by allowing them to enter into long-term fixed price contracts with distribution companies (maximum of 15 years);
- authorization of voluntary savings incentives which allow generation companies to directly negotiate demand reductions with final customers;
- determination that natural gas shortages can no longer be considered force majeure events and compensation to customers by generation companies which fail to operate due to gas shortages; and
- establishment of compensation for losses by generation companies when obligated to sell to distribution companies that are unable to independently contract adequate supplies.

China. The Chinese government is in the process of implementing a fundamental long-term restructuring of the electric power sector, embodied in the National Power Industry Framework Reform Plan (the Reform Plan) promulgated by the State Council in April 2002. The key elements of this plan involve separation of generation and transmission, and the introduction of market-driven competition into China s electric power industry whereby generators will be required to compete in the market for their output, with a system of competitive bidding for on-grid tariffs.

As a result of the restructuring, a new industry regulator, China s National Electricity Regulatory Commission (China s NERC) was established. The responsibilities of China s NERC include: promulgating operating rules for the electric power industry; supervising the operation of the electric power industry and safeguarding fair competition; monitoring the quality and standard of production by electric power enterprises; and issuing and administrating electric power service licenses.

The surge in economic growth over the last three years increased the demand for electric power, which has outpaced previous demand forecasts, leading to a shortage of generating capacity and even load-shedding in some areas. The strong growth in electricity demand has caused the government to delay or slow the pace of moving towards a competitive market. However, it is expected that supply and demand in China will reach equilibrium in 2006, with some regional power grids experiencing supply surplus in 2007. The ultimate adoption of the Reform Plan may result in market and regulatory changes.

In April 2005, with a view to implementing the power industry reform, the National Development and Reform Commission released an interim regulation governing on-grid tariffs, along with two other regulations governing transmission and retail tariffs. All three came into effect on May 1, 2005 (Interim Regulations). Pursuant to the Interim Regulations, prior to adoption of a pooling system, 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 independent power producers to cover reasonable costs and to obtain reasonable returns. However, it further defined that the generation costs shall be the average costs in the industry and reasonable returns shall be formulated on the basis of interest rate of China s long-term treasury bond plus certain percentage points. Furthermore, the Interim Regulations provided that, after adoption of a pooling system, the on-grid tariffs shall comprise two components: capacity charge and energy charge. The capacity charge shall be determined by the pricing authorities based on the average investment costs in the same regional power market; and the energy charge shall be determined through market competition. There is also a provision to allow the on-grid tariffs to be pegged to the fuel price in the case of significant fluctuations in fuel price. It is unclear whether these Interim Regulations will have a material adverse effect on our businesses.

Colombia. In 1994 the Colombian Congress issued the laws of Domiciliary Public Services and the Electricity Law, which set the institutional arrangement for the electric sector and the general regulatory framework. The Regulatory Commission of 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 control function was assigned to the Superintendency of Public Services. The Mining and Energy Planning Unit (UPME) develops plans for the energy sector. These plans are then adopted by the Ministry of Mines and Energy. The general regulatory framework established free access in the networks, free entrance in the business, the creation of a wholesale market, the unbundling of activities, the principles for setting formulas for tariffs and the free selection of the provider by the consumer, among others.

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 offers its availability quantities for a 24 hour period with one price set for those 24 hours. The dispatch is arranged by price merit and the spot price is set by the marginal unit. The system is one node.

The spot market started in July 1995, and in 1996 a capacity payment was introduced for a term of 10 years. This payment is US$5.25 kW-month, and it is assigned through an administrative and centralized hydro/thermal dispatch model based on the calculated firm capacity that is needed to be generated under extremely dry conditions. This capacity payment is reflected in the spot market as a floor of the generators bids of approximately US$12/MWh. Although the 1996 capacity factors for hydro plants were based on the worst historical El Niño situation, in 2000 CREG recalculated these capacity factors based on a theoretically more severe hydrology condition. This regulatory change reduced the firm capacity

remuneration of AES-Chivor for that year from 485 MW to 304 MW. Our company and other hydro generators initiated litigation for this reason. The current remuneration for 2006 is 290 MW.

CREG has released an outline of a proposal that would replace this administrative process for firm capacity payments, and instead have a more market based system, in which capacity payments would be determined through auctions of energy options. CREG has not yet released sufficient detail of this new proposal to evaluate the effect it would have on the Company.

Bilateral contracts between a generator and suppliers are treated as financial instruments which are settled by the Market Administrator. These contracts are normally either take or pay or take and pay agreements, and normally have a term of one to three years. There is no regulatory obligation for an electricity supplier to hedge its consumers demand, and the negotiation of energy contracts between generators and suppliers for unregulated customers is unrestricted. The contracts to supply energy to regulated (small) consumers must be assigned by the Load Servicing Entities (LSE) through a public bidding process to determine the lowest offer.

Dominican Republic. The electricity sector in the Dominican Republic has evolved from a state owned system, to a reform period from 1997 through 1999 which was regulated by the Ministry of Industry and Commerce without an overall plan, and finally, with the passage of the General Electricity Law No. 125-01 on July 26, 2001, and its regulations, into a system with more concise rules, along with new institutions to formulate energy policy and regulate the sector, governed by the Energy National Commission (CNE) and the Superintendancy of Electricity (SIE). However, some of the new resolutions adopted by SIE are in conflict with the regulations created by the Ministry of Industry and Commerce prior to enactment of Law 125-01.

During 2004, the Dominican Republic was shaken by a severe economic, financial and political crisis, caused mainly by the status of the public finances and the bankruptcy of the three main commercial banks. Although the electricity sector has been vulnerable for years, it was this economic downturn and an increase in fuel prices that essentially caused a financial crisis in the Dominican Republic electrical sector. Specifically, 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 generators for electricity generated. There are no assurances that these issues will be resolved in favor of the Company.

The election of a new presidential administration in August 2004 has been accompanied by progress towards addressing the crisis in the electricity sector. Negotiations have intensified between the government, the multilateral lending and development agencies such as the IMF and the World Bank and the private electricity sector. The key issues that are the focus of these negotiations include (i) the failure to provide for full pass through of the costs of electricity supply to consumers; (ii) the failure of the regulator to follow through on subsidy commitments, which has put the distribution companies in the position of effectively financing portions of the subsidy programs; and (iii) the fiscal deficit of the government that requires multilateral lending to reconstitute the sector.

During 2005, the government has been paying both the subsidies and its own energy bills on time; the tariff has been modified to recognize the fuel generation basket, and there is increased support for fraud prosecution. Despite this improvement over prior years, the electricity sector has not completely recovered from the financial crisis of 2004. Last year it needed US$500 million to cover the current operations, and for 2006 it will need another US$500 million, which indicates that the electricity sector in the Dominican Republic remains fiscally unstable, so that additional reforms may be needed.

El Salvador. In 1996, the government of El Salvador began the process of privatizing, modernizing and restructuring El Salvador s electricity industry in order to create an open and competitive electricity sector with the support of strategic foreign investors. To accomplish its goal, the government created a new regulatory framework through the enactment of the Electricity Law in October of 1996, as subsequently amended in June 2003. The Electricity Law regulates the generation, transmission, marketing, distribution and supply of electricity in El Salvador and provided the basis for private sector participation and competition in the Salvadoran energy sector, the unbundling of electricity generation, transmission and distribution, the privatization of electricity distribution and generation assets and the creation of a transparent regulatory structure.

From 1986 to 1998 CEL, a Salvadoran state-owned entity, generated, transmitted and distributed all of El Salvador s electricity on a monopoly basis. All planning, regulatory and executive functions concerning electricity generation, transmission and distribution were vested in CEL. Under the Electricity Law, an independent regulator, SIGET, was established, and CEL was required to reorganize its generation, transmission and distribution assets to facilitate privatization. CEL separated its generation, transmission and distribution activities from one another and further divided its generation and distribution activities into operationally independent companies for purposes of privatization.

El Salvador has five electricity distribution companies, created from CEL s distribution assets, which were privatized in 1998. AES controls four of these five distribution companies: CAESS, CLESA, EEO, and DEUSEM. In preparation for their privatization, each of these companies absorbed elements of CEL s rural electrification activities that were situated near their networks.

The government has recently adopted certain revisions and adjustments to the regulatory system created by the Electricity Law, and additional modifications are under consideration. The government is studying how to further separate the activities of CEL and ETESAL, the transmission company that is owned by CEL, with the goal of privatizing ETESAL. In addition, new Salvadoran regulations have been recently issued aimed at facilitating the entry of electricity traders into the electricity market and improve the transparency of the pricing signals in the wholesale market.

In June 2003, the government amended the Electricity Law to grant greater regulatory authority to SIGET and to create a compensatory fund in the wholesale market to promote stability in the price of energy on the spot market. SIGET has recently prepared norms and guidelines in the form of a manual which will set minimum standards for electricity distribution companies for system design, distribution losses and costs, as well as service quality and reliability. In addition, as part of the Company s regular upcoming five-year tariff review process, SIGET is reviewing the characteristics of the demand curve for each of the Company s electricity distribution networks, in order to be able to better analyze and review the Company s proposed tariffs.

During 2005, the Ministry of Economy (*Ministerio de Economía*) proposed revising the dispatch rules for El Salvador s electricity market from a bidding to an economic dispatch basis. If this reform is adopted in the future, it may adversely affect the Company s ability to continue to generate margins on the energy they buy and sell for their customers.

European Union. European Union (EU) legislation is required to be implemented in each of the EU member states, 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 on 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 European Union (EU), including the Czech Republic, Hungary, the Netherlands and the United Kingdom.

The principles of market liberalization in the EU electricity and gas markets were introduced under the Electricity and Gas Directives (Directive 1996/92/EC and Directive 1998/30/EC, respectively). In 2005, the European 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 problems related to price formation in the electricity wholesale markets

29

and the role of long term agreements as a possible barrier to entry with a view to improving the competitive situation. The Hungarian Competition Authority launched a parallel inquiry into the national electricity and gas market and announced its preliminary findings in late 2005. These findings identified long term contracts as a potential source of competition concern, in addition to other obstacles, such as having a single power buyer, MVM. The European Commission (EC) is presently analyzing the results of its inquiry, and has yet to decide what formal steps if any they will take with respect to their preliminary analyses. It is therefore too early to predict the concrete impact of the EC sector inquiry or the Hungarian Competition Authority s inquiry into AES businesses in the EU.

The EC has also introduced environmental legislation which impacts the electricity sector in general and includes:

- The EU Directive on Integrated Pollution Prevention and Control (1996/61/EC) (IPPC Directive) which requires member states to prevent or reduce pollution from a range of installations including electricity generation stations and introduces a permit regime to ensure the prevention or reduction of pollution from such installations.

- The Large Combustion Plants Directive (2001/80/EC) (LCPD) which introduced a regime for the reduction of emissions sulphur dioxide, nitrogen oxides and particulates from large combustion plants, with increased restrictions coming into effect in two phases from 2008 and 2016, respectively.

- The Renewables Directive (2001/77/EC) which deals with the promotion of electricity generated from renewable sources and sets a target of 12% of electricity consumed in the EU to be generated from renewable sources by 2010.

- The EU Emissions Trading Directive (2003/87/EC) which, amongst other things, established the EU Emissions Trading Scheme (EUETS) in respect of emissions of carbon dioxide effective January 1, 2005.

Progress in the 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 Air Emissions below, for a description of these Directives.

Hungary. In 2004, in connection with the accession of Hungary as a member state of the European Union, the Hungarian government provided notification to the European Commission of certain legislative arrangements concerning compensation to the state owned electricity wholesaler, MVM. The Commission conducted a preliminary investigation to determine whether or not any alleged government aid was provided through MVM to its suppliers which was incompatible with the common market. The Commission has decided to open a formal investigation. AES Tisza is not a named party to the investigation, but could be adversely affected in the event that the Commission was to conclude that AES Tisza was one of the beneficiaries of unlawful state aid by virtue of its power purchase arrangements with MVM. As an interested party, AES Tisza will have the opportunity to make submissions to the Commission in relation to the investigation. It is currently too early to predict the outcome of the formal investigation.

In 2006, the Hungarian government enacted legislation to amend the Hungarian Electricity Act (Act 110 of 2001) to enable, amongst other things, the application of regulatory pricing to the sale of electricity by generators to the state owned utility wholesaler, MVM. No implementing legislation or regulations have yet been enacted and it is therefore too early to predict the impact of this legislation.

India. In 2003, the Government of India enacted Electricity Act 2003 (New Act) to establish a framework for a multi-seller-multi-buyer model for the electricity industry, and introduced significant change in India s electricity sector. These changes included:

- Generation, excluding hydro and nuclear, is delicensed. Generation companies can sell power to a customer of its choice;
- Transmission, immediate non-discriminatory open access is allowed;
- Distribution, open access will be implemented in phases;
- Trading is recognized as a licensed activity; and
- All states are required to establish an electricity regulator.

In March 2004, the Central Electricity Regulatory Commission (CERC) issued terms of conditions for tariff determination for generation and transmission. In early 2004, the Government of India issued Guidelines for Determination of Tariff by Bidding Process for Procurement of Power by Distribution Licensees. In February 2005, the Government of India came out with the National Electricity Policy and in January 2006 published the National Tariff Policy (together Policy).

The Policy established deadlines to implement provisions of the New Act: June 2005 was the deadline for the state regulators to notify regulation for open access to 1 MW; June 2006 is the deadline for technology upgrades to facilitate open access in transmission; and March 2007 is the deadline for Electricity Regulatory Commission of the respective States (SERC) to ensure energy audits.

The Policy recommends Multi-Year Tariffs (MYT) but without any deadline for implementation. The Policy also advocates rationalization of tariffs but without focusing on removal or reduction of cross subsidies. The Policy recognizes the need for private investment to meet full demand for power by 2012, but does not specify specific measures to attract private capital.

India s power sector is regulated by CERC at the national level and by SERCs at the state level. CERC is responsible for interstate transmission and generation for more than one state. SERCs are responsible for electricity and intra-state transmission tariffs. The Government of India assists states in arranging financing for restructuring of state utilities for financial turnaround. However, actual implementation of the reform process is entirely contingent on the state governments and regulators. Although the New Act and the Policy advocates regulators be independent, and develop transparency and political insulation, the regulatory environment and risks could be substantially different across States. It is not clear whether existing and concluded power purchase agreements are subject to re-opening by regulatory bodies. If re-opened, the review could have an adverse impact on OPGC, our generation facility in India.

Kazakhstan. The Kazakhstan Parliament and Government have implemented a series of regulatory normative acts to encourage competition in wholesale and retail electricity markets. Under the present regulatory structure, the electricity generation and supply sector in Kazakhstan is mainly regulated by the government, acting through the Ministry of Energy and Mineral Resources and its committees (the Ministry), the Committee for protection of competition of the Ministry of Industry and Commerce (the Committee) and the Agency for regulation of the natural monopolies (the Agency), that have the necessary authority for the supervision of the Kazakhstan power industry.

The Ministry s main function is to supervise the appropriate implementation of the normative and sub-normative acts, rules and regulations, ensure the efficiency of the wholesale and retail markets of electricity, and ensure the efficient and economic supply of energy to consumers by monitoring market conditions and ensuring adherence to market rules by market participants. The Ministry s core areas of responsibility that directly relate to AES s businesses in Kazakhstan are: competitive economic regulation of the wholesale and retail market of heat and electricity supply, legislative regulation of the businesses

within the scope of normative rules and regulations, and consultative assistance of the businesses within the authority granted by the normative acts.

The newly created Committee is an authorized state agency which exercises control over monopolistic activity and the protection of the competition on the wholesale and retail markets of the electricity supply and to coordinate and approve tariffs. The Agency s main function is to approve and regulate the tariffs of the naturals monopolists, the tariffs estimation and discount policy, approval of the compensation tariff and to supervise the activity of the natural monopolists with respect to their tariffs policy.

Ust-Kamenogorsk CHP (UK CHP), together with the two hydro plants we operate on a concession basis, Ust-Kamenogorsk (UK Hydro) and Shulbinsk (Shulbinsk Hydro), have been under jurisdictional control of the Agency since 2003 because their aggregated share in the electricity supply commodity market in the Eastern Kazakhstan oblast is 70%. As such, these businesses are required to notify the Agency about the future price increases for monopolistic commodities (works, services) and the reasons for such price increase. Currently, the Agency is authorized to regulate prices, and to date, all requested price increases have been deemed to be excessive by the Agency.

Power generating entities (UK CHP and our hydro power plants) are required to participate in the centralized trade of electric power. Up to 30% of generated electricity is supposed to be sold via these centralized auctions. Since UK CHP, UK Hydro and Shulbinsk Hydro are deemed to have dominating positions (monopolies), they must get Agency approval for price increases one month in advance, and are therefore disqualified from participating in the centralized auctions (since prices are not set in advance).

Two of our companies that participate in both the wholesale and retail markets as energy sellers are Nurenergoservice LLP and AES Kazakhstan LLP. Although they are not regulated by the antimonopoly legislation or the legislation on the natural monopolies, due to their indirect affiliation with AES generation companies in Eastern Kazakhstan, AES Kazakhstan LLP and Nurenergoservice LLP comply with the antimonopoly legislation when entering into contracts with our generators. During the last two years there were several attempts by the antimonopoly bodies to recognize some contracts as invalid on the grounds of artificially increasing tariffs of the generators by using AES Kazakhstan as an intermediary company.

Mexico. In 1992, the Electric Energy Public Service Law (*Ley del Servicio Público de Energía Eléctrica)* (the Energy Law) was amended to allow national and foreign private investment participation in the energy generation segment through the following independent-generation forms: self-supply, cogeneration, small production, independent production for sale to the Federal Electricity Commission (*Comisión Federal de Electricidad)* (CFE) and generation for export derived from cogeneration, independent production and small production.

The government entities involved in power generation projects are the Ministry of Energy (*Secretaría de Energía*), which is in charge of developing the relevant policies on energy matters, the Energy Regulating Commission (*Comisión Reguladora de Energía*) (CRE), which acts as the sector regulator and the CFE, which provides the electric energy public service and owns and operates the national electric system.

The CRE has the authority to grant or revoke permits and authorizations required by private investors to generate electricity in Mexico. The CRE must approve tariffs for the sale of energy to CFE for public distribution, as well as the prices for the transmission and delivery of electricity.

