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

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the Fiscal Year Ended December 31, 2009

-OR-

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

COMMISSION FILE NUMBER 1-12291

The AES Corporation

(Exact name of registrant as specified in its charter)

Delaware	**54 1163725**
(State or other jurisdiction of 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 ¨

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

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

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

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

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

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

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

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

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

DOCUMENTS INCORPORATED BY REFERENCE

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

Table of Contents

THE AES CORPORATION

FISCAL YEAR 2009 FORM 10-K

TABLE OF CONTENTS

PART I	1
ITEM 1. BUSINESS	3
Overview	3
Our Organization and Segments	6
Customers	19
Employees	19
Executive Officers	19
How to Contact AES and Sources of Other Information	20
Regulatory Matters	21
ITEM 1A. RISK FACTORS	58
ITEM 2. PROPERTIES	79
ITEM 3. LEGAL PROCEEDINGS	80
ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS	89
PART II	90
ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES	90
Purchases of Equity Securities by the Issuer and Affiliated Purchasers	90
Market Information	90
Holders	91
Dividends	91
ITEM 6. SELECTED FINANCIAL DATA	92
ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS	94
Overview of Our Business	94
Performance Highlights	98
Non-GAAP Measure	100
Consolidated Results of Operations	108
Critical Accounting Estimates	122
New Accounting Pronouncements	126
Capital Resources and Liquidity	128
Off-Balance Sheet Arrangements	138
ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK	141
Value at Risk	143
ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA	145
ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE	251
ITEM 9A. CONTROLS AND PROCEDURES	251
ITEM 9B. OTHER INFORMATION	254
PART III	254
ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE	254
ITEM 11. EXECUTIVE COMPENSATION	254
ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS	254
ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE	255
ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES	255
PART IV	256
ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES	256
SIGNATURES	262

Table of Contents

PART I

In this Annual Report the terms AES , the Company , us , or we refer to The AES Corporation and all of its subsidiaries and affiliates, collectivel The term The AES Corporation refers only to the parent, publicly-held holding company, The AES Corporation, excluding its subsidiaries and affiliates.

FORWARD-LOOKING INFORMATION

In this filing we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. Such statements are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Although we believe that these forward-looking statements and the underlying assumptions are reasonable, we cannot assure you that they will prove to be correct.

Forward-looking statements involve a number of risks and uncertainties, and there are factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements. Some of those factors (in addition to others described elsewhere in this report and in subsequent securities filings) include:

- the economic climate, particularly the state of the economy in the areas in which we operate, including the fact that the global economy has recently been in decline and faces considerable uncertainty for the foreseeable future which further increases many of the risks discussed in this Form 10-K;
- our ability to achieve expected rate increases in our Utility businesses;
- our ability to manage our operation and maintenance costs;
- the performance and reliability of our generating plants, including our ability to reduce unscheduled down-times;
- changes in the price of electricity at which our Generation businesses sell into the wholesale market and our Utility businesses purchase to distribute to their customers, and our ability to hedge our exposure to such market price risk;
- changes in the prices and availability of coal, gas and other fuels and our ability to hedge our exposure to such market price risk, and our ability to meet credit support requirements for fuel and power supply contracts;
- changes in and access to the financial markets, particularly those affecting the availability and cost of capital in order to refinance existing debt and finance capital expenditures, acquisitions, investments and other corporate purposes;
- changes in our or any of our subsidiaries corporate credit ratings or the ratings of our or any of our subsidiaries debt securities or preferred stock, and changes in the rating agencies ratings criteria;
- changes in inflation, interest rates and foreign currency exchange rates;
- our ability to purchase and sell assets at attractive prices and on other attractive terms;

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

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

changes in laws, rules and regulations affecting our business, including, but not limited to, deregulation of wholesale power markets and its effects on competition, the ability to recover net utility assets and other potential stranded costs by our utilities, the establishment of a regional transmission organization (RTO) that includes our utility service territory, the application of market power criteria by the Federal Energy Regulatory Commission (FERC), changes in law