The federal government intends to promote private participation in power generating plants, and to this end has allowed independent power producers to present bids for the purchase of capacity and power. The government seeks what it deems to be a reasonable balance between private and public investment in generating plants.

Independent power production in Mexico has increased considerably in the past years. In 2002, 7% of the national total of electric power was produced by independent producers, in 2003, the percentage increased to 19% and in 2005 to 33%. Installed capacity in independent power production plants has also increased, as has reserve capacity which has grown over 40% in the last six years.

Oman. Prior to May 2005, the Ministry of Housing, Electricity and Water (MHEW) owned all electricity and related water infrastructure in Oman, with exception of a few independent power producers (IPP) and independent power and water producers (IPWP). MHEW was responsible for the operation and maintenance of the government owned generation plants and the entire transmission and distribution system. Consequent to promulgation of a Sector Law in July 2004 (effective August 2004) the electricity sector was unbundled and divided into newly created corporate entities. A new Regulatory Authority was formed to oversee the Power sector. The Authority was to promulgate rules and subsequently grant generation licenses to all the generating companies in Oman. AES Barka was granted its generation license in May 2005 after complying with all the requirements of the regulator. Furthermore, an Electricity Holding Company was also incorporated to hold the Government s stake in its generation assets and newly unbundled companies. As a result of the unbundling, nine (9) other companies were formed, comprised of one off-taker for all the electricity and water production in Oman, one transmission company, three generation companies for the government owned plants, and four distribution companies. The existing market continues to be comprised of fully contracted entities and no change in this structure is envisioned, especially for presently contracted facilities, at this time.

Pakistan. The electricity sector in Pakistan is regulated by three main entities, namely the Water and Power Development Authority (WAPDA), the National Electric Power Regulatory Authority (NEPRA) and the Private Power Infrastructure Board (PPIB).

WAPDA acts as a power off-taker. In 1992, the government of Pakistan approved WAPDA s Strategic Plan for the Privatisation of the Pakistan Power Sector. This Plan sought to meet three critical goals: a) enhance capital formation, b) improve efficiency and rationalize prices, and c) move over time towards full competition by providing the greatest possible role for the private sector through privatization. A critical element of the Strategic Plan was the creation and establishment of a Regulatory Authority to oversee the restructuring process and to regulate monopolistic services. In December 1997, The Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997, became effective.

NEPRA was created to introduce transparent and judicious economic regulation, based on sound commercial principles, to the electric power sector of Pakistan. NEPRA s main responsibilities are to: a) issue licenses for generation, transmission and distribution of electric power; b) establish and enforce standards to ensure quality and safety of operation and supply of electric power to consumers; c) approve investment and power acquisition programs of the utility companies; and d) determine tariffs for generation, transmission and distribution of electric power.

NEPRA regulates the electric power sector to promote a competitive structure for the industry and to ensure the co-ordination of reliable and adequate supply of electric power in the future. By law, NEPRA is mandated to ensure that the interests of the investor and the customer are protected through judicious decisions based on transparent commercial principles and that the sector moves towards a competitive environment.

PPIB was established in 1994 to offer support by the government of Pakistan to the private sector in implementing power projects. PPIB provides a One-Window facility to investors in the private power sector by acting as a one stop organization on behalf of all ministries, departments and agencies of the Government of Pakistan in matters relating to developing and expediting the progress of power projects in the private sector, either through competitive bidding or through proposals submitted by interested parties. PPIB s functions include the following:

a) to negotiate the interconnection agreements and provide support in negotiating power purchase agreements, fuel supply agreements, water use licenses, and other related agreements;

b) to provide guarantees to independent power producers for the performance of government of Pakistan entities;

c) to prepare, conduct and monitor litigation and international arbitration for, and on behalf of Pakistan for private power projects and proposals; and

d) to assist NEPRA in determining and approving tariffs for new private power projects.

Panama. In 1995, Panama initiated the reform of its electricity sector with the passage of legislation allowing private participation in power projects. This was followed in 1996 by the Public Services Regulatory Agency Law, which established new institutional arrangements for the regulation of public services, including electricity. In 1997, the Electricity Law was passed, calling for the restructuring of the Instituto de Recursos Hidráulicos y Electrificación (IRHE), the Panamanian government agency responsible for electricity generation, transmission and distribution. IRHE was divided into three distribution companies, four generation companies and one transmission company for privatization.

In 1998, the three distribution companies were privatized, and were each granted 15-year concessions. The same year, the four generation companies were privatized, with the hydropower generators receiving 50-year concessions granting the use of water, and the thermal power generators receiving 40-year licenses. The transmission company remains under state ownership.

The dispatch of the system is the responsibility of the Centro Nacional de Despacho (CND), which is part of the transmission company, Ente Regulador de los Servicios Públicos (ETESA or the Regulator). There is a surcharge levied on revenues in the system to cover the administrative costs of the CND and ETESA, which helps to promote the Regulator s political independence.

The regulatory framework establishes the operation of generation plants on a merit-order dispatch basis. Dispatch priority is determined based on audited variable operating costs with the last unit dispatched determining the marginal cost of the system. Hydroelectric plants are dispatched in such a way as to optimize the use of water.

The Panamanian electric system operates with both contract and spot markets. At the time of privatization, the distribution companies were assigned PPAs with each of the generators, sufficient to meet the generators peak energy demand requirements. The cost of electricity with respect to spot market purchases and PPAs approved by the electric industry regulator (including initial and new contracts) are a direct pass-through to residential and industrial users. The system is designed to preserve the financial health of the distribution companies and the entire electricity sector. Distribution companies are required to contract 100% of their annual energy requirements (although they can self-generate up to 15% of their demand), reducing uncertainty for generators and consumers.

In the recent years, certain changes have been made to this system. The Panama Canal Authority, a government company, is competing in the electricity generation market under different rules that give the Canal Authority advantages over private generators. The Regulator is trying to put caps on electricity prices and the distribution companies are trying to have the 15% cap on generation removed. Tariffs were increased in 2003 and 2004, which prompted the government to subsidize the 2005 tariff increase. Although the government decided to halt these subsidies in 2006, they have recently suspended the scheduled tariff increase for 90 days, while the government reviews a proposed bill to modify the law.

Qatar. In the State of Qatar there is no regulatory authority. Generation licenses are granted by the State of Qatar.

The Government is moving steadily away from the former pattern of electricity supply being seen as the function of a State Ministry. The creation of Qatar Electricity and Water Company (QEWC) in 1998 was the first key step in this process. More recently, the former Ministry of Electricity and Water has been transformed into a state owned Corporation called the Qatar General Electricity and Water Corporation (KAHRAMAA).

It is envisaged that KAHRAMAA will continue to be responsible for the bulk purchase of power from QEWC and other generators, while also managing the control and dispatch of the national grid and local reticulation systems.

Ukraine. Restructuring of the Ukrainian electrical energy sector began in 1995. Until that time the electrical energy sector was functioning as a single vertically integrated system operated by the Ministry of Energy and Electrification. In April 1995, the President of Ukraine issued Decree No. 282/95 On the Restructuring in Electrical Energy Complex of Ukraine, by which the vertically integrated system was separated into generation, local distribution and high voltage transmission. The local distribution and supply services were placed into 27 regionally defined operating companies (called oblenergos). The Ministry of Energy and Electrification remained as a policy agency, and also controlled shares (assets) of state joint stock companies.

In March 1995, the President of Ukraine created the National Regulatory Energy Commission (NREC), the main purpose of which was to ensure the effective functioning of the electric energy sector and the formation of an electric energy market.

In 1996, NREC approved the Wholesale Electricity Market (WEM) Members Agreement. As a result, transactions for power and energy sales from the generating companies to the supply companies were structured through a wholesale electricity market modeled on the early version of the British power pool.

The Law of Ukraine On the Energy Sector adopted in 1997, became the first legislative act regulating electricity generation, transmission, supply and consumption, competition, customers rights protection and energy safety. In June 2000, amendments to the Law of Ukraine On the Energy Sector were passed, which obligated customers to make cash payments for consumed electricity into special bank accounts. Allocations of funds from the special bank accounts to sector entities are made based on a fund allocation procedure issued by the NREC. By the end of 2004, cash collections had recovered to approximately 97% from 27% in 2000.

In 2002, the Cabinet of Ministers of Ukraine approved the Concept of WEM Development, laying out foundations for further market development in three stages over several years, leading to replacement of the current single buyer market model with bilateral contracts between suppliers and generators, and between end-users and generators, as well as a balancing market. In order to improve the overall investment climate, the Concept also addressed power sector problems such as administrative interference in market operations and cash flows, cross-subsidization through retail and wholesale tariff structures, non-payment and debt accumulation. In June 2004, a special commission created by the government approved a plan of measures for the WEM Concept Implementation. The plan set out a list of legislative acts, which have to be drafted or amended, and responsible agencies for that work.

In 2004, the Cabinet of Ministers of Ukraine created the national energy holding company, Energy Company of Ukraine (ECU), which holds state owned shares in Ukrainian thermal and hydro generation companies as well as electricity distributors, an export operator and others, with the exception of high voltage and interstate network operator. ECU controls the operational activity of those energy companies, where the government owns controlling shares, the role previously performed by Ministry for Fuel and Energy.

At the end of 2005, the Cabinet of Ministers transferred the powers for managing ECU and another state holding company gas monopolist Naftogas to the Ministry of Fuel and Energy (MFE) such that the MFE is now in charge of the electricity, nuclear and gas sectors.

In 2005, the NREC approved and implemented a system of uniform electricity tariffs for end users. The uniform tariff mechanism is aimed at the equalization of retail electricity prices for each non-residential customer within the same voltage-class, removing regional price differentiation across all regions of Ukraine. The new end user pricing system does not change the methodology for calculating distribution and supply tariffs. Starting in September 2005, a phased in introduction of uniform tariffs began. The system results in reallocation of part of electricity payments from customers of rural areas to those of industrial areas. Any surplus or deficiency of each distributor s revenue that results from the uniform tariffs is offset through the wholesale market price adjustment mechanism; thus, the uniform tariff should not affect each distributor s margin. However, the NREC has put a cap on customer tariff increases and thus, uniform tariffs are in reality not yet uniform country wide.

In 2005, the wholesale electricity market price increased approximately 30% due to the increase in the fuel prices in the country and changes in the pricing arrangements for thermal generating companies. Most of this growth took place in the second half of the year, after the presidential elections.

In late 2005, the government indicated it intends to increase electricity tariffs for residential customers. Such tariffs have been fixed since 1999. It is expected that tariffs will be increased some time in 2006 by at least 20% of the current level.

In 2005, a new law came into force introducing a comprehensive set of measures to resolve Ukraine s energy sector debts problem. The law introduces (a) a set of standardized measures, such as offsets through the supply chain, receivables write-offs with no tax consequences, and payables restructuring guidelines, (b) incentives for implementation thereof and (c) an organizational framework within which implementation of the mechanisms will take place. For AES Ukraine, the new law will allow it to resolve currently existing doubtful receivables through a supply chain offset against the residual restructured payables to the wholesale energy market.

In July 2005, the government issued a special resolution for which government debts to the population resulting from the default of Soviet banks may be offset against debts for purchased electricity. From AES Ukraine s perspective, this resolution will allow it to offset part of doubtful residential customers receivables against its payables to the WEM for purchased power.

United Kingdom. ***AES Kilroot in Northern Ireland is subject to the regime established by the LCPD and will therefore be required to*** comply ***with the increased restrictions on emissions imposed under that regime. It is also required to obtain a permit under the IPPC Directive to enable it to continue to operate. AES Kilroot will be implementing modifications to ensure that the plant complies with the requirements of the LCPD and the IPPC Directive.***

AES Kilroot is subject to regulation by the Northern Ireland Authority for Energy Regulation (NIAER). Under the terms of the generating license ***granted to AES Kilroot, the NIAER has the right to review and, subject to compliance with certain procedural steps and conditions, require the early termination of the long term power purchase agreements under which AES Kilroot currently supplies electricity to Northern Ireland Electricity (NIE) in 2010.***

Venezuela. The Electric Service Law, enacted on December 31, 2001, contemplates the restructuring of the entire regulatory system for the electric sector in Venezuela by defining separation of activities and the functions of some of the current entities that regulate the sector, introducing new entities and eliminating others that had regulatory authority over the electric sector. The implementation of this new regulatory regime has been gradual. Certain elements of the old regulatory regime will remain, particularly the tariff regime, while the new entities and regulations to be created under the Electric Service Law are being adopted.

On December 14, 2000, the Government issued regulations which provide the mechanism for the implementation of the Electric Service Law and establish the general regulatory framework for Venezuela s electricity sector relating to, among other things, the free market for generation, the segregation of generation, transmission, distribution and commercialization activities, concessions for existing distribution companies and public auctions for new distribution concessions. The Ministerio de Energia y Petroleo (MEP) is the principal regulatory authority of the electric sector in Venezuela. The MEP is responsible for, among other things, coordinating the activities of the government bodies responsible for administering the regulatory system of the electric service, planning the development of the electric sector, granting concessions for distribution and transmission activities and executing the respective contracts and, in conjunction with the Ministerio de Industrias Ligeras y Comercio (MILCO), adopting tariff rates for distribution activities. The Electric Service Law also contemplates the creation of the Comisión Nacional de Energía Electrica (CNEE) to regulate the electricity sector in Venezuela. The CNEE is expected to be an agency under the MEP with functional, administrative and financial autonomy. Once established, it is expected that the CNEE will gradually take over the functions now being conducted by the Fundación para el Desarrollo del Servicio Eléctrico (FUNDELEC). The Electric Service Law also contemplates the creation of a centralized, state-owned company, the Centro Nacional de Gestión del Servicio Eléctrico (CNGSE), to administer the dispatch of electricity nation-wide. The CNGSE will replace the functions that have been historically assumed by the electricity companies through the Interconnection Contract and administrated by the Oficina de Planificación del Sistema Interconectado (OPSIS). While the CNGSE is being organized, OPSIS will continue to operate and control the dispatch of electricity under the terms of the Interconnection Agreement.

The Electric Service Law introduces a complete revision of the manner in which electric services are to be remunerated. According to the Electric Service Law, distribution and transmission activities will be regulated and their remuneration will be governed by a tariff regime to be implemented by the MEP in conjunction with MILCO. The Electric Service Law provides that, until a new tariff regime is put in place by the MEP, the current tariff regime, set forth in Decree 368 and the 1999 Resolution, will continue to be in effect. These basic tariff rates are subject to semi-annual and monthly adjustments to reflect changes in the inflation and currency exchange rates and the prices of energy and combustible fuels, respectively. However, since price controls were established in the country in 2004, the Government has not permitted EDC to adjust its tariff rates to reflect inflation and devaluation. The adjustment factor to correct fuel and energy prices and quantities is still being implemented monthly.

The failure by the Government in future periods to allow EDC to adjust its tariff rates could have a material adverse effect on its financial condition, results of operations, business prospects and, ultimately, its ability to satisfy its obligations. In addition, the tariff review and setting process in Venezuela is subject to political and regulatory uncertainty. No assurance can be given as to the outcome of such process or to the licensing of activities in the energy sector tariff policy formations, the development of a competitive framework, and customers rights protection.

In November 2003, MEP promulgated regulations governing retail activities of distribution companies and their contractual arrangements with customers. Regulations were also promulgated to govern certain technical aspects of the services provided by distribution companies, including signal voltage and frequency and duration of interruptions. These regulations contemplate the gradual implementation by distribution companies of the systems necessary for compliance with the prescribed quality standards and assume the application of appropriate tariff levels to cover the costs of implementing such systems. The service quality regulations seek to provide incentives for distribution companies that come into compliance with the prescribed standards and impose penalties in the event of non-fulfillment. By request of the distribution companies, the MEP has announced the intention to postpone the application of the penalty stage of the quality standards.

Government officers have also announced recently the intention to change the Electric Service Law, and the main changes expected to be proposed are a regulated generation market with competition for expansion projects, making the CNEE more dependent on the central government and changes in the policy toward subsidies for low income customers.

Environmental and Land Use Regulations

Overview. We have ownership interests in generation and distribution assets in the U.S. and many other countries and we are therefore subject to various international, national, federal, 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. Each of the countries in which we do business has laws and regulations governing operation of power generation and distribution assets, including laws relating to the siting, construction, permitting, ownership, operation, modification, repair and decommissioning of, and power sales from, such assets. In addition to such laws and regulations, international projects funded by the World Bank are subject to World Bank environmental standards, which tend to be more stringent than local country standards. AES often has used advanced environmental technologies (such as CFB coal technologies or advanced gas turbines) in order to minimize environmental impacts.

Environmental laws and regulations affecting power generation and distribution are complex, change frequently and have tended to become more stringent over time. We have incurred and will continue to incur capital costs and other expenditures in order to comply with environmental laws and regulations, in particular, with respect to the laws and regulations described below. See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity for more detail. If environmental and land use regulations change in the future, we may be required to make significant capital or other expenditures. There can be no assurance that we would be able to recover from our customers some or all costs to comply with such environmental or land use regulations or that our business, financial conditions or results of operations would not be materially and 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, or interruptions to our operations. While we have at times been out of compliance with environmental laws and regulations, past non-compliance has not resulted in the revocation of material permits or licenses and has not had a material impact on our operations or results.

Air Emissions. The U.S. Clean Air Act and various state laws and regulations regulate emissions of major air pollutants, including sulfur dioxide (SO_2), nitrogen oxides (NOx) and particulate matter (PM) in the U.S. The Environmental Protection Agency s (EPA) rulemaking requiring adjustments to state implementation plans relating to NOx emissions (the NOx SIP Call) resulted in operators of coal-fired electric generating facilities in 21 U.S. states and the District of Columbia either (i) reducing their NOx emissions to levels allocated under the plan or (ii) purchasing NOx emissions allowances from other operators in order to meet allocated emissions levels by May 31, 2004. We are in the process or have completed installing selective catalytic reduction (SCR) and other NOx control technologies at three facilities of our subsidiary, Indianapolis Power and Light (IPL) in response to NOx SIP Call implementation and other proposed air emissions regulations that are discussed in more detail below.

In March 2005, the EPA finalized two rules that will affect many of our U.S. coal-fired power generating plants. The first rule, named the Clean Air Interstate Rule (CAIR), was promulgated on March 10, 2005 and requires significant reductions of SO_2 and NOx emissions from existing power plants located in 28 eastern states and the District of Columbia. The required emission reductions will be in two phases with the first phase beginning in 2009 and 2010 for NOx and SO_2, respectively, and a second phase with additional reductions in both air pollutant emissions beginning in 2015. The second rule, called the Clean Air Mercury Rule, was issued on March 15, 2005 and requires reductions of mercury emissions from coal-fired power plants in two phases. The first phase will begin in 2010 and will require nationwide reduction of coal-fired power plant mercury emissions from 48 to 38 tons per year. The second phase will begin in 2018 and will require nationwide reduction of mercury emissions from these sources from 38 tons per year to 15 tons per year. The Clean Air Mercury Rule also establishes stringent mercury emission performance standards for new coal-fired power plants. The EPA has granted reconsideration on certain aspects of this rule.

To implement the required emission reductions for these two new rules, the states will establish emission allowance-based NOx, SO_2 and mercury emission cap-and-trade programs. While the exact impact and cost of these two new rules cannot be established until the states complete the process of assigning emission allowances to our affected facilities, there can be no assurance that our business, financial conditions or results of operations would not be materially and adversely affected by these new rules.

The New York State Department of Environmental Conservation (NYSDEC) recently promulgated regulations requiring electric generators to reduce SO_2 emissions by 50% below current U.S. Clean Air Act standards. The SO_2 regulations began to be phased in beginning on January 1, 2005 with implementation to be completed by January 1, 2008. These regulations also establish stringent NOx reduction requirements year-round, rather than just during the summertime ozone season. As a result, in order to operate our four electric generation facilities located in New York, installation of pollution control technology will likely be required.

In July 1999, the EPA published the Regional Haze Rule to reduce haze and protect visibility in designated federal areas. On June 15, 2005, 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 proposed amendment to the Regional Haze Rule would require states to consider the visibility impacts of the haze produced by an individual facility, among other factors, when determining whether that facility must install potentially costly emissions controls. States are required to submit to the EPA their regional haze state implementation plans by December 2007. States that adopt the CAIR cap and trade program for SO_2 and NOx are allowed to apply CAIR controls as a substitute for controls required under BART. On June 20, 2005, EPA proposed a rule for an emission trading program under the regional haze program.

Currently, in the United States there are no federal mandatory greenhouse gas emission reduction programs, including carbon dioxide (CO_2), affecting our electricity power generation facilities. The U.S. Congress has debated a number of proposed greenhouse gas legislative initiatives, but to date there have been no new federal laws in this area. Also, individual states and groups of states are also examining possible greenhouse gas emission reduction programs including the State of California and a group of seven northeastern states under an initiative called the Regional Greenhouse Gas initiative (RGGI). Although final legislation or regulations implementing the California and RGGI greenhouse gas emission reduction programs has yet to be enacted, these greenhouse gas-related initiatives may potentially affect AES electric power generation facilities in California, New York, Connecticut and New Jersey. At present, we cannot predict whether compliance with potential future U.S. national, regional and state greenhouse gas emission reduction programs will have a material impact on our operations or results.

In Europe we are, and will continue to be, required to reduce air emissions from our facilities to comply with applicable European Community (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 opt-in, like our AES Kilroot facility in the United Kingdom, must invest in abatement technology to achieve specific SO_2 reductions. Generally, AES s other coal plants in Europe have opted-in but will not require any additional abatement technology to comply with the LCPD.

In July 2003, the EC 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 will be required to implement EC approved national allocation plans (NAPs). Under the NAPs, member states will be 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, there remain significant uncertainties regarding the application of the European Union Emissions Trading System which commenced operation in January 2005. Based on our current analyses, we expect that certain AES businesses will be under-allocated and others will be over-allocated. At present, we cannot predict whether compliance with the respective NAPs will have a material impact on our operations or results.

On February 16, 2005, the Kyoto Protocol to the United Nations Framework Convention on Climate Change (the Kyoto Protocol) became effective. The Kyoto Protocol requires countries that have ratified it to substantially reduce their greenhouse gas emissions including CO_2. AES has generation operations in six countries that have ratified the Kyoto Protocol. Over the course of the next several years, as decisions surrounding implementation of the Kyoto Protocol become more detailed, we will have a better understanding of the impact of the Kyoto Protocol on the Company. At present, we cannot predict whether compliance with the Kyoto Protocol will have a material impact on our operations or results.

Water Discharges. Our facilities are subject to a variety of rules governing water discharges. In particular, we are evaluating the impact of the U.S. Clean Water Act Section 316(b) rule regarding cooling water intake. To protect fish and other aquatic organisms, the rule requires existing steam electric generating facilities to utilize the best technology available for cooling water intake structures. We believe that many of our facilities will be affected by this rule. To comply, we must first prepare a Comprehensive Demonstration Study to assess each facility s effect on the local aquatic environment. Because 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, and may begin as early as 2008 for some of our U.S. plants. At present, however, we cannot predict whether compliance with the 316(b) rule will have a material impact on our operations or results.

Waste Management. In the course of operations, our facilities generate solid and liquid waste materials requiring eventual disposal. With the exception of coal combustion products (CCP), our wastes are not usually physically disposed of on our property, but are shipped off site for final disposal, treatment or recycling. CCP, 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 CCP, 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. We endeavor to ensure that all our solid and liquid wastes are disposed of in accordance with applicable national, regional, state and local regulations.

ITEM 1A. RISK FACTORS

Investing in our company involves a high degree risk. You should carefully consider the risks described below before deciding to invest in our Company.

The Company s disclosure controls and procedures and internal control over financial reporting were determined not to be effective as of December 31, 2005 and December 31, 2004, due to the material weaknesses that existed in our internal control over financial reporting. Our disclosure controls and procedures and internal control over financial reporting may not be effective in future periods, as a result of existing or newly identified material weaknesses in internal control over financial reporting.

As required by the federal securities laws, our management periodically performs an evaluation of our disclosure controls and procedures and conducts an assessment of our internal control over financial reporting. Disclosure controls and procedures are controls and procedures that are designed to ensure that information required to be disclosed by a company in the reports that it files with the SEC under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified by the SEC s rules and forms, and that such information is accumulated and communicated to the chief executive officer and chief financial officer to allow timely decisions regarding required disclosures. Internal control over financial reporting is the process designed by a company s senior management 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.

In performing the assessment at the end of 2005 and 2004, our management identified material weaknesses in our internal control over financial reporting. A material weakness is a deficiency, 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 more than remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. For a discussion of the material weaknesses identified by our management, see Item 9A of this 2005 annual report on Form 10-K.

Due to these material weaknesses, our management concluded that as of December 31, 2005 and December 31, 2004, our Company did not maintain effective control over financial reporting and concluded that our disclosure controls and procedures were ineffective. During our remediation efforts to correct the material weakness that was identified at the end of 2004, errors were discovered in our financial statements which resulted from such material weakness, as well as newly identified material weaknesses. These errors required us to restate our financial statements that were previously filed in our annual report on Form 10-K for the year ended December 31, 2004 and our quarterly report on Form 10-Q for the quarter ended March 31, 2005. To address the material weaknesses, we performed additional analysis and other post-closing procedures in order to prepare our consolidated financial statements in accordance with generally accepted accounting principles. 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. Performing these additional procedures and the need to restate our financial statements also caused us to delay the filing of our quarterly reports for the second and third quarters of 2005 until January 2006, which was well beyond the deadline prescribed by the SEC s rules to file such reports. In addition, during the 2005 year-end closing process, additional errors were identified that required us to restate our 2004 and 2003 financial results. These corrections are included in the 2005 annual report on Form 10-K. The delays in filing our 2004 Form 10-K/A, and restated quarterly reports, as well as the additional errors identified during the year-end closing process caused the 2005 annual report on Form 10-K to be filed after the SEC deadline for the 2005 annual report on Form 10-K, as well.

As a result of not timely filing the quarterly and annual reports with the SEC, we lost our eligibility to offer and sell our securities pursuant to our shelf registration statement on Form S-3 which could impair our ability to access the capital markets in a timely manner. In addition, the restatements and the delay in the filing of our quarterly and annual reports could have other adverse effects on our business, including, but not limited to:

- civil litigation or an investigation 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,

- covenant defaults, and potentially events of default, under our senior secured credit facilities and the indentures governing our outstanding debt securities, resulting from our failure to timely file our financial statements,

- negative publicity, or

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

Because of our decentralized structure and the many disparate accounting systems of varying quality and sophistication at our various businesses throughout the world, there is still extensive work remaining to remedy the material weaknesses in internal control over financial reporting. We have developed a remediation plan and have begun implementing this plan, but we expect that this work will extend throughout 2006 and possibly beyond. We cannot assure you as to when the remediation plan will be fully implemented, nor can we assure that additional material weaknesses will not be identified by our management or the auditors in the future. Until our remediation efforts are completed, we will continue to incur the expense and management burdens associated with the additional procedures required to prepare our consolidated financial statements. There will also continue to be an increased risk that we will be unable to timely file future periodic reports with the SEC, that a related default under our senior secured credit facilities and indentures could occur and that our financial statements could contain errors that will be undetected.

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. 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. In addition, the effect of new, or changes in, accounting policies and practices and the application of such policies and practices could adversely affect our business.

Our high level of indebtedness, and the security provided for this indebtedness, could adversely affect our business and our ability to fulfill our obligations.

At December 31, 2005, we had approximately $17.7 billion of outstanding indebtedness on a consolidated basis, of which approximately $4.9 billion was recourse debt of The AES Corporation and approximately $12.8 billion was non-recourse debt. All outstanding borrowings under our 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 our directly held subsidiaries. Most of the debt of our subsidiaries is pledged by substantially all of the assets of those subsidiaries. This level of indebtedness and related security could have important consequences to us and our investors because it could:

- make it more difficult for us to satisfy our debt service and other obligations,

- increase our vulnerability to general adverse economic and industry conditions,

- require us to dedicate a substantial portion of our cash flow from operations to make payments on our indebtedness, thereby reducing the availability of our cash flow to fund other corporate purposes and grow our business,
- limit our flexibility in planning for, or reacting to, changes in our business and the industry,
- place us at a competitive disadvantage to our competitors that are not as highly leveraged, and
- limit, along with the financial and other restrictive covenants in our and our subsidiaries indebtedness, among other things, our ability to borrow additional funds as needed or take advantage of business opportunities as they arise.

The agreements governing our indebtedness and the indebtedness of our subsidiaries limit but do not prohibit us or our subsidiaries from incurring 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 flow from operations 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 or otherwise raise funds on acceptable terms or at all to refinance our debt as it becomes due.

We have significant cash requirements and limited sources of liquidity.

The AES Corporation, which refers to the AES parent company, requires cash primarily to fund:

- principal repayments of debt,
- interest and preferred dividends,
- acquisitions,
- construction and other project commitments,
- other equity commitments,
- taxes, and
- parent company overhead and development costs.

The AES Corporation s principal sources of liquidity are:

- dividends and 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 our cash requirements and sources of liquidity, please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Capital Resources and Liquidity in this 2005 annual report on 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 and the ability of its subsidiaries to pay dividends. Any number of assumptions could prove to be incorrect and therefore we cannot assure you that these sources will be available when needed or that our actual cash requirements will not be greater than expected. In addition, our cash flow may not be sufficient to repay at maturity all of the principal outstanding under our senior secured credit facilities and our debt securities and we may have to refinance such obligations. We cannot assure you that we will be successful in obtaining such refinancings.

Existing and potential future defaults by project subsidiaries could adversely affect our results of operations and financial condition.

We attempt to finance our domestic and foreign projects primarily under loan agreements and related documents which, except as noted below, require the loans to be repaid solely from the project s revenues and provide that the repayment of the loans (and interest thereon) is secured solely by the capital stock, physical assets, contracts and cash flow of that project subsidiary or affiliate. This type of financing is usually referred to as non-recourse debt or 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. To the extent The AES Corporation becomes liable under such guarantees and other arrangements, distributions received by The AES Corporation from other projects are subject to the possibility of being utilized by The AES Corporation to satisfy these obligations.

At December 31, 2005, we had approximately $4.9 billon of recourse debt and approximately $12.8 billion of non-recourse debt outstanding. At December 31, 2005, The AES Corporation had provided outstanding financial and performance related guarantees or other credit support commitments to or for the benefit of its subsidiaries, which were limited by the terms of the agreements, to an aggregate of approximately $507 million (excluding those collateralized by letter-of-credit obligations discussed below). The AES Corporation also is obligated under other commitments, which are limited to amounts, or percentages of amounts, received by The AES Corporation as distributions from its project subsidiaries. In addition, The AES Corporation has commitments to fund its equity in projects currently under development or in construction. At December 31, 2005, The AES Corporation also had $294 million in letters of credit outstanding and $1 million in surety bonds outstanding, which operate to guarantee performance relating to certain project development activities and subsidiary operations.

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 $138 million at December 31, 2005.

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 s results of operations and liquidity, including, without limitation:

- reducing The AES Corporation s cash flows since the project subsidiary will typically be prohibited from distributing cash to The AES Corporation during the pendancy 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, or
- triggering defaults in The AES Corporation s outstanding debt and trust preferred instruments. For example, The AES Corporation s senior secured credit facilities and outstanding senior notes and junior subordinated notes include events of default for certain bankruptcy related events involving material subsidiaries. In addition, The AES Corporation s senior secured credit facilities include events of default relating to accelerations of outstanding debt of material subsidiaries.

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 facilities in order for such defaults to trigger an event of default or permit an 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 facilities.

Our competitive supply and Latin American operations represent a substantial portion of our assets and have caused and are expected to continue to cause significant volatility in our results of operations and cash flows.

The competitive supply segment of our business and our Latin American operations each experience volatility in revenues and earnings and has had and is expected to continue to cause significant volatility on our results of operations and cash flows. The competitive supply segment s volatility has resulted from volatile electricity prices, which are influenced by peak demand requirements, weather conditions, competition, market regulation, interest rate and foreign exchange rate fluctuations, electricity transmission and environmental emission constraints, the availability or prices of emission credits and fuel prices, as well as plant availability and other relevant factors. Our Latin American operations have experienced significant volatility because of regulatory and economic difficulties, political instability and currency devaluations being experienced in many of these countries.

We do a significant amount of our business outside the United States which presents significant risks.

During 2005, approximately 79% of our revenue was 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,
- expropriation 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 or similar organizations to honor their contracts,
- inability to obtain access to fair and equitable political, regulatory, administrative and legal systems,
- 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.

Furthermore, the ability to obtain financing on a commercially acceptable non-recourse basis in developing nations is difficult. Even when such non-recourse financing is available, lenders may require us to make higher equity investments or provide greater credit support than historically have been the case. In addition, financing in countries with less than investment grade sovereign credit ratings may also require substantial participation by multilateral financing agencies. There can be no assurance that such financing can be obtained when needed.

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

We operate in many foreign environments and such investment in foreign countries may be impacted by significant fluctuations in foreign currency exchange rates. Our exposure to currency exchange rate fluctuations results primarily from the translation exposure associated with the preparation of our consolidated financial statements, as well as from transaction exposure associated with generating revenues and incurring expenses in different currencies. While our 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 an appropriate exchange rate. As a result, fluctuations in the exchange rate of the U.S. dollar relative to the local currencies in which 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 our receipts and expenditures, including debt service expenditures, are not offsetting in any 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 significantly affected by fluctuations in the value of the Argentine peso, Brazilian real, the Dominican Republic peso, the Pakistani rupee and the Venezuelan bolivar relative to the U.S. dollar. Depreciation of the Argentine peso and Brazilian real has resulted in foreign currency translation and transaction losses, while the appreciation of those currencies has resulted in gains. Conversely, depreciation of the Venezuelan bolivar has resulted in foreign currency gains and appreciation has resulted in losses.

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. We believe that capitalized costs for projects under development are recoverable; however, we cannot assure you 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. 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.

Our acquisitions may not perform as expected.

Historically, we have achieved a majority of our growth through acquisitions. We plan to continue to grow our business through acquisitions. Although acquired businesses may have significant operating histories at the time we acquired them, 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, we cannot assure you 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.

Acquisitions have placed, and in the future may place, a strain on our internal accounting and managerial controls. In addition, our acquisitions outside the United States have required, and will require, us to hire personnel with sufficient expertise in U.S. GAAP to timely and accurately comply with our 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.

Most of our contract generation businesses are dependent to a large degree on one or a limited number of customers and a limited number of fuel suppliers.

Most of our contract generation businesses 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 term of the power sales contracts related to our contract generation power plants ranges from 1 to 25 years. Many of these businesses also limit their exposure to fluctuations in fuel prices by entering into long term contracts for fuel with a limited number of suppliers. The cash flows and results of operations of such businesses are dependent on the continued ability of their customers and suppliers to meet their obligations under the relevant power sales contract or fuel supply contract, respectively. Some of contract generation businesses long-term power sales agreements are for prices above current spot market prices. The loss of one or more significant power sales contracts or fuel supply contracts, or the failure by any of the parties to such contracts to fulfill its obligations thereunder, could have a material adverse impact on our business, results of operations and financial condition.

We have sought to reduce this counter-party credit risk for our contract generation businesses 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 contract generation businesses customers do not have, or have failed to maintain, an investment grade credit rating, and our generation businesses 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, we cannot assure you that our efforts to mitigate this risk will be successful.

Competition is increasing and could adversely affect us.

The power production markets in which we operate are characterized by numerous strong and capable competitors, many of whom may have extensive and diversified developmental or operating experience (including both domestic and international experience) 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. There can be no assurance that the foregoing competitive factors will not have a material adverse effect on us.

Our distribution businesses are highly regulated.

Our distribution businesses face increased regulatory and political scrutiny in the normal conduct of their operations. This scrutiny may adversely impact our results of operations to the extent that such scrutiny or pressure prevents us from reducing losses as quickly as we planned or denies us a rate increase called for by our concession agreements. In general, our distribution businesses have lower margins and are more dependent on regulation to ensure expected annual rate increases for inflation, capital expenditures and increased fuel and power costs, among other things. There can be no assurance that these rate reviews will be granted, or occur in a timely manner.