Table of Contents

resulting from new federal energy legislation, including the effects of the repeal of Public Utility Holding Company Act of 1935 (PUHCA 1935), and changes in political or regulatory oversight or incentives affecting our wind business, our solar joint venture, our other renewables projects and our initiatives in greenhouse gas (GHG) reductions and energy storage including tax incentives;

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

variations in weather, especially mild winters and cooler summers in the areas in which we operate, low levels of wind or sunlight for our wind and solar businesses, and the occurrence of difficult hydrological conditions for our hydro-power plants, as well as, hurricanes and other storms and disasters;

our ability to meet our expectations in the development, construction, operation and performance of our wind businesses, which rely, in part, on actual wind conditions and wind turbine performance being in line with our expectations;

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

our ability to keep up with advances in technology;

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

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

the effects of litigation and government investigations;

decreases in the value of pension plan assets, increases in pension plan expenses and our ability to fund defined benefit pension and other post-retirement plans at our subsidiaries;

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

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

our ability to attract and retain talented directors, management and other personnel, including, but not limited to, financial personnel in our foreign businesses that have extensive knowledge of accounting principles generally accepted in the United States (GAAP).

These factors in addition to others described elsewhere in this Form 10-K and in subsequent securities filings, should not be construed as a comprehensive listing of factors that could cause results to vary from our forward looking information.

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

Table of Contents

ITEM 1. BUSINESS

Overview

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

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

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

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

Key Lines of Business

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

Table of Contents

Revenue

($ in billions)

Gross Margin

($ in billions)

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

Generation

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

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

Table of Contents

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

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

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

Utilities

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

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

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

Table of Contents

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

Renewables and Other Initiatives

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

Risks

We routinely encounter and address risks, some of which may cause our future results to be different, sometimes materially different, than we presently anticipate. The categories of risk we have identified in Item 1A. Risk Factors of this Form 10-K include the following:

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

The categories of risk identified above are discussed and explained in greater detail in Item 1A. Risk Factors of this Form 10-K. These risk factors should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, and the Consolidated Financial Statements and related notes included elsewhere in this report.

Our Organization and Segments

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

Virginia.

Table of Contents

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

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

Corporate and Other The Company s Europe Utilities, Africa Utilities, Africa Generation and AES Wind Generation businesses as well as the Company s solar, climate solutions and energy storage initiatives are reported within Corporate and Other because they do not require separate disclosure under segment reporting accounting guidance. See Item 7. Management s Discussion and Analysis of Financial Condition for further discussion of the Company s segment structure used for financial reporting purposes.

Latin America

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

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

Table of Contents

The graph below shows the breakdown between our Latin America Generation and Utilities segments as a percentage of total Latin America revenue and gross margin for the years ended December 31, 2009, 2008, and 2007. See Note 15 Segment and Geographic Information in the Consolidated Financial Statements in Item 8 of this Form 10-K for information on revenue from external customers, Adjusted Gross Margin (a non-GAAP measure) and total assets by segment.

Revenue

($ in billions)

Gross Margin

($ in billions)

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

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

Generation

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

Table of Contents

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

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

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

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

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

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

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

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

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

Generation under construction

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

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

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

9

Table of Contents

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

Distribution

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

North America

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

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

The graph below shows the breakdown between our North America Generation and Utilities segments as a percentage of total North America revenue and gross margin for the years ended December 31, 2009, 2008, and 2007. See Note 15 Segment and Geographic Information in the Consolidated Financial Statements in Item 8 of this Form 10-K for information on revenue from external customers, Adjusted Gross Margin (a non-GAAP measure) and total assets by segment.