Our ability to raise capital on favorable terms, to refinance existing corporate or subsidiary indebtedness or to fund operations, capital expenditures, future acquisitions, construction of greenfield projects could adversely affect our results of operations.

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, prospects and credit rating of our company in general and/or that of our subsidiary requiring the financing, and
- changes in tax and securities laws which are conducive to raising capital.

Should future access to capital not be available, we may have to sell assets or decide not to build new plants or acquire existing facilities. While a decision not to build new plants or acquire existing facilities would not affect the results of operations of our currently operating facilities or facilities under construction, such a decision would affect our future growth.

Our business and results of operations could be adversely affected by changes in our operating performance or cost structure.

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, 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.

Any of the above risks could adversely affect our business and results of operations, and our ability to meet our publicly announced projections or analysts expectations.

We 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.

We operate a portfolio of electricity generation and distribution businesses in 25 countries and, therefore, we are subject to significant and diverse government regulation. Our inability to predict, influence or respond appropriately to changes in law or regulatory schemes, including our 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 our 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 regulated 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,
- changes in the definition or determination of controllable or non-controllable costs,
- 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.

Our businesses, particularly our businesses in our competitive supply segment, may incur substantial costs and liabilities and be exposed to price volatility as a result of risks associated with the wholesale electricity markets.

Our generation businesses, especially our businesses in the competitive supply segment, sell electricity in the wholesale spot markets. Our regulated utility businesses, and to the extent they require additional capacity our generations businesses, 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.

A significant percentage of our generation facilities, particularly the facilities in our competitive supply segment, operate wholly or partially without long-term power sales agreements. As a result, power from these facilities is sold on the spot market or on a short-term contractual basis, which if not fully hedged may affect the volatility of our financial results. 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 our wholesale power may be limited.

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

- weather conditions,
- seasonality,
- electricity usage,
- illiquid markets,
- transmission or transportation constraints or inefficiencies,
- availability of competitively priced alternative energy sources,

- demand for energy commodities,
- available supplies of natural gas, crude oil and refined products, and coal,
- generating unit performance,
- natural disasters, terrorism, wars, embargoes and other catastrophic events,
- federal and state energy and environmental regulation, legislation and policies,
- geopolitical concerns affecting global supply of oil and natural gas, and
- general economic conditions in areas where we generate which impact energy consumption.

We are a holding company and our ability to make payments on our outstanding indebtedness at the parent company level is dependent upon the receipt of funds from our 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 our revenue generating operations are conducted through our subsidiaries. Accordingly, almost all of our cash flow is generated by the operating activities of our subsidiaries. Our subsidiaries are separate and distinct legal entities and, unless they have expressly guaranteed any of our indebtedness, have no obligation, contingent or otherwise, to pay any amounts due pursuant to our debt or to make any funds available therefore, whether by dividends, fees, loans or other payments. While some of our subsidiaries guarantee our indebtedness under our senior secured credit facility and certain other indebtedness, none of our subsidiaries guarantee, or is otherwise obligated with respect to, our outstanding public debt securities. Accordingly, our ability to make payments on our indebtedness and to fund our other obligations at the parent company level is dependent not only on the ability of our subsidiaries to generate cash, but also on the ability of our subsidiaries to distribute cash to us in the form of dividends, fees, interest, loans or otherwise. Most of our 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 us. In addition, the payment of dividends or the making of loans, advances or other payments to us may be subject to legal or regulatory restrictions. Our subsidiaries in foreign countries may also be prevented from distributing funds to us as a result of restrictions imposed by the foreign government on repatriating funds or converting currencies. Any right we have to receive any assets of any of our subsidiaries upon any liquidation, dissolution, winding up, receivership, reorganization, assignment for the benefit of creditors, marshaling of assets and liabilities or any bankruptcy, insolvency or similar proceedings (and the consequent right of the holders of our 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).

We may not be able to raise sufficient capital to fund greenfield projects in certain less developed economies.

Commercial lending institutions sometimes refuse to provide non-recourse project financing (including financial guarantees) in certain less developed economies, thus we have sought and will continue to seek, in such locations, 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, these institutions may also require governmental guarantees of certain project and sovereign related risks. Depending on the policies of specific governments, such guarantees may not be offered and as a result, we may determine that sufficient financing will ultimately not be available to fund the related project. In addition, we are frequently required to provide more sponsor equity for projects that sell their electricity into the merchant market than for projects that sell their electricity under long term contracts.

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

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. If any of our or our subsidiaries credit ratings were to be downgraded, our ability to raise capital on favorable terms could be impaired and our borrowing costs would increase.

Furthermore, as a result of The AES Corporation s credit ratings and the trading prices of its equity and debt securities, counter parties 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. We cannot provide assurance that such counter parties will accept such guarantees 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.

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) and the Federal Power Act. The recently enacted Energy Policy Act of 2005 (EPAct 2005) made a number of changes to these and other laws that may affect our business. 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 Qualified Facilities (QFs) if certain market conditions are met. Pursuant to this authority the FERC has recently proposed to remove the purchase/sale obligation for all utilities located within the control areas of the Midwest Transmission System Operator, Inc., PJM Interconnection, L.L.C., ISO New England, Inc. and the New York Independent System Operator. 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 QFs may face a more difficult market environment when their current long-term contracts expire.

EPAct 2005 repealed PUHCA of 1935 and enacted PUHCA of 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 may spur an increased number of mergers and 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 Energy Policy Act of 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 regional transmission organizations and independent system operators 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 our 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.

Finally, EPAct 2005 affects nearly every aspect of the energy business and energy regulation. We are still in the process of analyzing the new law s effects, and those effects could have a material adverse effect on our business.

We are subject to material litigation and regulatory proceedings.

We and our affiliates are parties to material litigation and regulatory proceedings. Investors should review the descriptions of such matters contained in this annual report, as well as our other periodic reports we file in the future with the Commission. There can be no assurances that the outcome of such matters will not have a material adverse effect on our consolidated financial position.

Our business is subject to stringent environmental laws and regulations.

Our activities are subject to stringent environmental laws and regulation by federal, state, local authorities, international treaties and foreign governmental authorities. These regulations generally involve emissions into the air, effluents into the water, use of water, wetlands preservation, 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 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 this annual report on Form 10-K under the caption Regulation Matters Environmental and Land Use Regulations. 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 made and will continue to make 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 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 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.

Catastrophic events could adversely affect our facilities and operations.

Catastrophic events such as fires, explosions, terrorist acts or natural disasters such as floods or tornadoes, or other similar occurrences could adversely affect our facilities, operations, earnings and cash flow.

Our business is sensitive to variations in weather and seasonal variations.

The energy business is affected by variations in general weather conditions and unusually severe weather. We forecast electric sales on the basis of normal weather, which represents a long-term historical average. Significant variations from normal weather (such as warmer winters and cooler summers) where our business are located could have a material impact on our results of operations. Storms that interrupt our services to our customers have in the past required us, and in the future may require us, to incur significant costs to restore services.

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 thirteen defined benefit plans, two 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. Our subsidiaries who participate in these plans are responsible for funding any shortfall of pension plan assets compared to pension obligations under the pension plan. Future downturns in the equity markets, or the failure of any of our assumptions underlying the estimates of our subsidiaries pension plan obligations to prove correct, could increase the underfunding of the pension plan. This may necessitate additional cash contributions to the pension plans that could adversely affect our and our subsidiaries liquidity.

See Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates Pension and Postretirement Obligations and footnote 12 to our consolidated financial statements included in this annual report on Form 10-K.

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

The operation of power generation facilities involves many risks, including:

- equipment failure causing unplanned outages,
- failure of transmission systems,
- the dependence on a specified fuel source, including the transportation of fuel, or
- the impact of unusual or adverse weather conditions (including natural disasters such as hurricanes) or
- environmental compliance

Any of these risks could have an adverse effect on our generation facilities. A portion of our generation facilities were constructed many years ago. Older generating equipment may require significant capital expenditures to keep it operating at peak efficiency. 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 the agreement or incurring a liability for liquidated damages.

We may not fully hedge our exposure against changes in commodity prices.

To lower our financial exposure related to commodity price fluctuations, we routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity, fuel requirements and other commodities. 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. However, we may not cover the entire exposure of our assets or positions to market price volatility, and the coverage will vary over time. Fluctuating commodity prices may negatively impact our financial results to the extent we have unhedged positions.

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.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in certain claims, suits and legal proceedings in the normal course of business. The Company has accrued for litigation and claims where it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. The Company believes, based upon information it currently possesses and taking into account established reserves for estimated liabilities and its insurance coverage, that the ultimate outcome of these proceedings and actions is unlikely to have a material adverse effect on the Company s financial statements. It is possible, however, that some matters could be decided unfavorably to the Company, and could require the Company to pay damages or to make expenditures in amounts that could have a material adverse effect on the Company s financial position and results of operations.

In September 1999, a Brazilian appellate state court of Minas Gerais 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. AES investment in CEMIG is through SEB. This shareholders agreement granted SEB certain rights and powers in respect 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 the lower state court enjoined the exercise of Special Rights. In August 2001, the state appellate court denied an appeal of the merits decision, and extended the injunction. In October 2001, SEB filed two appeals against the decision on the merits of the state appellate court, one appeal to the Federal Superior Court and the other appeal to the Supreme Court of Justice. The state appellate court denied access of these two appeals to the higher courts, and in August 2002, SEB filed two interlocutory appeals against such decision, one directed to the Federal Superior Court and the other to the Supreme Court of Justice. In December 2004, the Federal Superior Court declined to hear SEB s appeal. However, the Supreme Court of Justice is considering whether to hear SEB s appeal. SEB intends to vigorously pursue a restoration of the value of its investment in CEMIG by all legal means; however, there can be no assurances that it will be successful in its efforts. Failure to prevail in this matter may limit SEB s influence on the daily operation of CEMIG.

In November 2000, the Company was named in a purported class action suit along with six other defendants, alleging unlawful manipulation of the California wholesale electricity market, allegedly resulting in inflated wholesale electricity prices throughout California. The alleged causes of action include violation of the Cartwright Act, the California Unfair Trade Practices Act and the California Consumers Legal Remedies Act. In December 2000, the case was removed from the San Diego County Superior Court to the U.S. District Court for the Southern District of California. On July 30, 2001, the Court remanded the case to San Diego Superior Court. The case was consolidated with five other lawsuits alleging similar claims against other defendants. In March 2002, the plaintiffs filed a new master complaint in the consolidated action, which reasserted the claims raised in the earlier action and names the Company, AES Redondo Beach, LLC, AES Alamitos, LLC, and AES Huntington Beach, LLC as defendants. In May 2002, the case was removed by certain cross-defendants from the San Diego County Superior Court to the United States District Court for the Southern District of California. The plaintiffs filed a motion to remand the case to state court, which was granted on December 13, 2002. Certain defendants appealed aspects of that decision to the United States Court of Appeals for the Ninth Circuit. On December 8, 2004, a panel of the Ninth Circuit issued an opinion affirming in part and reversing in part the decision of the District Court, and remanding the case to state court. On July 8, 2005, defendants filed a demurrer in state court seeking dismissal of the case in its entirety. On October 3, 2005, the court sustained the demurrer and entered an order of dismissal. On December 2, 2005, plaintiffs filed a notice of appeal. The Company believes that it has meritorious defenses to any actions asserted against it and will defend itself vigorously against the allegations.

In August 2000, the Federal Energy Regulatory Commission (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. The FERC requested documents from each of the AES Southland plants and AES Placerita. AES Southland and AES Placerita have cooperated fully with the FERC investigation. AES Southland is not subject to refund liability because it did not sell into the organized spot markets due to the nature of its tolling agreement. AES Placerita is currently subject to refund liability of $586,000 for sales to the California Power Exchange. The Ninth Circuit Court of Appeals addressed the appeal of the FERC s decision not to impose refunds for the alleged failure to file rates including transaction specific data for sales during 2000 and 2001. Although in its order issued on September 9, 2004 the Ninth Circuit did not order refunds, the Ninth Circuit remanded the case to the FERC for a refund proceeding to consider remedial options. That remand order is stayed pending rehearing at the Ninth Circuit. In addition, in a separate case, the Ninth Circuit heard oral arguments on the time and scope of the refunds. Placerita made sales during the time period at issue in the appeals. Depending on the result of the appeals, the method of calculating refunds and the time period to which the method is applied, the alleged refunds sought from AES Placerita could approximate $23 million.

In August 2001, the Grid Corporation of Orissa, India (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 appears to seek approximately $188.5 million in damages plus undisclosed penalties and interest, but a detailed alleged damages analysis has yet to be filed by Gridco. The Company has counter-claimed against Gridco for damages. An arbitration hearing with respect to liability was conducted on August 3-9, 2005 in India. Final written arguments regarding liability were submitted by the parties to the arbitral tribunal in late October 2005. A decision on liability may be issued in the near future. A petition remains pending before the Indian Supreme Court concerning fees of the third neutral arbitrator and the venue of future hearings with respect to the CESCO arbitration. The Company believes that it has meritorious defenses to any actions asserted against it and will defend itself vigorously against the allegations.

In December 2001, a petition was filed by Gridco in the local India courts seeking an injunction to prohibit the Company and its subsidiaries from selling their shares in Orissa Power Generation Company Pvt. Ltd. (OPGC), an affiliate of the Company, pending the outcome of the above-mentioned CESCO arbitration. OPGC, located in Orissa, is a 420 MW coal-based electricity generation business from which Gridco is the sole off-taker of electricity. Gridco obtained a temporary injunction, but the District Court eventually dismissed Gridco s petition for an injunction in March 2002. Gridco appealed to the Orissa High Court, which in January 2005 allowed the appeal and granted the injunction. The Company has appealed the High Court s decision to the Supreme Court of India. In May 2005, the Supreme Court adjourned this matter until August 2005. In August 2005, the Supreme Court adjourned the matter again to await the award of the arbitral tribunal in the CESCO arbitration. The Company believes that it has meritorious defenses to any actions asserted against it and will defend itself vigorously against the allegations.

In early 2002, Gridco made an application to the OERC requesting that the OERC initiate proceedings regarding the terms of OPGC s existing power purchase agreement (PPA) with Gridco. In response, OPGC filed a petition in the India 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 PPA 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 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 terms, the OERC will likely lower the tariff payable to OPGC under the PPA, which would have an adverse impact on OPGC s financials. The Company believes that it has meritorious defenses to any actions asserted against it and will defend itself vigorously against the allegations.

In July 2002, the Company, Dennis W. Bakke, Roger W. Sant, and Barry J. Sharp were named as defendants in a purported class action filed in the United States District Court for the Southern District of Indiana. In September 2002, two virtually identical complaints were filed against the same defendants in the same court. All three lawsuits purported to be filed on behalf of a class of all persons who exchanged their shares of IPALCO Enterprises, Inc. (IPALCO) common stock for shares of AES common stock issued pursuant to a registration statement dated and filed with the Securities and Exchange Commission on August 16, 2000. The complaints purported to allege violations of Sections 11, 12(a)(2) and 15 of the Securities Act of 1933 based on statements in or omissions from the registration statement concerning certain secured equity-linked loans by AES subsidiaries, the supposedly volatile nature of AES stock, as well as AES allegedly unhedged operations in the United Kingdom at that time, and the alleged effect of the New Electrical Trading Agreements on AES United Kingdom operations. On April 14, 2003, lead plaintiffs filed an amended and consolidated complaint, which added former IPALCO directors and officers John R. Hodowal, Ramon L. Humke and John R. Brehm as defendants and, in addition to the purported claims in the original complaints, purported to allege against the newly added defendants violations of Sections 10(b) and 14(a) of the Securities Exchange Act of 1934 and Rules 10b-5 and 14a-9 promulgated thereunder. The amended complaint also purported to add a claim based on alleged misstatements or omissions concerning an alleged breach by AES of alleged obligations AES owed to Williams Energy Services Co. (Williams) under an agreement between the two companies in connection with the California energy market. On September 26, 2003, defendants filed a motion to dismiss the amended and consolidated complaint. By Order dated November 17, 2004, the Court dismissed all of the claims asserted in the amended and consolidated complaint against all defendants except for the claim alleging that the registration statement and prospectus disseminated to the IPALCO stockholders for purposes of the share exchange transaction failed to disclose AES purported temporary default on its contract with Williams. On December 15, 2004, the AES defendants filed a motion for judgment on the pleadings to dismiss the remaining claims. On July 7, 2005, the district court granted defendants motion for judgment on the pleadings and entered an order dismissing all claims and thereby terminating this action in the district court. The time to file an appeal to the action has expired without the filing of an appeal.

In April 2002, IPALCO and certain former officers and directors of IPALCO were named as defendants in a purported class action lawsuit filed in the United States District Court for the Southern District of Indiana. On May 28, 2002, an amended complaint was filed in the lawsuit. The amended complaint asserts that IPALCO and former members of the pension committee for the Indianapolis Power & Light Company thrift plan breached their fiduciary duties to the plaintiffs under the Employees Retirement Income Security Act by investing assets of the thrift plan in the common stock of IPALCO prior to the acquisition of IPALCO by the Company. In December 2002, plaintiffs moved to certify this case as a class action. The Court granted the motion for class certification on September 30, 2003. On October 31, 2003, the parties filed cross-motions for summary judgment on liability. On August 11, 2005, the Court issued an Order denying the summary judgment motions, but striking one defense asserted by defendants. A trial addressing only the allegations of breach of fiduciary duty began on February 21, 2006 and concluded on February 28, 2006. Post trial briefs are due by April 6, 2006, and responses are due by April 20, 2006. A decision will follow sometime thereafter. If the Court rules against the IPALCO defendants, one or more trials on reliance, damages, and other issues will be conducted separately. IPALCO believes it has meritorious defenses to the claims asserted against it and intends to defend this lawsuit vigorously.