Revenue

($ in billions)

Gross Margin

($ in billions)

Table of Contents

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

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

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

Generation

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

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

Table of Contents

IPL s generation facilities

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

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

Distribution

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

Europe

The following table provides highlights of our Europe operations:

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

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

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

Table of Contents

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

Generation

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

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

Generation under construction

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

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

Table of Contents

Asia

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

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

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

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

Generation

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

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

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

14

Table of Contents

Corporate and Other

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

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

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

Distribution

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

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

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

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

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

Generation

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

Table of Contents

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

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

Sonel s generation facilities

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

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

Sonel s distribution facility

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

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

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

Generation

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

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

Table of Contents

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

AES Wind Generation projects under construction

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

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

Other. AES Solar and certain other unconsolidated businesses are accounted for using the equity method of accounting. Therefore, their operating results are included in Net Equity in Earnings of Affiliates on the face of the consolidated statements of operations, not in revenue and gross margin. AES Solar was formed in March 2008 to develop, own and operate solar installations. Since its launch, AES Solar has commenced commercial operations of 32 MW of solar projects in Spain, has 57 MW under construction in Italy, Greece and France, and has development potential in Bulgaria, India and the U.S.

Corporate and Other also includes general and administrative expenses related to corporate staff functions and initiatives, executive management, finance, legal, human resources and information systems which are not allocable to our business segments and the effects of eliminating transactions, such as self insurance charges, between the operating segments and corporate. See Note 15 Segment and Geographic Information in the Consolidated Financial Statements in Item 8 of this Form 10-K for information on revenue from external customers, Adjusted Gross Margin (a non-GAAP measure) and total assets by segment.

Table of Contents

Financial Data by Country

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

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

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

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

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

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

Table of Contents

Customers

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

Employees

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

Executive Officers

The following individuals are our executive officers:

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

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

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

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

Table of Contents

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

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

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

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

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

How to Contact AES and Sources of Other Information

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

Table of Contents

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

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

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

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

Regulatory Matters

Overview

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

Regulation of our Generation Businesses

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

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

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

Table of Contents

Regulation of our Distribution Businesses

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

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

Latin America & Africa

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

Cameroon. The law governing the Cameroonian electricity sector was passed in December 1998. The regulator is the Electricity Sector Regulatory Agency (ARSEL) and its role is regulating and ensuring the

Table of Contents

proper functioning of the electricity sector, supervising the process of granting concessions, licenses and authorizations to operators, monitoring the application of the electricity regulation by the operators of the sector, approving and/or publicizing the regulated tariffs in the sector and safeguarding the interests of electricity operators and consumers. ARSEL has the legal status of a Public Administrative Establishment and is placed under the dual technical supervisory authority of the Ministries charged with electricity and finance.

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

The wholesale electricity market in the Dominican Republic commenced operations in June 2000. This market includes a spot market and contract market. All participants in the Dominican electric system with

Table of Contents

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

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

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

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

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

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

29

Table of Contents

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

Table of Contents

North America

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

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

United States. The U.S. wholesale electricity market consists of multiple distinct regional markets that are subject to both federal regulation, as implemented by the FERC, and regional regulation as defined by rules designed and implemented by the Independent System Operator (ISO). These rules for the most part govern such items as the determination of the market mechanism for setting the system marginal price for energy and the establishment of guidelines and incentives for the addition of new capacity. The current regulatory framework in the U.S. is the result of a series of regulatory actions that have taken place over the past two decades, as well as numerous policies adopted by both the federal government and the individual states that encourage competition in wholesale and retail electricity markets.

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

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

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

Several of our generation businesses in the U.S. currently operate as Qualifying Facilities (QFs) as defined under PURPA. These businesses entered into long-term contracts with electric utilities that had a mandatory obligation at that time, as specified under PURPA, to purchase power from QFs at the utility s avoided cost (i.e., the likely costs for both energy and facilities that would have been incurred by the purchasing utility if that utility had to provide its own generating capacity). EPAct 2005 later amended PURPA to eliminate the mandatory purchase obligation in certain markets, but did so only on a prospective basis. Cogeneration facilities and small power production facilities that meet certain criteria can be QFs. To be a QF, a cogeneration facility must produce electricity and useful thermal energy for an industrial or commercial process or heating or cooling applications in certain proportions to the facility s total energy output, and must meet certain efficiency standards. To be a QF, a small power production facility must generally use a renewable resource as its energy input and meet certain size criteria.