In November 2002, Stone & Webster, Inc. (S&W) filed a lawsuit against AES Wolf Hollow, L.P. (AESWH) and AES Frontier, L.P. (AESF, and, collectively with AESWH, sub-subsidiaries) in the District Court of Hood County, Texas. At the time of filing, AESWH and AESF were two indirect subsidiaries of the Company, but in December 2004, the Company finalized agreements to transfer the ownership of AESWH and AESF. S&W contracted with AESWH and AESF in March 2002 to perform the engineering, procurement and construction of the Wolf Hollow project, a gas-fired combined cycle power plant in Hood County, Texas. In its initial complaint, filed in November 2002, S&W requested a declaratory judgment that a fire that took place at the project on June 16, 2002 constituted a force majeure event, and that S&W was not required to pay rebates assessed for associated delays. As part of the initial complaint, S&W also sought to enjoin AESWH and AESF from drawing down on letters of credit provided by S&W. The Court refused to issue the injunction, and the sub-subsidiaries drew down on the letters of credit and withheld milestone payments from S&W. S&W has since amended its complaint five times and joined additional parties, including the Company and Parsons Energy & Chemicals Group, Inc. In addition to the claims already mentioned, the current claims by S&W include claims for breach of contract, breach of warranty, wrongful liquidated damages, foreclosure of lien, fraud and negligent misrepresentation. S&W appears to assert damages against the sub-subsidiaries and the Company in the amount of $114 million in recently filed expert reports and seeks exemplary damages. S&W filed a lien against the ownership interests of AESWH and AESF in the property, with each lien allegedly valued, after amendment on March 14, 2005, at approximately $87 million. In January 2004, the Company filed a counterclaim against S&W and its parent, the Shaw Group, Inc. (Shaw). AESWH and AESF filed answers and counterclaims against S&W, which since have been amended. The amount of AESWH and AESF s counterclaims are approximately $215 million, according to calculations of the sub-subsidiaries and of an expert retained in connection with the litigation, minus the Contract balance, not earned as of December 31, 2005, to the knowledge or the Company, in the amount of $45.8 million. In March 2004, S&W and Shaw each filed an answer to the counterclaims. The counterclaims and answers subsequently were amended. In March 2005, the Court rescheduled the trial date for October 24, 2005. In September 2005, the trial date was re-scheduled for June 2006. In November 2005, the Company filed a motion for summary judgment to dismiss the claims asserted against it by S&W. On February 21, 2006 the Court issued a letter ruling granting the Company s motion for summary judgment and directing the Company to submit a proposed order. On February 22, 2006 the Company submitted a proposed order, which has been objected to by S&W and Shaw. On March 15, 2006, S&W moved to reconsider the Court s decision granting the Company s summary judgment motion. A decision on the proposed order and the motion for reconsideration are pending; the Court has yet to enter a final order on the Company s summary judgment motion. The Company believes that the allegations in S&W s complaint are meritless, and that it has meritorious defenses to the claims asserted by S&W. The Company intends to defend the lawsuit and pursue its claims vigorously.

In March 2003, the office of the Federal Public Prosecutor for the State of Sao Paulo, Brazil (MPF) notified AES Eletropaulo that it had commenced an inquiry related to the BNDES financings provided to AES Elpa and AES Transgas and the rationing loan provided to AES Eletropaulo, changes in the control of AES Eletropaulo, sales of assets by AES Eletropaulo and the quality of service provided by AES Eletropaulo to its customers, and requested various documents from AES Eletropaulo relating to these matters. In October 2003 this inquiry was sent to the MPF for continuing investigation. Also in March 2003, the Commission for Public Works and Services of the Sao Paulo Congress requested AES Eletropaulo to appear at a hearing concerning the alleged default by AES Elpa and AES Transgas on the BNDES financings and the quality of service rendered by AES Eletropaulo. This hearing was postponed indefinitely. In addition, in April 2003, the office of the MPF notified AES Eletropaulo that it is conducting an inquiry into possible errors related to the collection by AES Eletropaulo of customers unpaid past-due debts and requesting the company to justify its procedures. In December 2003, ANEEL answered, as requested by the MPF, that the issue regarding the past-due debts are to be included in the analysis to the revision of the General Conditions for the Electric Energy Supply.

In May 2003, there were press reports of allegations that in April 1998 Light Serviços de Eletricidade S.A. (Light) colluded with Enron in connection with the auction of AES Eletropaulo. Enron and Light were among three potential bidders for AES Eletropaulo. At the time of the transaction in 1998, AES owned less than 15% of the stock of Light and shared representation in Light s management and Board with three other shareholders. In June 2003, the Secretariat of Economic Law for the Brazilian Department of Economic Protection and Defense (SDE) issued a notice of preliminary investigation seeking information from a number of entities, including AES Brasil Energia, with respect to certain allegations arising out of the privatization of AES Eletropaulo. On August 1, 2003, AES Elpa responded on behalf of AES-affiliated companies and denied knowledge of these allegations. The SDE began a follow-up administrative proceeding as reported in a notice published on October 31, 2003. In response to the Secretary of Economic Law s official letters requesting explanations on such accusation, AES Eletropaulo filed its defense on January 19, 2004. On April 7, 2005 AES Eletropaulo responded to a SDE request for additional information. On July 11, 2005, the SDE ruled that the case was dismissed due to the passing of the statute of limitations and was subsequently sent to the Superior Council of the SDE for final review of the decision.

AES Florestal, Ltd., (Florestal), a wooden utility pole manufacturer located in Triunfo, in the state of Rio Grande do Sul, Brazil, has been operated by Sul since October 1997 as part of the original privatization transaction by the Government of the State of Rio Grande do Sul, Brazil, that created Sul. From 1997 to the present, the chemical compound chromated copper arsenate was used by Florestal to chemically treat the poles under an operating license issued by the Brazilian government. Prior to 1997, another chemical, creosote, was used to treat the poles. After becoming the operator of Florestal, Sul discovered approximately 200 barrels of solid creosote waste on the Florestal property. In 2002, a civil inquiry (Civil Inquiry No. 02/02) was initiated and a criminal lawsuit was filed in the city of Triunfo s Judiciary both by the Public Prosecutors office of the city of Triunfo. The civil lawsuit was settled in 2003, and on June 27, 2005, the criminal lawsuit was dismissed. Florestal hired an independent environmental assessment company to perform an environmental audit of the operational cycle at Florestal. Florestal submitted an action plan that was accepted by the environmental authority under which it voluntarily offered to do containment work at the site. Companhia Estadual de Energia Elétrica (CEEE), which controlled Florestal prior to the privatization, has disputed the transfer of Florestal in the privatization, and has sought its return. A court decision recently determined that CEEE has rights of ownership in Florestal, and the company will be returned to CEEE. AES Sul will demand the return of that portion of the purchase price paid in the privatization for Florestal.

On January 27, 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., Dominican Power Partners, and AES Andres BV) and one distribution company (Empresa Distribuidora de Electricidad del Este, S.A.) in the Dominican Republic, violates certain cross-ownership restrictions contained in the General Electricity law of the Dominican Republic. On February 10, 2004, the Company filed in the First Instance Court of the National District of the Dominican Republic (Court) an action seeking injunctive relief based on several constitutional due process violations contained in the Formulation of Charges (Constitutional Injunction). On or about February 24, 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. On March 1, 2004, the Superintendence of Electricity appealed the Court s decision. On or about July 12, 2004, the Company divested any interest in Empresa Distribuidora de Electricidad del Este, S.A. The Superintendence of Electricity s appeal is pending. The Company believes it has meritorious defenses to the claims asserted against it and intends to defend this lawsuit vigorously.

In July 2004, the Corporación Dominicana de Empresas Eléctricas Estatales (CDEEE), which is the government entity that currently owns 50% of Empresa Generadora de Electricidad Itabo, S.A. (Itabo), filed two lawsuits against Itabo, an AES affiliate, and another lawsuit against Ede Este, a former indirect subsidiary of AES. The lawsuits against Itabo also name the former president of Itabo as a defendant. In one of the lawsuits against Itabo, CDEEE requested an accounting of all transactions between Itabo and related parties. On November 29, 2004, the First Room of the Court of First Instance of the National District dismissed the case. CDEEE appealed the dismissal to the Second Room of the Court of Appeal of the National District. A hearing was held on May 12, 2005, and Itabo requested that the Court of Appeal of the National District declare that it lacked jurisdiction to decide the matter, in light of the arbitration clause set forth in the contracts executed between Itabo and CDEEE during the Capitalization Process. The Court of Appeal of the National District denied Itabo s request and ordered that the claims be heard on the merits, but reserved judgment on Itabo s arguments that the matter should be resolved in an arbitration proceeding. On May 25, 2005, Itabo appealed before the Court of Appeals of Santo Domingo and requested a stay of the May 12, 2005 decision. On October 14, 2005 the Court of Appeals of Santo Domingo upheld Itabo s request of jurisdictional incompetence, accepting Itabo s argument that the International Chamber of Commerce (ICC) had exclusive jurisdiction over the matter. In the other Itabo lawsuit, CDEEE requested that the Second Room of the Court of Appeal of the National District order Itabo to deliver its accounting books and records for the period from September 1999 to July 2004 to CDEEE. At a hearing on March 30, 2005, Itabo argued that the Court of Appeal of the National District did not have jurisdiction to hear the case, and that the case should be decided in an arbitration proceeding. On October 6, 2005 the Court of Appeal of the National District upheld Itabo s petition of jurisdictional incompetence and declared that the lawsuit should be decided in an arbitral proceeding. CDEEE filed an appeal of the decision with the First Room of the Court of Appeal of the National District, which is pending. In the Ede Este lawsuit, CDEEE requests an accounting of all of Ede Este s commercial and financial operations with affiliate companies since August 5, 1999. This lawsuit was dismissed by the First Instance Tribunal of the National District for lack of jurisdiction. CDEEE then filed an identical lawsuit in the First Instance Tribunal of the Santo Domingo Province, which is pending. In a related proceeding, on May 26, 2005, Itabo filed a lawsuit in the United States District Court for the Southern District of New York, seeking to compel CDEEE to arbitrate its claims against Itabo. The petition was denied on July 18, 2005, and Itabo appealed that decision on September 6, 2005. The appeal is pending. In another related proceeding, on February 9, 2005, Itabo initiated arbitration against CDEEE and the Fondo Patrimonial para el Desarrollo (FONPER) in the Arbitral Court of the ICC seeking, among other relief, to enforce the arbitration/dispute resolution provisions in the contracts among the parties. FONPER submitted an answer and a counterclaim while CDEEE submitted only an answer. On March 28, 2006, Itabo and FONPER executed an agreement resolving all of their respective claims in the arbitration. The settlement agreement will be submitted to the ICC. The arbitration continues as between Itabo and CDEEE. Itabo believes it has meritorious defenses to the allegations asserted against it and will defend itself vigorously against those allegations.

On February 18, 2004, AES Gener S.A. (Gener SA), a subsidiary of the Company, filed a lawsuit against Coastal Itabo, Ltd. (Coastal), Gener SA s co-venturer in Itabo, a Dominican Republic power generation company, in the Federal District Court for the Southern District of New York. The lawsuit sought to enjoin the efforts initiated by Coastal to hire an alleged independent expert, purportedly pursuant to the Shareholders Agreement between the parties, to perform a valuation of Gener SA s aggregate interests in Itabo. Coastal asserted that Gener SA had committed a material breach under the parties Shareholders Agreement, and therefore, Gener SA was required if requested by Coastal to sell its aggregate interests in Itabo to Coastal at a price equal to 75% of the independent expert s valuation. Coastal claimed a breach occurred based on alleged violations by Gener SA of purported antitrust laws of the Dominican Republic and breaches of fiduciary duty. Gener SA disputed that any default had occurred. On March 11, 2004, upon motion by Gener SA, the court enjoined disclosure of the valuation performed by the expert and ordered the parties to arbitration. On March 11, 2004, Gener SA commenced arbitration proceedings seeking, among other things, a declaration that it had not breached the Shareholders Agreement. Coastal then filed a counterclaim alleging that Gener SA had breached the Shareholders Agreement. On January 4, 2006, Coastal filed a Withdrawal of Counterclaim with a Withdrawal of Notice of Defaults withdrawing with prejudice its allegations that Gener SA had violated the Shareholders Agreement. On January 25, 2006, the arbitration tribunal heard arguments on the form of the final award and whether to award fees and costs to Gener SA. The arbitration tribunal s decision on those matters is pending.

Pursuant to the pesification established by the Public Emergency Law and related decrees in Argentina, since the beginning of 2002, the Company s subsidiary TermoAndes has converted its obligations under its gas supply and gas transportation contracts into pesos. In accordance with the Argentine regulations, payments were made in Argentine pesos at a 1:1 exchange rate. Certain gas suppliers (Tecpetrol, Mobil and Compañía General de Combustibles S.A.), which represented 50% of the gas supply contract, have objected to the payment in pesos. On January 30, 2004, such gas suppliers filed for arbitration with the ICC requesting the re-dollarization of the gas price. TermoAndes replied on March 10, 2004 with a counter-lawsuit related to: (i) the default of suppliers regarding the most favored nation clause; (ii) the unilateral modification of the point of gas injection by the suppliers; (iii) the obligations to supply the contracted quantities; and (iv) the ability of TermoAndes to resell the gas not consumed. On January 26, 2006, the parties reached agreement resolving all reciprocal claims, including those submitted for arbitration. The settlement agreement was submitted to the arbitration court for it to issue a decision based on the agreed settlement. The arbitration court has yet to issue a decision.

On or about October 27, 2004, Raytheon Company (Raytheon) filed a lawsuit against AES Red Oak LLC (Red Oak) in the Supreme Court of the State of New York, County of New York. The complaint purports to allege claims for breach of contract, fraud, interference with contractual rights and equitable relief concerning alleged issues related to the construction and/or performance of the Red Oak project. The complaint seeks the return from Red Oak of approximately $30 million that was drawn by Red Oak under a letter of credit that was posted by Raytheon related to the construction and/or performance of the Red Oak project. Raytheon also seeks $110 million in purported additional expenses allegedly incurred by Raytheon in connection with the guaranty and construction agreements entered with Red Oak. In December 2004, Red Oak answered the complaint and filed counterclaims against Raytheon. In January 2005, Raytheon moved for dismissal of Red Oak s counterclaims. In March 2005, the motion to dismiss was withdrawn and a partial motion for summary judgment was filed by Raytheon seeking return of approximately $16 million of the letter of credit draw. Red Oak submitted its opposition to the partial motion for summary judgment in April 2005. Meanwhile, Raytheon re-filed its motion to dismiss the fraud allegations in the counterclaim. In late April 2005, Red Oak filed its response opposing the renewed motion to dismiss. In December 2005, the Court granted a dismissal of Red Oak s fraud claim. The Court also ordered the return of approximately $16 million of the letter of credit draw that had yet to be utilized for the performance/construction issues. At the Court s suggestion, the parties are negotiating whether to deposit the $16 million into a new letter of credit by Raytheon. The parties are conducting discovery. The discovery cut-off is December 15, 2006. Raytheon also filed a related action against Red Oak in the Superior Court of Middlesex County, New Jersey, on May 27, 2005, seeking to foreclose on a construction lien filed against property allegedly owned by Red Oak, in the amount of $31 million. Red Oak was served with the Complaint in September of 2005, and filed its answer, affirmative defenses, and counterclaim in October of 2005. Raytheon has stated that it wishes to stay the New Jersey action pending the outcome of the New York action. Red Oak has not decided whether it wishes to oppose the lien or consent to a stay. Red Oak believes it has meritorious defenses to the claims asserted against it and expects to defend itself vigorously in the lawsuits.

In 2004, the Hungarian environmental authority issued a notice of environmental penalty to Borsod, AES Hungarian generation facility, for approximately $733,000 for emissions violations. Borsod believes that the environmental authority s penalty calculation does not properly reflect Borsod s environmental investments, and has therefore appealed the calculation to the Supreme Court of Hungary. If Borsod s appeal is successful, the penalty will be reduced to approximately $175,000. A decision is expected in the second quarter of 2006. In addition, on October 24, 2005, Borsod paid an environmental penalty in local currency equivalent to approximately $191,000 for operations during 2004. Since January 1, 2005, Borsod has been operating with reduced emissions as required by regulation 14/2001, so either no penalty, or at least a reduced penalty, is expected for 2005 operations.

On January 26, 2005, the City of Redondo Beach (City), California, sent Williams Power Co., Inc., (Williams) and AES Redondo Beach, LLC (AES Redondo), an indirect subsidiary of the Company, a notice of assessment for allegedly overdue utility users tax (UUT) for the period of May 1998 through September 2004, taxing the natural gas used at AES Redondo s plant to generate electricity during that period. The original assessment included alleged amounts owing of $32.8 million for gas usage and $38.9 million in interest and penalties. The City lowered the total assessment to $56.7 million on July 13, 2005, based on an admitted calculation error. An administrative hearing before the Tax Administrator was held on July 18-21, 2005, to hear Williams and AES Redondo s respective objections to the assessment. On

September 23, 2005, the Tax Administrator issued a decision holding AES Redondo and Williams jointly and severally liable for approximately $56.7 million, over $20 million of which is interest and penalties (September 23 Decision). On October 7, 2005, AES Redondo and Williams filed an appeal of that decision with the City Manager of Redondo Beach. Under its Ordinance, the City of Redondo Beach was required to hold the appeal hearing within 45 days of the filing of the appeal. The City s hearing officer, however, has issued a tentative schedule stating that any hearing will be completed by April 21, 2006, and that the appeal determination will be issued by May 19, 2006. In addition, in July 2005, AES Redondo filed a lawsuit in Los Angeles Superior Court seeking a refund of UUT that was paid from February 2005 through final judgment of that case, and an order that the City cannot charge AES Redondo UUT going forward. At a February 6, 2006 status conference, the Los Angeles Superior Court stayed AES Redondo s July 2005 lawsuit until May 22, 2006, after ordering the City and AES Redondo to agree on dates by which the administrative appeal of the September 23 Decision should be finalized. On May 22, 2006, the Court will hold a status conference to determine whether the Court should proceed with AES Redondo s July 2005 lawsuit. Furthermore, on December 13, 2005, the Tax Administrator sent AES Redondo and Williams two itemized bills for allegedly overdue UUT on the gas used at the facility. The first bill was for $1,274,753.49 in UUT, interest, and penalties on the gas used at the facility from October 1, 2004, through February 1, 2005. The second bill was for $1,757,242.12 in UUT, interest, and penalties on the gas used at the facility from February 2, 2005, through September 30, 2005. Subsequently, on January 21, 2006, the Tax Administrator sent AES Redondo and Williams another itemized bill that assessed $269,592.37 in allegedly overdue UUT, interest, and penalties on gas used at the facility from October 1, 2005, through December 31, 2005. On December 30, 2005, AES Redondo filed objections with the Tax Administrator to the City s December 13, 2005, January 21, 2006, and any future UUT assessments. A hearing has not been scheduled on those objections, but the Tax Administrator has denied AES Redondo s objections to the December 13, 2005 UUT assessments based on the findings of his September 23 Decision, which, as noted above, is on appeal. If there is a hearing on the December 13, 2005, and January 21, 2006, UUT assessments, the Tax Administrator has indicated that he will only address the amount of those assessments, but not the merits of them. The Company believes that it has meritorious defenses to the allegations asserted against it and will defend itself vigorously against the allegations.

The Government of the Dominican Republic (Dominican Republic) and its attorneys have stated in press reports that the Dominican Republic intends to file lawsuits in United States and Dominican courts against The AES Corporation (the Company) asserting various claims purportedly relating to the alleged disposal of manufactured aggregate in the Dominican Republic. The manufactured aggregate allegedly was manufactured at a Puerto Rico facility owned by a subsidiary of the Company and located in Guayama, Puerto Rico. The Dominican Republic and its attorneys have stated that the Dominican Republic will seek $80 million in purported damages. The Company has not been served with the referenced lawsuit regarding the manufactured aggregate.

ITEM 4 *SUBMISSION OF MATTERS TO VOTE OF SECURITY HOLDERS*

No matters were submitted to a vote of security holders during the fourth quarter of 2005.

PART II

ITEM 5. *MARKET FOR REGISTRANT S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS*

Recent Sales of Unregistered Securities

None.

Market Information

Our common stock is currently traded on the New York Stock Exchange (NYSE) under the symbol AES. The following tables set forth the high and low sale prices for our common stock as reported by the NYSE for the periods indicated.

Price Range of Common Stock

2005	**High**	**Low**
First Quarter	$ 17.65	$ 12.84
Second Quarter	17.36	13.72
Third Quarter	16.67	14.67
Fourth Quarter	17.10	14.94

2004	**High**	**Low**
First Quarter	$ 10.71	$ 8.02
Second Quarter	10.15	7.69
Third Quarter	10.65	9.20
Fourth Quarter	13.67	10.15

Holders

As of February 28, 2006, there were approximately 7,650 record holders of our common stock, par value $0.01 per share.

Dividends

Under the terms of our Senior Secured Credit Facilities, which we entered into with a commercial bank syndicate, we are not allowed to pay cash dividends. 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. The terms of the indentures governing our outstanding Senior Subordinated Notes and Second Priority Senior Secured Notes also restrict our ability to pay dividends.

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 that our project subsidiaries are subject to.

See Item 12 (d) of this Form 10-K for information regarding Securities Authorized for Issuance under Equity Compensation Plans.

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data set forth in this item 6 has been restated to correct errors that were contained in our consolidated financial statements and other financial information included in our 2004 Annual Report on Form 10-K/A, filed with the U.S. Securities and Exchange Commission on January 19, 2006. The following selected financial data should be read in conjunction with our consolidated financial statements and the related notes to the consolidated financial statements.

Our 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 of this Form 10-K for further explanation of the effect of such activities. Please refer to Item 1A and Note 22 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.

	Years Ended December 31,				
	2005	2004 (Restated)(1)	2003 (Restated)(1)	2002	2001
	(in millions, except per share data)				
Statement of Operations Data:					
Revenues	$ 11,086	$ 9,463	$ 8,413	$ 7,377	$ 6,299
Income (loss) from continuing operations	632	264	294	(2,064)	323
Discontinued operations, net of tax		34	(787)	(1,561)	(130)
Cumulative effect of change in accounting principle, net of tax	(2)		41	(376)	
Net income (loss)	$ 630	$ 298	$ (452)	$ (4,001)	$ 193
Basic income (loss) earnings per share:					
Income (loss) from continuing operations	$ 0.96	$ 0.41	$ 0.49	$ (3.83)	$ 0.61
Discontinued operations		0.06	(1.32)	(2.89)	(0.25)
Cumulative effect of change in accounting principle			0.07	(0.70)	
Basic income (loss) earnings per share	$ 0.96	$ 0.47	$ (0.76)	$ (7.42)	$ 0.36
Diluted income (loss) earnings per share:					
Income (loss) from continuing operations	$ 0.95	$ 0.41	$ 0.49	$ (3.83)	$ 0.60
Discontinued operations		0.05	(1.32)	(2.89)	(0.24)
Cumulative effect of change in accounting principle			0.07	(0.70)	
Diluted income (loss) earnings per share	$ 0.95	$ 0.46	$ (0.76)	$ (7.42)	$ 0.36

	December 31,				
	2005	2004 (Restated)(1)	2003 (Restated)(1)	2002	2001
	(in millions)				
Balance Sheet Data:					
Total assets	$ 29,432	$ 28,923	$ 29,137	$ 34,550	$ 36,636
Non-recourse debt (long-term)	$ 11,226	$ 11,817	$ 10,930	$ 10,044	$ 10,787
Non-recourse debt (long-term) Discontinued operations	$	$	$ 56	$ 4,126	$ 4,037
Recourse debt (long-term)	$ 4,682	$ 5,010	$ 5,862	$ 6,755	$ 5,891
Stockholders equity (deficit)	$ 1,649	$ 956	$ (102)	$ (855)	$ 5,154

---

(1) See Note 1 to the Consolidated Financial Statements included in Item 8 of this Form 10-K for information related to restated Consolidated Financial Statements. A $12 million reduction to stockholders equity was recognized as of January 1, 2003 as the cumulative effect of the correction of errors for all periods preceding January 1, 2003. This correction was not material to the financial data presented herein as of and for the years ended December 31, 2002 and 2001.

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

The accompanying management s discussion and analysis of financial condition and results of operations set forth in this Item 7 is restated to reflect the correction of errors that were contained in our consolidated financial statements and other financial information for the year ended December 31, 2004 as discussed below and in Note 1 of the Consolidated Financial Statements. The following management s discussion and analysis of financial condition and results of operations should be read in conjunction with our restated consolidated financial statements and the related notes.

RESTATEMENT OF CONSOLIDATED FINANCIAL STATEMENTS

Subsequent to filing its restated annual report on Form 10-K/A with the Securities Exchange Commission on January 19, 2006, the Company discovered its previously issued restated consolidated financial statements included certain errors in accounting for derivative instruments and hedging activities, minority interest expense and income taxes. The errors in accounting for derivative instruments and hedging activities resulted in differences in previously issued consolidated interim financial statements for certain quarterly periods in 2004 sufficient to require restatement of prior period interim results. The errors in accounting for income taxes and minority interest expense required restatement of previously issued consolidated annual financial statements.

As a result of evaluating these adjustments, the Company reduced its stockholders equity by $12 million as of January 1, 2003 as the cumulative effect of the correction of errors for all periods proceeding January 1, 2003, and restated its consolidated statements of operations and cash flows for the years ended December 31, 2004 and 2003 and its consolidated balance sheet as of December 31, 2004.

The restatement adjustments resulted in an increase to previously reported net income of $6 million for the year ended December 31, 2004 and in a decrease to previously reported net income of $17 million for the year ended December 31, 2003. There was no impact on gross margin or net cash flow from operating activities of the Company for any years presented. Based upon management s review it has been determined that these errors were inadvertent and unintentional. The errors relate to the following areas:

A. Accounting for Derivative Instruments and Hedging Activities

The Company determined that it failed to perform adequate on-going effectiveness testing for three interest rate cash flow hedges and one foreign currency cash flow hedge during 2004 as required by SFAS No. 133. As a result, the Company should have discontinued hedge accounting and recognized changes in the fair value of the derivative instruments in earnings prospectively from the last valid effectiveness assessment until the earlier of either (1) the expiration of the derivative instrument or (2) the re-designation of the derivative instrument as a hedging activity.

The net impact related to the correction of these errors to previously reported net income resulted in a decrease of $4 million and an increase of $2 million for the years ending December 31, 2004 and 2003, respectively.

B. Income Tax and Minority Interest Adjustments

As a result of the Company s year end closing review process, the Company discovered certain other errors related to the recording of income tax liabilities and minority interest expense. The adjustments primarily include:

- An increase in income tax expense related to the recording of certain historical withholding tax liabilities at one of our El Salvador subsidiaries;

- An increase in minority interest expense related to a correction of the allocation of income tax expense to minority shareholders. This allocation pertained to certain deferred tax adjustments recorded in the original restatement at one of our Brazilian generating companies. In addition, minority interest expense was also corrected at this subsidiary as a result of identifying differences arising from a more comprehensive reconciliation of prior year statutory financial records to U.S. GAAP financial statements.

- A reduction of 2004 income tax expense related to adjustments derived from 2004 income tax returns filed in 2005.

The net impact related to the correction of these errors to previously reported net income resulted in an increase of $10 million and a decrease of $19 million for the years ending December 31, 2004 and 2003, respectively. In addition, the Company restated stockholders equity as of January 1, 2003 by $12 million as a correction for these errors in all periods preceding January 1, 2003.

C. Other Balance Sheet Reclassifications

Certain other balance sheet reclassifications were recorded at December 31, 2004 including a $45 million reclassification which reduced Accounts Receivables and increased Other Current Assets (regulatory assets).

EXECUTIVE SUMMARY AND OVERVIEW

The following discussion should be read in conjunction with our restated consolidated financial statements and notes to the consolidated financial statements included in Item 8 of this Form 10-K, and other information included in this report.

Who Are We?

AES is a global power company managed to meet the growing demand for electricity in ways that benefit all of our stakeholders. AES is a holding company that through its subsidiaries and affiliates owns and operates a portfolio of electricity generation and distribution businesses in 25 countries. We seek to capture the benefits of our global expertise and economies of scale in our operations. Predictable and growing cash flow, an efficient capital structure, operating and portfolio risk management, and world-class operating performance are the focus of our management efforts.

What Businesses Are We In?

We operate in two principal businesses. The first is the generation of power for sale to utilities and other wholesale customers. The second is the operation of electric utilities which distribute power to retail, commercial, industrial and governmental customers. Our financial results are reported as three business segments, two for the generation business and one for the utility business.

Our businesses may be significantly affected by a number of risks, uncertainties and other factors. Important factors that could affect financial results are discussed under Section 1A, Risk Factors.

What Are Our Reporting Segments?

We report our generation business under two reporting segments, contract generation and competitive supply. These segments together consist of approximately 36.4 gigawatts of generating capacity from 107 power plants in 20 countries.

Our contract generation businesses principally sell electricity to utilities or other wholesale customers under power purchase agreements (PPA) of generally five years or longer and for 75% or more of their capacity. These PPAs are designed to provide a predictable recovery of the costs of building and operating our plants as well as generating a return on our investment. Fuel supply cost risk is often limited contractually either through contract price escalation provisions or through tolling arrangements where we convert the customer s fuel into electricity. Through these contractual agreements, the businesses generally reduce commodity and electricity price volatility and thereby increase the predictability of their gross margin, net income and cash flow.

Our competitive supply businesses sell electricity to wholesale customers through competitive markets and, as a result, the cash flows and earnings of such businesses are more sensitive to fluctuations in the market price of electricity, as well as natural gas, coal and other fuels. However, for our U.S. competitive supply business which includes a fleet of low-cost coal fired plants in New York, we typically hedge the majority of our fuel exposure on a rolling two year basis.

Our regulated utilities consist of 14 distribution companies in seven countries with approximately 11 million end-user customers. Three of these utilities, in the U.S., Venezuela and Cameroon, are integrated utilities providing both power generation and distribution. The remaining utilities, located in Brazil, El Salvador, Argentina, and Ukraine, are solely transmission and distribution businesses. Only one of our regulated utilities, Indianapolis Power and Light (IPL), is located in the U.S.

The largest part of our utility business portfolio operates in emerging markets, where electricity demand is expected to grow at a higher rate than in more developed countries. However, we are exposed to foreign currency, political, payment, and economic risks and significant electricity theft-related losses within developing countries. The challenge within all of these businesses is to provide dependable and quality service to a diverse customer base and achieve appropriate returns on investment through tariff increases, cost management and prudent capital investment.

In 2005, we realigned our management reporting structure into four regions: North America; Latin America; Europe, Middle East and Africa (EMEA); and Asia, each led by a regional president who reports directly to the Chief Executive Officer (CEO). This realignment allowed us to place senior leaders and resources closer to the businesses to further improve operating performance and integrate operations and development on a more localized level. This structure will help us leverage regional market trends to enhance our competitiveness and identify and capitalize on key business development opportunities. The organizational changes are expected to streamline some corporate functions to more effectively support AES businesses around the globe.

The Company also maintains a corporate Business Development group which manages large scale transactions such as mergers and acquisitions, and portfolio management, as well as targeted strategic initiatives. In addition to our primary business of operating a global power portfolio, we are engaged in exploring and promoting a set of related activities that include alternative energy businesses such as wind generation, the supply of liquefied natural gas to certain targeted North American markets, the production of greenhouse gas reduction activities and new energy technologies. At present, these initiatives represent growth opportunities for us but currently account for a de minimus amount of revenue and earnings.

What Did We Focus On In 2005?

In 2005, we focused on global operational excellence, deleveraging and credit improvement, and our growth strategies. Our operational focus included (a) safety, (b) plant and distribution system operational excellence and (c) customer service. Our deleveraging and credit improvement focus included (a) paying down $2.7 billion in debt, including $254 million at the parent company, (b) extending maturities of subsidiary debt, (c) improving parent liquidity, and (d) gaining improved parent and subsidiary credit quality and ratings. It was also a year to rebuild our growth development pipeline under a new organization structure implemented midyear. We completed the restatement of our prior year Form 10-K and are continuing to develop and implement action plans to address the material weaknesses within our financial reporting processes.

How Did We Do?

Revenue We achieved record revenues in 2005 of $11.1 billion, an increase of 17% from $9.5 billion last year. Favorable foreign currency trends and higher prices led the increase.

Gross margin Gross margin increased 14% to $3.2 billion, driven by the higher revenues.

Net cash from operating activities Our cash flow increased 38% to $2.2 billion, driven by higher net earnings (adjusted for non-cash items), an increase in other assets net of other liabilities, and a decrease in working capital.

Earnings per share Diluted earnings per share from continuing operations increased 132% to $0.95 in 2005 from $0.41 in 2004. Higher revenue and gross margin, together with favorable foreign currency transaction effects led the improvement.

What Was The Restatement About?

At the end of 2004, the Company identified a material weakness related to its accounting for deferred income taxes and embarked upon a global process to document the deferred income tax calculations and to perform more detailed reconciliations at its foreign subsidiaries. In July 2005 the Company determined that errors found during that process required a restatement, which was completed in January 2006. The restatement required that the Company re-file its 2004 Form 10-K and its previously issued Form 10-Q for the first quarter of 2005. The most significant adjustments involved areas of accounting that required a high degree of interpretation and/or judgment involving transactions which occurred during and prior to 2002. Management concluded that all errors were both inadvertent and unintentional. The income tax restatement errors identified primarily relate to:

- the calculation of deferred income taxes related to certain purchase accounting adjustments for acquisitions,
- the correct application of foreign currency translation of certain deferred income tax balances, and
- the correction of other income tax accounts related to a review and reconciliation of prior year income tax returns.

As a result of extended review procedures, certain other adjustments related to the classification of cash versus short-term investments, consolidation, acquisition and translation accounting and revenue deferrals related to a Brazilian energy efficiency program, were identified and corrected.

In addition, subsequent to the filing of the Company s restated financial statements as described above, the Company identified certain other errors which led us to restate our 2003 and 2004 year end numbers and the quarterly periods for 2004. These adjustments related largely to the correction of income tax expense and minority interest expense upon additional year end review of certain calculations performed during the earlier restatement process. Additionally, we identified certain derivative adjustments related to the proper documentation and treatment of a cash flow foreign currency hedge and cash flow interest rate hedges at certain of our foreign businesses.

How Are We Addressing Our Material Weaknesses?

As of December 31, 2005, the Company reported material weaknesses related to the following areas: accounting for income taxes; an aggregation of control deficiencies at our Cameroonian subsidiary; a lack of U.S. GAAP expertise and review in our Brazilian businesses; the treatment of intercompany loans denominated in other than the functional currency; and, accounting for derivatives.

Management, the Audit Committee and our Board of Directors are committed to the remediation of the material weaknesses and the continued improvement of the Company s overall system of internal control over financial reporting. Over the last several years, in recognition of the decentralized and complex nature of our organization, management, the Audit committee and the Board of Directors have taken steps to improve the quality of the people, processes and systems within the Company s income tax, accounting, financial reporting, internal control, compliance and internal audit functions. This included creating several new Corporate leadership positions as well as adding staffing to these functions.

In response to the material weaknesses reported as of December 31, 2005, management has developed remediation plans for each of the weaknesses and is undergoing continued efforts to strengthen the existing finance organization and systems across the Company. These efforts include the reorganization of the Company-wide accounting and tax functions to align the local business finance functions with teams at the Corporate office. In addition, the Company is continuing to further expand the number of accounting and tax personnel at the Corporate office who will provide technical support and oversight of our global financial processes, as well as adding additional finance resources to our subsidiaries. This accelerated hiring effort began in February 2006, and, once completed, is expected to result in approximately 50 additional personnel within the Corporate finance organization as well as additional personnel at our subsidiaries, particularly those subsidiaries where material weaknesses were found. While the recruiting and reorganization effort is underway, the Company will continue to use third parties to provide assistance in the performance of relevant accounting and tax procedures, as well as provide assistance in the development and execution of the remediation plans.

In its effort to develop a world-class finance organization, the Company is preparing a finance leadership development program, in partnership with an international leader in management education, that is expected to begin offering courses for our finance professionals in June 2006. In addition, various levels of training programs on specific aspects of U.S. GAAP are being developed for distribution to our subsidiaries during 2006. In March 2006, the Company completed its first in-depth training related to Accounting for Income Taxes, with participation from approximately 100 AES professionals from our Corporate office, domestic, and international subsidiaries.

While the Company continues to refine and execute its remediation efforts, it will utilize additional resources to assist in the program management aspect of each material weakness remediation plan and has committed to provide status reports to our external auditors and our Audit Committee of the Board of Directors on a monthly basis throughout 2006.

What Key Growth Projects are Underway?