Table of Contents

Our non-QF generation businesses in the U.S. currently operate as Exempt Wholesale Generators (EWG s) as defined under EPAct 1992. These businesses were historically exempt from the Public Utility Holding Company Act of 1935 and are also exempt from the Public Utility Holding Company Act of 2005 (PUHCA 2005), and subject to FERC approval, have the right to sell power at market-based rates, either directly to the wholesale market or to a third-party offtaker such as a power marketer or utility/industrial customer. Under the Federal Power Act (FPA) and FERC s regulations, approval from FERC to sell wholesale power at market-based rates is generally dependent upon a showing to FERC that the seller lacks market power in generation and transmission, that the seller and its affiliates cannot erect other barriers to market entry and there is no opportunity for abusive transactions involving regulated affiliates of the seller. To prevent market manipulation, FERC requires sellers with market-based rate authority to file certain reports, including a triennial updated market power analysis.

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

Table of Contents

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

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

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

Europe, Middle East & Asia

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

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

The main transmission company, Red Eléctrica de España (REE) owns 99% of the 400 kV grid and 98% of the 220 kV network. The law has been changed to ensure that REE will become the sole transmission company in Spain. REE also operates as system operator (TSO) and is responsible for technical management

Table of Contents

of the system and for monitoring transmission. Under the country s energy infrastructure plan, REE plans to invest in strengthening the mainland grid, connecting new plants and improving interconnection throughout the country. In due course, AES Cartagena entered into an agreement with REE for the construction of the interconnection facilities. The use of such facilities is the subject of another standard regulated contract stating the specific terms and conditions of access.

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

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

A comprehensive review of the distribution tariff methodology for the calculation including the rate of return on initial investment, operational expenses treatment, and definition and valuation of the rate base was expected to take place at the end of 2008. However, in late 2008, UNERC introduced minimal and short-term changes into the tariff methodology to be valid for 2009 and delayed a comprehensive review until 2010. Such short-term changes were implemented in 2009 and include (a) setting rates of return on initial investment at the level of 15% after tax for 2009, (b) wages and salaries treatment remaining as per the mechanism introduced in 2007, (c) operational expenses subject to indexation by inflation and (d) other operational expenses subject to

Table of Contents

adjustment based on actual expenses given reasonable substantiation. In late 2009, the comprehensive review was further delayed until 2011. For 2010, major elements of the 2009 tariff methodology were kept unchanged, including the 15% rate of return on investments. The delay is due to UNERC s intention to develop a new methodology applicable to all distribution and supply companies. In 2011, the comprehensive tariff methodology review is expected to take place addressing the issues of: (1) introduction of regulatory incentives to increase quality of service, (2) rate of return on investment, (3) rate base revaluation, and (4) operational expense allowance treatment.

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

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

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

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

Despite the new market mechanisms, Kilroot has continued to operate under its existing PPA which is able to subsist within the single wholesale market, although operating dispatch instructions are now a function of the new market inputs and system constraints and no longer the exclusive decision of NIE. While the PPAs are in place, Kilroot (a coal-fired plant), is neutral with respect to the cost of fuel as this is passed through to its PPA counterparty as an element of the payments made to Kilroot in respect of its availability. Although no PPAs were able to subsist, the NIAUR sought to invoke the introduction of the single electricity market (SEM) as a rationale for the early termination of the long-term PPAs between Kilroot and NIE Energy Limited. Kilroot challenged by way of judicial review proceedings the determination of NIAUR that the introduction of the SEM constituted requisite arrangements to allow such early termination. The hearing took place in May 2008 and found in favor of the NIAUR. On November 25, 2009, the NIAUR published a Consultation Paper on Relevant Considerations in Relation to the Possible Cancellation of Generating Unit Agreements in Northern Ireland