Our largest growth project under construction remains a 1,200 MW gas-fired power plant in Cartagena, Spain. This project is scheduled for completion in 2006, and will provide power under long-term contract to Gaz de France which will sell into the Spanish merchant power market. Other important growth projects under construction include 120 MW diesel-fired peaking facility to serve the largest power market in Chile, and a 120 MW wind farm project in Texas. Both of these projects are scheduled to be on-line in 2006 as well. In addition, a multi-pollution control project is under construction at our Greenidge coal-fired plant in New York, which will extend the useful life of the project and allow for more economical power dispatch and the generation of additional air emission allowances, both leading to increased revenues.We also secured a 15 year PPA and matching fuel supply agreement, together with construction and long-term financing for a new 670 MW (gross) lignite-fired power plant near Galabovo, Bulgaria. This project is in final engineering and permitting stages and is expected to enter construction in the spring of 2006, with start-up planned in two phases in 2009 and 2010. We have also secured a 10 year PPA for a new 150 MW hydro-electric power plant in Panama. AES has begun the engineering and geo-technical work and plans to begin construction in 2007. The plant is scheduled to be operational by 2010.

How Are We Positioning For Growth?

AES s strategy for growing its business involves utilizing a local management structure operating in local markets. AES believes this is the best method for identifying and capitalizing on growth opportunities. These opportunities generally happen in a variety of ways: (i) through platform expansions, which are investment opportunities in existing businesses or existing country markets; (ii) greenfield development, which typically means development and construction of a new facility; and (iii) privatizations, which involves the transfer of government-owned generation and distribution systems in the private sector. These opportunities are pursued by the Company s regional organizations. These efforts are supplemented by targeted mergers and acquisitions, which can be on an individual basis or involve more complex portfolios. These efforts are led by the Company s corporate Business Development group, acting in conjunction with the appropriate regional organization.

Our active development pipeline of potential growth investments includes opportunities in 38 countries. We have assessed country financial and operating risks in prioritizing those countries in which we would like to make investments, and look to develop a balanced geographic portfolio over time with increased presence in Eastern Europe and Asia in particular. We continue to devote significant resources at both the corporate and business level in support of these opportunities and are funding development related costs which could lead to significant new investments in 2006 and in future years. We signed a memorandum of understanding in 2005 to develop a 1,000 MW coal fired power plant in Vietnam in partnership with a Vietnamese coal producer. These agreements may or may not lead to a firm project, but provide the basis for improving the potential for a successful project, especially if the agreement is entered into on an exclusive basis.

We continue to develop wind generation opportunities, a market we entered early in 2005. We quickly became a significant player in the U.S., with responsibility for the operation of 500 MW of wind facilities and 1,000 MW of wind projects in development. We also continue to develop stand-alone LNG regasification facilities, and have started development of two new projects on the U.S. east cost during the year. Our proposed Bahamas LNG regasification terminal and 95-mile natural gas pipeline from the terminal to serve south Florida, awaits final Bahamian government approval.

The global power market is extremely large and offers multiple opportunities. In the European Union (EU), the market rules require a liberalized competitive wholesale power market as a condition for EU entry. However, there are a number of considerations that may limit the number of available near term opportunities in other markets. First, in the United States and, to a lesser extent, Western Europe there is limited need for new capacity, reducing the number of available greenfield opportunities in the most stable markets. Many states in the United States have slowed or reversed their trends towards liberalization, thereby reducing the number of available opportunities. Internationally, some planned privatization programs have been deferred for specific local reasons. In some of the markets outside of the United States that are liberalizing the rules, those rules are being designed such that the risks are too great to justify the level of returns currently available. Hence we have decided to either not participate in those markets or to only do so in a limited manner and wait for a more balanced set of rules or regulations to emerge.

An adjunct part of our growth strategies is portfolio management. High valuations placed on generation assets in particular, which is noted below as a challenge to our growth strategies, is also an opportunity to monetize investments or a portion of one or more of our businesses where we see the marketplace placing a significantly higher value on assets than what our own valuation shows. We would likely use proceeds from such portfolio management transaction to fund new growth investments.

The Company expects to fund these investments from our cash flows from operations and/or the proceeds from our issuance of debt, common stock, other securities and asset sales. We see sufficient value creating growth investment opportunities that may exceed available cash and cash flow from operations in future periods.

What Are Our Key Challenges?

There are several challenges we face in achieving our plans for 2006 and beyond.

Global Competition

We have seen increased global competition in our markets. In the United States and Europe multiple new financial sponsors are aggressively acquiring assets. Internationally, a number of new, regionally focused and aggressive competitors have emerged. This increased competition has led to an increase in the prices for assets in both secondary asset sales and privatizations. Prices for materials and engineering and construction services are increasing, and there is a limited supply of certain key equipment components, especially in the wind generation marketplace, which may limit our ability to secure growth opportunities or achieve acceptable returns.

Foreign Currency Risk

A significant majority of our business portfolio is located outside of the U.S. and therefore usually subject to both currency translation and transaction risk. Our financial position and results of operations have been affected in the past by significant fluctuations in the value of the Argentine peso, Brazilian real and Venezuelan bolivar relative to the U.S. dollar. We hedge certain transaction exposures principally related to debt, and have restructured debt into local currency denomination to minimize risk when possible. Although these actions may have mitigated negative impacts in certain cases, movements within currencies are difficult to predict and continue to have a significant impact on our financial results.

Political Environment

Several of our businesses operate in politically unstable environments. The impact of governmental change and uncertainty impacts foreign currency volatility, our ability to maintain or attract needed financing, as well as our ability to effectively recover costs through routine tariff or regulatory reset proceedings.

Regulatory Risk

Due to the regulated nature of the utilities business, we are subject to regulatory risk related to changes in tariff agreements, and existing laws and provisions. Changes in regulation may impact our future operations, cash flows and financial condition.

Long-term Contracts

Several of our power generation plants operate on a long term contract basis with one or a limited number of contracts related to both the fuel supply and power demand. The remaining periods for these long-term contracts range from 1 to 26 years. The ability of our customers and suppliers to perform under these contracts and our ability to negotiate new contracts upon expiration may have a significant impact on our results of operations in the future.

Performance Improvement

Although we continue to place significant effort on performance improvement initiatives, it remains difficult to measure the financial impact of such initiatives in our financial results, and the reported impact has not been significant in comparison to other important business drivers such as price, volume, and foreign currency movements. In addition, benefits from global sourcing include avoided costs, reduction in actual versus originally estimated capital project costs, and projected savings on assumed spend volume which may or may not actually be achieved. These benefits will not be fully reflected in our consolidated financial position, results of operations and cash flows.

Looking Ahead What Is Our Key Focus For 2006?

Our focus in 2006 will be in several key areas, starting with safety, by building on two years of improvement in both lower lost workday cases and in reporting of accidents and near misses. Operational excellence will also continue to drive for improvements in both the generation and utility businesses. In addition, management is committed to the remediation of our material weaknesses in internal control over financial reporting as well as the continued improvement of the Company s overall system of internal controls. The Company also will continue to strengthen its training and development programs for AES people at all levels.

We will continue to pursue growth opportunities, including platform expansion, greenfield projects, privatization and mergers and acquisitions, as well as our strategic initiatives in alternative energy businesses such as wind generation, LNG, and climate change. As we see an increase in projects under construction, we look to further strengthen our ability to manage and execute multiple construction projects. We want to ensure all the appropriate policies, work procedures, and accountability is in place to execute transactions with proper financial controls and tax and accounting determinations.

To take advantage of these opportunities we intend to leverage our existing strengths and capitalize on favorable market conditions to deliver higher earnings and cash flow and improved credit quality. The catalysts to further growth, consistent with appropriate risk/reward profiles, include both external and internal factors such as:

- continued electricity demand growth in key markets;
- attraction of private and public capital for emerging markets;
- government policies that encourage the development of new areas of opportunity, including renewable energy; and
- experience with related areas that can lead to business opportunities such as LNG regasification, fossil fuel sourcing, non-power markets, and air emission allowance markets.

CRITICAL ACCOUNTING ESTIMATES

The consolidated financial statements of AES are prepared in conformity with generally accepted accounting principles in the United States of America, 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 revenues and expenses during the periods presented. AES s significant accounting policies are described in Note 1 to the Consolidated Financial Statements included in Item 8 of this Form 10-K. Critical accounting estimates are described in this section. 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 if changes in the estimate that would have a material impact on the Company s financial condition or results of operations are reasonably likely to occur from period to period. Management believes that the accounting estimates employed are appropriate and the resulting balances are reasonable; however, actual results could differ from the original estimates, requiring adjustments to these balances in future periods.

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 collectability and aging of accounts receivable. There is an increased level of exposure related to the Company s regulated utilities receivables in certain non U.S. locations which are due from local municipalities and other governmental agencies. These customers are often large and normally pay within extended timeframes. The amount of historical experience is limited in some cases due to the recent nature of AES acquisitions subsequent to privatization. In addition, local political and economic factors often play a part in a municipality s current ability or willingness to pay. The Company monitors these situations closely and continues to refine its reserving policy based on both historical experience and current knowledge of the related political/economic environments.

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. 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 is reasonable, it is possible that the ultimate outcome of current or future examinations may exceed current reserves in amounts that could be material. A range of these amounts cannot be reasonably estimated at December 31, 2005, as they are primarily unasserted claims.

On October 22, 2004, the American Jobs Creation Act (the AJCA) was signed into law. The AJCA includes a deduction of 85% of certain foreign earnings that are repatriated, as defined in the AJCA. The Company conducted an evaluation of the effects of the repatriation provision in accordance with recently issued Treasury Department guidance. As a result, the Company elected not to apply this provision to qualifying earnings repatriations in 2005.

Long-Lived Assets

In accordance with SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets, we periodically review the carrying value of our long-lived assets held and used, other than goodwill and intangible assets with indefinite lives, and assets to be disposed of when circumstances indicate that the carrying amount of such assets may not be recoverable or the assets meet the held for sale criteria under SFAS No. 144. These events or circumstances may include the relative pricing of wholesale electricity by region and the anticipated demand and cost of fuel. If the carrying amount is not recoverable, an impairment charge is recorded 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 rate recovery was probable. For non-regulated assets, an impairment charge would be recorded as a charge against earnings.

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, that is, other than a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for measurement, if available. In the absence of quoted market prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow projections or other indicators of fair value such as bids received, comparable sales or independent appraisals.

In connection with the periodic evaluation of long-lived assets in accordance with the requirements of SFAS No. 144, 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 16 to the Consolidated Financial Statements included in Item 8 of this Form 10-K, we made our best estimate of fair value using valuation methods based on the most current information at that time. We have been in the process of divesting certain assets and their sales values can vary from the recorded fair value as described in Note 19 to the Consolidated Financial Statements included in Item 8 of this Form 10-K. 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.

Goodwill

We review the carrying value of our goodwill annually during the fourth quarter. We also review the carrying value of our goodwill periodically when events and circumstances warrant such a review. This review is performed using estimates of fair value and includes discounted future cash flows. If the carrying value of goodwill is considered impaired, an impairment charge is recorded.

Pension and Postretirement Obligations

Certain of our foreign and domestic subsidiaries maintain defined benefit pension plans which we refer to as the pension plans, or the plans, covering substantially all of their respective employees. Pension benefits are generally based on years of credited service, age of the participant and average earnings. Of the twenty one defined benefit pension plans existing at December 31, 2005, two exist at domestic subsidiaries and the remainder exists at foreign subsidiaries. The measurement of our pension obligations, costs and liabilities is dependent on a variety of assumptions used by our actuaries. 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. The plan trustee conducts an independent valuation of the fair value of pension plan assets.

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
- Mortality rates

The effects of actual results differing from our 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 assumption is shown below. Although not an estimate, we ve also included sensitivity around the actual return on pension assets. Note that these sensitivities may be asymmetric, and are specific to the base conditions at year-end 2005. 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, 2005 funded status is affected by December 31, 2005 assumptions. Pension expense for 2005 is affected by December 31, 2004 assumptions. The impact on our funded status, equity and U.S. pension expense from a one percentage point change in these assumptions is shown below (in millions):

Increase of 1% in the discount rate	$(16)
Decrease of 1% in the discount rate	$23
Increase of 1% in the long-term rate of return on plan assets	$(19)
Decrease of 1% in the long-term rate of return on plan assets	$19

Regulatory Assets and Liabilities

The Company accounts for certain of its regulated operations under the provisions of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. As a result, AES records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-

regulated entities. Regulatory assets generally represent incurred costs that have been deferred because such 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. 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, the asset write-offs would be required to be recognized in operating income.

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.

Under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, we recognize all derivatives as either assets or liabilities in the balance sheet and measure those instruments at fair value. Changes in fair value of derivatives are recognized in earnings unless specific hedge criteria are met. Income and expense related to derivative instruments are recorded in the same category as generated by the underlying asset or liability.

SFAS No. 133 enables 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 as, 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. Changes in the fair value of a derivative that is highly effective as, 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 SFAS No. 133. If we deem that the derivative is not highly effective as a hedge, hedge accounting will be discontinued prospectively.

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 volatilities, market liquidity, future commodity prices, interest rates, credit ratings, and exchange rates.

AES generally uses quoted exchange prices to the extent they are available to determine the fair value of derivatives. In the absence of actively quoted market prices, we seek indicative price information from external sources, including broker quotes and industry publications. If pricing information from external sources is not available, AES will estimate prices, when possible, based on available historical and near-term future price information as well as utilizing statistical methods. When external valuation models are not available, the company utilizes internal models for valuation. For individual contracts, the use of different valuation models or assumptions could have a material effect on the calculated fair value.

For cash flow hedges of forecasted transactions, AES must estimate the future cash flows represented by the forecasted transactions, as well as evaluate the probability of 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 for the reclassification of gains or losses on cash flow hedges from accumulated other comprehensive loss (AOCI) into earnings.

NEW ACCOUNTING PRONOUNCEMENTS

Consolidation of Variable Interest Entities

In January 2003, the Financial Accounting Standards Board (FASB) issued Financial Interpretation No. 46, Consolidation of Variable Interest Entities An Interpretation of ARB No. 51 (FIN 46 or Interpretation). FIN 46 is an interpretation of Accounting Research Bulletin 51 Consolidated Financial Statements, and addresses consolidation by business enterprises of variable interest entities (VIE). The primary objective of the Interpretation is to provide guidance on the identification of and financial reporting for, entities over which control is achieved through means other than voting rights; such entities are known as VIEs. The Interpretation requires an enterprise to consolidate a VIE if that enterprise has a variable interest that will absorb a majority of the entity s expected losses if they occur, receive a majority of the entity s expected residual returns if they occur or both. An enterprise shall consider the rights and obligations conveyed by its variable interests in making this determination. On December 24, 2003, the FASB issued Interpretation No. 46 (Revised 2003) Consolidation of Variable Interest Entities (FIN 46(R) or Revised Interpretation), which partially deferred the effective date of FIN 46 for certain entities and makes other changes to FIN 46, including a more complete definition of variable interest and an exemption for many entities defined as businesses. The Company applied FIN 46 in its financial statements relating to its interest in variable interest entities or potential variable interest entities as of December 31, 2003, and applied FIN 46(R) as of March 31, 2004. The application of FIN 46(R) did not have an impact on the Company s condensed consolidated financial statements for any quarter through December 31, 2004.

In March 2005, the FASB issued Staff Position (FSP) No. FIN 46(R)-5, Implicit Variable Interests under FASB Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities. This FSP clarifies that when applying the variable interest consolidation model, a reporting enterprise should consider whether it holds an implicit variable interest in a variable interest entity (VIE) or potential VIE. FSP No. FIN 46(R)-5 became effective as of April 1, 2005. Upon the adoption of FSP No. FIN 46(R)-5, the Company did not identify any potential or implicit VIEs.

Share-Based Payment

In December 2004, the Financial Accounting Standards Board (FASB) issued a revised Statement of Financial Accounting Standard (SFAS) No. 123, Share-Based Payment. SFAS 123R eliminates the intrinsic value method as an alternative method of accounting for stock-based awards under Accounting Principles Board (APB) No. 25 by requiring that all share-based payments to employees, including grants of stock options for all outstanding years, be recognized in the financial statements based on their fair values. It also revises the fair-value based method of accounting for share-based payment liabilities, forfeitures and modifications of stock-based awards and clarifies the guidance under SFAS No. 123 related to measurement of fair value, classifying an award as equity or as a liability and attributing compensation to reporting periods. In addition, SFAS No. 123R amends SFAS No. 95, Statement of Cash Flows, to require that excess tax benefits be reported as a financing cash flow rather than as an operating cash flow.

Effective January 1, 2003, the Company adopted the fair value recognition provision of SFAS No. 123, as amended by SFAS No. 148, prospectively to all employee awards granted, modified or settled after January 1, 2003. We adopted SFAS No. 123R and related guidance on January 1, 2006, using the modified prospective transition method. Under this transition method, compensation cost will be recognized (a) based on the requirements of SFAS No. 123R for all share-based awards granted subsequent to January 1, 2006 and (b) based on the original provisions of SFAS No. 123 for all awards granted prior to January 1, 2006, but not vested as of this date. Results for prior periods will not be restated. Management is currently evaluating the effect of the adoption of SFAS No. 123R under the modified prospective application transition method, but does not expect the adoption to have a material effect on the Company s financial condition, results of operations or cash flows.

Conditional Asset Retirement Obligations

In March 2005, the FASB issued FASB Interpretation (FIN) No. 47 Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143, which clarifies the term conditional asset retirement obligation as used in SFAS No. 143 Accounting for Asset Retirement Obligations. Specifically, FIN 47 provides that an asset retirement obligation is conditional when the timing and/or method of settling the obligation is conditioned on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing and/or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. This interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective for fiscal years ending after December 15, 2005.

The Company s asset retirement obligations covered by FIN 47 primarily include conditional obligations to demolish assets or return assets in good working condition at the end of the contractual or concession term, and for the removal of equipment containing asbestos and other contaminants. As of December 31, 2005, the Company recorded additional asset retirement obligations in the amount of $18 million as a result of the implementation of FIN 47. The cumulative effect of the initial application of this Interpretation was recognized as a change in accounting principle in the amount of $2 million, net of income tax benefit of $1 million.

The pro forma net income (loss) and earnings (loss) per share resulting from the adoption of FIN 47 for the years ended December 31, 2005, 2004 and 2003, is not materially different from the actual amounts reported in the accompanying consolidated statement of operations for those periods. Had FIN 47 been applied during all periods presented, the asset retirement obligations at December 31, 2003 and December 31, 2004 would have been approximately $14 million and $15 million, respectively.

RESULTS OF OPERATIONS

	For The Years Ended December 31,				
	2005	2004	2003	$ change 2005 vs. 2004	$ change 2004 vs. 2003
	(in millions, except per share data)				
Gross Margin:					
Regulated utilities	$ 1,237	$ 1,116	$ 976	$ 121	$ 140
Contract generation	1,603	1,428	1,262	175	166
Competitive supply	338	238	221	100	17
Total gross margin	3,178	2,782	2,459	396	323
General and administrative expenses(1)	(221)	(182)	(157)	(39)	(25)
Interest expense	(1,896)	(1,932)	(1,984)	36	52
Interest income	391	282	280	109	2
Other income, net	19	12	65	7	(53)
Loss on sale of investments, asset and goodwill impairment expense		(45)	(212)	45	167
Foreign currency transaction (losses) gains on net monetary position	(89)	(165)	99	76	(264)
Equity in earnings (loss) of affiliates	76	70	94	6	(24)
Income tax expense	(465)	(359)	(211)	(106)	(148)
Minority interest (expense) income	(361)	(199)	(139)	(162)	(60)
Income (loss) from continuing operations	632	264	294	368	(30)
Income (loss) from operations of discontinued businesses		34	(787)	(34)	821
Cumulative effect of accounting change	(2)		41	(2)	(41)
Net income (loss)	$ 630	$ 298	$ (452)	$ 332	$ 750
PER SHARE DATA:					
Basic income (loss) per share from continuing operations	$ 0.96	$ 0.41	$ 0.49	$ 0.55	$ (0.08)
Diluted income (loss) per share from continuing operations	$ 0.95	$ 0.41	$ 0.49	$ 0.54	$ (0.08)

(1) General and administrative expenses are corporate and business development expenses.

Overview

Revenue

	For the Years Ended December 31, 2005		2004		2003	
	Revenue	% of Total Revenue	Revenue	% of Total Revenue	Revenue	% of Total Revenue
Regulated Utilities	$ 5,737	52%	$ 4,897	52%	$ 4,425	53%
Contract Generation	4,137	37%	3,546	37%	3,108	37%
Competitive Supply	1,212	11%	1,020	11%	880	10%
Non-Regulated	5,349	48%	4,566	48%	3,988	47%
Total	$ 11,086	100%	$ 9,463	100%	$ 8,413	100%

Revenues increased approximately $1.6 billion, or 17%, to $11.1 billion in 2005 from $9.5 billion in 2004, primarily in the Regulated Utilities and Contract Generation segments. Regulated utilities revenues increased $840 million, or 17%, mostly due to favorable exchange rates at our Brazilian utilities while contract generation revenues increased $591 million, or 17%, due to increased contract pricing and favorable foreign exchange rates at our businesses in Brazil, Chile and Mexico. Excluding the estimated impacts of foreign currency translation effect, revenues would have increased approximately 10% from 2004 to 2005. Excluding businesses that commenced commercial operations in 2005 or 2004, the revenue increase would remain at 17% in 2005.

Revenues increased approximately $1.1 billion, or 12%, to $9.5 billion in 2004 from $8.4 billion in 2003, primarily in the Regulated Utilities and Contract Generation segments. Regulated utilities revenues increased $472 million, or 11%, mostly due to increased tariffs at our Latin American utilities while contract generation revenues increased $438 million, or 14%, mainly due to higher contract prices and new projects coming on line in Qatar, Oman and the Dominican Republic. Excluding the estimated impacts of foreign currency translation effect, revenues would have increased approximately 11% from 2003 to 2004. Excluding businesses that commenced commercial operations in 2004 or 2003, revenues increased 11% to $9.3 billion in 2004.

Gross Margin

	For the Years Ended December 31, 2005		2004		2003	
	Gross Margin	% of Total Gross Margin	Gross Margin	% of Total Gross Margin	Gross Margin	% of Total Gross Margin
Regulated Utilities	$ 1,237	39%	$ 1,116	40%	$ 976	40%
Contract Generation	1,603	50%	1,428	51%	1,262	51%
Competitive Supply	338	11%	238	9%	221	9%
Non-Regulated	1,941	61%	1,666	60%	1,483	60%
Total	$ 3,178	100%	$ 2,782	100%	$ 2,459	100%
Gross Margin as a % of Revenue	28.7%		29.4%		29.2%	

Gross margin increased $396 million, or 14%, to $3.2 billion in 2005 from $2.8 billion in 2004, with gross margin improvements in all segments during 2005 compared to 2004. Contract generation gross margin increased $175 million, or 12%, due to higher contract pricing while regulated utilities gross margin increased $121 million, or 11%, as a result of higher overall revenues and lower fixed expenses. Competitive supply gross margin increased $100 million, or 42%, due to higher prices and the sale of environmental allowances. Excluding businesses that commenced commercial operations in 2005 or 2004, the gross margin increase in 2005 would remain at 14%. Gross margin as a percentage of revenues decreased to 28.7% in 2005 from 29.4% in 2004 due to higher fuel costs throughout most of our businesses, increased receivable reserves in our Brazilian utilities and higher unrecovered purchased electricity prices in our regulated utilities.

Gross margin increased $323 million, or 13%, to $2.8 billion in 2004 from $2.5 billion in 2003, as gross margin for all segments improved in 2004 compared to 2003. Contract generation gross margin increased $166 million, or 13%, due to higher contract pricing and new projects coming on line while regulated utilities gross margin increased $140 million, or 14%, as a result of increased tariffs. Competitive supply gross margin increased $17 million, or 8%, due to higher prices slightly offset by higher fuel costs. Excluding businesses that commenced commercial operations in 2004 or 2003, gross margin increased 10% to $2.7 billion in 2004. Gross margin as a percentage of revenues increased to 29.4% in 2004 from 29.2% in 2003.

Segment Analysis

Regulated Utilities Revenue

	For the Years Ended December 31,					
	2005		**2004**		**2003**	
	Revenue	**% of Total Revenue**	**Revenue**	**% of Total Revenue**	**Revenue**	**% of Total Revenue**
North America	$ 951	9%	$ 884	9%	$ 832	10%
Latin America	4,276	38%	3,550	38%	3,219	38%
EMEA	510	5%	463	5%	374	5%
Total	$ 5,737	52%	$ 4,897	52%	$ 4,425	53%

Regulated utilities revenues increased $840 million, or 17%, to $5.7 billion in 2005 from $4.9 billion in 2004, primarily due to higher revenues in our Latin America utilities, which experienced an increase in revenues of $726 million, or 20%, in 2005. Excluding the estimated impacts of foreign currency translation, regulated utilities revenues would have increased 5% from 2004 to 2005. This increase in Latin America utilities revenues was due to favorable exchange rates at AES Eletropaulo and Sul in Brazil, only partially offset by the negative impacts of foreign currency remeasurement at EDC in Venezuela. The Brazilian real appreciated 12% in 2005 while the Venezuelan bolivar devalued almost 11% for the same period. Recognition of a retroactive tariff increase, as well as an increase in the average customer tariff due to a rate increase at AES Eletropaulo in Brazil in 2005, also contributed to the year over year revenue increase in Latin America utilities revenues.

Regulated utilities revenues increased $472 million, or 11%, to $4.9 billion in 2004 from $4.4 billion in 2003, primarily due to higher revenues in our Latin America utilities, which experienced an increase in revenues of $331 million, or 10%, in 2004. Excluding the estimated impacts of foreign currency translation, regulated utilities revenues would have increased 10% from 2003 to 2004. This increase in Latin America utilities revenues was due to increased tariffs and favorable exchange rates at AES Eletropaulo and Sul in Brazil that were partially offset by lower sales volume. The average customer tariff at AES Eletropaulo increased in 2004 due to both a rate increase and an increase in residential consumption, although overall consumption decreased by 1%. Revenues at our Venezuelan subsidiary, EDC, also increased due to higher tariffs that were offset substantially by unfavorable exchange rates and reduced sales volumes.

Regulated Utilities Gross Margin

	For the Years Ended December 31, 2005		2004		2003	
	Gross Margin	% of Total Gross Margin	Gross Margin	% of Total Gross Margin	Gross Margin	% of Total Gross Margin
North America	$ 305	10%	$ 304	11%	$ 282	11%
Latin America	816	25%	754	27%	653	27%
EMEA	116	4%	58	2%	41	2%
Total	$ 1,237	39%	$ 1,116	40%	$ 976	40%
Regulated Utilities Gross Margin as a % of Regulated Utilities Revenue	21.6%		22.8%		22.1%	

Regulated utilities gross margin increased $121 million, or 11%, to $1.2 billion in 2005 from $1.1 billion in 2004, primarily due to higher gross margins in our Latin America and EMEA utilities. Gross margins in our Latin America utilities increased $62 million, or 8%, primarily as a result of higher overall revenues and favorable foreign currency translation impacts at AES Eletropaulo and Sul in Brazil offset by the recording of $192 million of gross bad debts reserve in the second quarter of 2005 related to the collectability of certain municipal receivables at our utilities in Brazil. Gross margins in our EMEA utilities increased $58 million, or 100%, as AES SONEL in Cameroon also showed positive results primarily due to higher revenues, better demand and lower fixed expenses. Gross margin for all regulated utilities as a percent of revenue decreased to 21.6% in 2005 compared to 22.8% in 2004 due to higher purchased electricity costs in all regions and the recording of the gross bad debts reserve mentioned earlier at our utilities in Brazil.

Regulated utilities gross margin increased $140 million, or 14%, to $1.1 billion in 2004 from $1.0 billion in 2003, primarily due to higher gross margins in our Latin America utilities, which experienced an increase in gross margin of $101 million, or 15%, in 2004. The increase in Latin America utilities gross margin was due to the increased tariffs and the favorable effect of exchange rates on revenues at AES Eletropaulo in Brazil partially offset by increased costs related to purchased electricity and bad debt provisions. Gross margin decreased at EDC in Venezuela due to the unfavorable effect of exchange rates and lower demand coupled with higher fixed costs in 2004 compared to 2003. Gross margin for regulated utilities as a percent of revenue increased slightly to 22.8% in 2004 compared to 22.1% in 2003 primarily due to increased tariffs in Latin America.

Contract Generation Revenue

	For the Years Ended December 31, 2005		2004		2003	
	Revenue	% of Total Revenue	Revenue	% of Total Revenue	Revenue	% of Total Revenue
North America	$ 1,281	11%	$ 1,258	13%	$ 1,221	15%
Latin America	1,755	16%	1,286	14%	1,070	13%
EMEA	956	9%	882	9%	699	8%
Asia	145	1%	120	1%	118	1%
Total	$ 4,137	37%	$ 3,546	37%	$ 3,108	37%

Contract generation revenues increased $591 million, or 17%, to $4.1 billion in 2005 from $3.5 billion in 2004 primarily due to increases at our Latin America and EMEA businesses, while North America and Asia showed slight improvements. Excluding the estimated impacts of foreign currency translation, revenues would have increased approximately 15% from 2004 to 2005. The increase in Latin America is primarily due to higher contract prices at Tiete (a group of hydro-electric plants providing electricity primarily to AES Eletropaulo) and Uruguaiana in Brazil, Gener in Chile and Los Mina in the Dominican Republic. In addition, the Latin America region was impacted by favorable foreign currency translation in Brazil and Chile. Andres in the Dominican Republic experienced increased volume in addition to higher prices. The increase in EMEA revenues is primarily due to higher contract prices at Tisza in Hungary and a full year of operations at Ras Laffan in Qatar. The increase in revenues in Asia is due to higher contract prices and availability at Kelanitissa in Sri Lanka. The increase in North America revenues is primarily due to higher contract prices and favorable foreign currency impacts at Merida in Mexico and higher prices at our business in Puerto Rico, along with the acquisition of the SeaWest wind business in the first quarter of 2005. These increases are partially offset by a decrease in contract price at Shady Point in Oklahoma and outages at Thames in Connecticut.

Contract generation revenues increased $438 million, or 14%, to $3.5 billion in 2004 from $3.1 billion in 2003 primarily due to increases at our Latin America and EMEA businesses. Excluding the estimated impacts of foreign currency translation, revenues would have increased approximately 12% from 2003 to 2004. The increase in revenues in Latin America is primarily due to increased contract pricing at Tiete in Brazil and Gener in Chile, along with a full year s operating results from Andres in the Dominican Republic. Additionally, the Latin America region was impacted by favorable foreign currency translation at Tiete and Gener. The increase in revenues in EMEA is primarily due to increased contract pricing at Kilroot in Northern Ireland and the completion of the Ras Laffan s power and water desalination plant in Qatar, as well as the reporting of a full year s operating results from Barka in Oman which came on line in 2003. These increases were slightly offset by lower volumes at Tisza in Hungary as a result of outages to perform plant upgrades in 2004. Additionally, the EMEA region was impacted favorably by foreign currency translation at Kilroot and Tisza. Slight increases in North America revenue is due to increased contract pricing at Merida in Mexico. Asia revenues remained fairly constant in 2003 and 2004.

Contract Generation Gross Margin

	For the Years Ended December 31,					
	2005		**2004**		**2003**	
	Gross Margin	**% of Total Gross Margin**	**Gross Margin**	**% of Total Gross Margin**	**Gross Margin**	**% of Total Gross Margin**
North America	$ 448	14%	$ 511	18%	$ 509	20%
Latin America	705	22%	512	18%	416	17%
EMEA	417	13%	380	14%	308	13%
Asia	33	1%	25	1%	29	1%
Total	$ 1,603	50%	$ 1,428	51%	$ 1,262	51%
Contract Generation Gross Margin as a % of Contract Generation Revenue	38.7%		40.3%		40.6%	

Contract generation gross margin increased $175 million, or 12%, to $1.6 billion in 2005 from $1.4 billion in 2004, with higher gross margin contributions from our Latin America businesses offset by lower gross margin contributions from our North American businesses. Gross margin in our Latin America generation businesses increased $193 million, or 38%, due to higher overall revenues at Tiete in Brazil and Gener in Chile and higher revenues and lower purchased electricity at Los Mina in the Dominican Republic. These increases were partially offset by unfavorable foreign currency translation and fixed costs at Tiete and higher fuel and variable costs at Gener. The North America gross margin decrease is primarily due to the decrease in the contract pricing at Shady Point in Oklahoma, outages incurred at Thames in

Connecticut and lower dispatch at Southland in California. The contract generation gross margin as a percentage of revenue decreased to 38.7% in 2005 from 40.3% in 2004.

Contract generation gross margin increased $166 million, or 13%, to $1.4 billion in 2004 from $1.3 billion in 2003 with higher gross margin contributions from our Latin America and EMEA businesses. Gross margin in the Latin America businesses increased primarily due to increased contract pricing escalations at Tietê and Uruguaiana in Brazil slightly offset by higher fuel costs at Gener in Chile. The inclusion of a full year s operating results for Andres in the Dominican Republic also contributed to the gross margin increase. The EMEA gross margin increase is primarily due to pricing escalations at Kilroot in Northern Ireland which were partially offset by higher fuel costs in that same business. Gross margin in EMEA was positively impacted further by the completion of Ras Laffan s power and water desalination plant in Qatar, as well as the reporting of a full year s operating results for Barka in Oman which came on line in 2003. Gross margin in North America and Asia remained fairly constant during the period. The contract generation gross margin as a percentage of revenues slightly decreased to 40.3% in 2004 from 40.6% in 2003.

Competitive Supply Revenue

	For the Years Ended December 31,					
	2005		**2004**		**2003**	
	Revenue	**% of Total Revenue**	**Revenue**	**% of Total Revenue**	**Revenue**	**% of Total Revenue**
North America	$ 544	5%	$ 447	5%	$ 459	5%
Latin America	389	4%	300	4%	186	2%
EMEA	121	1%	136	1%	132	2%
Asia	158	1%	137	1%	103	1%
Total	$ 1,212	11%	$ 1,020	11%	$ 880	10%

Competitive supply revenues increased $192 million, or 19%, to $1.2 billion in 2005 from $1.0 billion in 2004 primarily due to increases at our North America and Latin America businesses. Excluding the estimated impacts of foreign currency translation, revenues would have increased approximately 18% from 2004 to 2005. Asia showed slight increases in revenues which were almost entirely offset by declines from our businesses in EMEA. The increase in North America revenues is primarily due to higher prices and approximately $45 million in sales of emission allowances at our business in New York and higher prices obtained by Deepwater in Texas. The increase in Latin America revenues is due to higher prices and volume increases at Alicura and Parana in Argentina and higher prices at our business in Panama. Revenues from our Asia businesses showed slight increases due to a mix of higher prices and increased volume at Ekibastuz, Altai and Maikuben, all located in Kazakhstan. Decreases in revenues from our EMEA businesses are due primarily to the sale of Ottana in Italy during 2005 partially offset by higher prices at Borsod in Hungary.

Competitive supply revenues increased $140 million, or 16%, to $1.0 billion in 2004 from $880 million in 2003 primarily due increases at our Latin America and EMEA businesses. Excluding the estimated impacts of foreign currency translation, revenues would have increased approximately 13% from 2003 to 2004. Asia also showed increases which were partially offset by declines at our North America businesses. The increase in Latin America is primarily due to higher prices and significantly higher than expected dispatch at CTSN in Argentina as a result of increased demand caused by gas shortages in Argentina and increased revenues from the completion of Esti, a greenfield hydroelectric project in Panama, along with the expansion of another hydroelectric project at Bayano in Panama. Additionally, higher competitive market prices for electricity sold at Parana in Argentina also contributed to the overall Latin America increase. The increase in Asia is primarily due to higher competitive prices at Ekibastuz in Kazakhstan and positive foreign currency impacts at Ekibastuz and Altai in Kazakhstan. The increase in revenues in

EMEA is mainly due to positive foreign currency impacts at Ottana in Italy and Borsod in Hungary. These increases were more than offset by declines in North America caused by lower revenues from our plants in New York.

Competitive Supply Gross Margin

	For the Years Ended December 31,	
	2005	**2004**