Table of Contents

which is relevant to various long-term PPAs in Northern Ireland including those at Kilroot. This consultation closed on January 27, 2010 and the paper states that it has been published by the NIAUR in order to set out and seek views on its initial thoughts on the type of issues and factors the NIAUR believes will or should inform the decision as to whether or not it should exercise its early cancellation power at the earliest opportunity. Although this power would grant the ability to the NIAUR to terminate the long-term PPAs from 2010 provided certain procedural steps and conditions are complied with, the current expectation is that due to the value of the CO_2 allowances (that passes through to the consumer while Kilroot is under contract), the likely earliest date that cancellation would be invoked is after 2012 (when free allowances are due to cease). If the PPAs were to be cancelled post-2012, Kilroot would then become a merchant plant and would operate under the gross mandatory pool operated in the SEM. The effect of this on the Kilroot business would then depend largely on the relative costs of coal and gas. Kilroot would continue to receive capacity payments under the SEM (although at a lower rate than the availability payments under the PPAs). If the price of coal was high relative to that of gas, this could have a material adverse impact for the Kilroot business. Conversely, if the price of coal was relatively low to that of gas, Kilroot could find this to be financially advantageous compared to the position under the existing PPAs.

Environmental and Land Use Regulations

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

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

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

Table of Contents

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

International

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

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

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

Table of Contents

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

20% increase in energy efficiency; and

Minimum compulsory 10% target for renewable energy by 2020.

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

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

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

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

Table of Contents

United States Federal Legislation and Regulation

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

- A planned target to reduce by 2020 GHG emissions by 17% from 2005 levels and to reduce GHG emissions by 83% from 2005 levels by 2050.

- A requirement that certain GHG emitting companies, including most power generators, surrender on an annual basis one ton of CO_2 equivalent allowances or GHG offset credits for each ton of annual CO_2 equivalent emissions. Such companies would be required to meet allowance surrender requirements via the allocations of free allowances if available from the U.S. Environmental Protection Agency (EPA) or purchases in the open market at auctions if free allowances are not allocated, or otherwise.

- A mechanism under which the EPA would initially issue a capped and steadily declining number of tradable free emissions allowances to certain sections of affected industries, including certain generators and utilities in the electricity sector, with such free distribution of allowances to the electricity sector phasing out over a five year period from 2026 through 2030.

- A provision permitting up to two billion tons of GHG offset credits in the aggregate, if available, to be purchased annually by all emitters to satisfy the requirements above.

- A provision precluding the EPA from regulating GHG emissions under the existing provisions of the Clean Air Act (CAA).

- A temporary prohibition on the implementation of similar State or regional GHG cap and trade programs, with a six-year moratorium (2012 to 2017) on the implementation or enforcement of similar GHG emission caps.

- The establishment of a combined energy efficiency and renewable electricity standard (RES) that would require retail electric utilities to receive 6% of their power from renewable sources by 2012, with such requirement increasing to 20% by 2020. In certain circumstances, a portion of this requirement for renewable energy could be satisfied through measures intended to increase energy efficiency.

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

United States State Legislation and Regulation

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

Table of Contents

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

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

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

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

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

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

Table of Contents

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

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

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

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

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

Table of Contents

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

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

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

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

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

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

- the operation of and emissions from regulated units;

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

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

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

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

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

- the availability and cost of carbon control technology;

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

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

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

The U.S. EPA finalized two rules that are relevant to emissions of SO_2 , NO_x , PM and mercury from our U.S. coal-fired power plants. The first rule, the Clean Air Interstate Rule (CAIR), was promulgated by the EPA on March 10, 2005, and required allowance surrender for SO_2 and NO_x emissions from existing power plants located in 28 eastern states and the District of Columbia. CAIR contemplated two implementation phases. The first phase was to begin in 2009 and 2010 for NO_x and SO_2, respectively. A second phase with additional

Table of Contents

allowance surrender obligations for both air emissions was to begin in 2015. To implement the required emission reductions for this rule, the states were to establish emission allowance-based cap-and-trade programs. CAIR was subsequently challenged in federal court and on July 11, 2008, the U.S. Court of Appeals for the D.C. Circuit issued an opinion striking down CAIR. On December 23, 2008, in response to motions from the EPA and other petitioners, the Court issued an opinion and remanded the rule to the EPA without vacatur to enable the EPA to remedy CAIR s flaws in accordance with the Court s July opinion. The EPA plans to issue a proposed revision to CAIR in the spring of 2010. In the interim, until EPA finalizes a new rule to replace CAIR, the Company and a number of its subsidiaries are operating subject to the remanded CAIR.

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

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

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

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

In 2005, the Company entered into a Consent Decree (the 2005 Consent Decree) with the State of New York, and New York State Electric and Gas Corporation (NYSEG) which resolves violations of CAA requirements alleged to have occurred at the Greenidge, Westover, Jennison and Hickling plants prior to the Company s acquisition of such plants. Under the terms of the 2005 Consent Decree, the Company is required to

Table of Contents

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

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

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

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

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

Table of Contents

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

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

Table of Contents

ITEM 1A. RISK FACTORS

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

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

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

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

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

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

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

- negative publicity;

Table of Contents

ratings downgrades; or

the loss or impairment of investor confidence in the Company.

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

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

Risks Related to our High Level of Indebtedness

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

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

making it more difficult to satisfy debt service and other obligations at the holding company and/or individual subsidiaries;

increasing the likelihood of a downgrade of our debt, which could cause future debt costs and/or payments to increase and consume an even greater portion of cash flow;

increasing our vulnerability to general adverse economic and industry conditions;

reducing the availability of cash flow to fund other corporate purposes and grow our business;

limiting our flexibility in planning for, or reacting to, changes in our business and the industry;

placing us at a competitive disadvantage to our competitors that are not as highly leveraged; and

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

(all amounts in thousands, except per share and share data)

Table of Contents

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

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

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

However, our subsidiaries face various restrictions in their ability to distribute cash to The AES Corporation. Most of the subsidiaries are obligated, pursuant to loan agreements, indentures or project fiFONT>

Balance at October 31, 2003	(321)
Use of reserved inventory	99
Balance at October 31, 2004	$ (222)

7. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is summarized by major classification as follows:

	October 31, 2004	October 31, 2003
Land and improvements	$ 488	$ 497
Buildings and improvements	3,977	3,436
Plant machinery and equipment	10,857	10,497
Furniture and fixtures	580	326
Coach fleet and vehicles	16,171	15,982
Coach refurbishments	566	474
Total	32,639	31,212
Less accumulated depreciation	(8,909)	(6,732)
Net property, plant and equipment	$ 23,730	$ 24,480

7. PROPERTY, PLANT AND EQUIPMENT, CONTINUED

Depreciation expense of property, plant and equipment for the years ended October 31, 2004, 2003, and 2002 included in continuing operations was $2,678, $2,401, and $2,128, respectively. During 2004, certain equipment became idle due to the realignment of the plant at U.S. Rubber. The equipment will be used in the future for replacement of existing equipment as needed. Due to the uniqueness of the equipment and the high cost to buy new similar pieces, the net book value of $353 was transferred to other assets under idle equipment and is subject to impairment valuation.

8. FINANCING ARRANGEMENTS

The Company has the following outstanding debt as of October 31, 2004 and 2003:

	Debt Amount	
	October 31, 2004	**October 31, 2003**
U.S. Rubber		
Line of credit issued by a bank, bearing interest at prime plus 0.5% (5.25% at October 31, 2004), borrowings not to exceed the greater of $4,000 or the borrowing base (85% of eligible accounts receivable and 42% of eligible inventories), interest payable monthly, balance due October 2005, collateralized by substantially all assets of U.S. Rubber	$ 2,403	$ 2,059
Note payable to a bank, interest payable monthly at prime plus 1% (5.75% at October 31, 2004), monthly principal payments of $48, due October 2005, collateralized by substantially all assets of U.S. Rubber	2,905	3,476
Note payable to DC Investments, interest payable monthly at 15%, balloon payment due March 2007, subordinate to bank debt	700	700
Other	19	50
Subtotal U.S. Rubber	6,027	6,285

U.S. Rubber's debt is subject to financial covenants, the most restrictive of which is a fixed charge coverage ratio.

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

8. FINANCING ARRANGEMENTS, CONTINUED

	Debt Amount

(all amounts in thousands, except per share and share data)

	October 31, 2004	October 31, 2003
Pyramid, DW Leasing, Obsidian Leasing and DC Investments Leasing		
Various installment loans, repayable in monthly installments totaling $151 including interest ranging from the three-month LIBOR rate plus .12% (1.987% at October 31, 2004) to 13.1% through January 2014 and applicable balloon payments thereafter through January 2014, less unamortized discount ($30 at October 31, 2004) first lien on assets financed (finance acquisition and asset purchases). A portion of the borrowings guaranteed by the members of DW Leasing, Fair Holdings, DC Investments, and its partners.	$ 10,342	$ 11,186
Notes payable to Fair Holdings, repayable in monthly installments of interest ranging from 10% to 14% through October 2012 and applicable balloon payments through December 2012. Collateralized by all assets of the borrower, collateral position second to that of senior lender.	4,669	4,056
Other	23	31
Subtotal Pyramid, DW Leasing, Obsidian Leasing and DC Investments Leasing	15,034	15,273

The Coach Leasing segment s debt is subject to financial covenants, the most restrictive of which is cash flow coverage ratio and debt service coverage.

8. FINANCING ARRANGEMENTS, CONTINUED

	Debt Amount	
	October 31, 2004	October 31, 2003
Danzer		
Line of credit to Fair Holdings, maximum borrowing equal to $3,000, interest payable monthly at the LIBOR Daily Floating Rate plus 3.2% (5.187% at October 31, 2004), due April 2006. Collateralized by substantially all assets of Danzer.	$ 2,253	$ 1,331

	Debt Amount	
Note payable to Fair Holdings, requires monthly principal installments of $6, interest accrues at the LIBOR Daily Floating Rate plus 3.2% (5.187% at October 31, 2004), due April, 2006. Collateralized by substantially all assets of Danzer.	894	961
Term loans payable to US Amada, Ltd. Monthly payments currently aggregating $13 including interest at 10%, loans due January 2003, collateralized by equipment financed, paid in December 2003.	---	14
Equipment loans payable---monthly payments currently aggregating $2 including interest of 9.50% to 11.30% through November 2007. Collateralized by equipment financed.	58	85
Other	13	19
Subtotal Danzer	3,218	2,410

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

8. FINANCING ARRANGEMENTS, CONTINUED

	Debt Amount	
	October 31, 2004	**October 31, 2003**
United		
Line of credit to a bank, maximum borrowing equal to $4,000, with a base of 80% of eligible accounts receivable plus 50% of raw material, work-in-process and finished goods inventory. Interest payable monthly at prime plus .75% (5.5% at October 31, 2004), due November 1, 2004. Collateralized by substantially all assets of United and guaranteed by Obsidian Enterprises*. Line of credit has matured and United is currently working on a forebearance agreement with the bank as well as looking to refinance with another lender.	$ 4,000	$ 4,000
Temporary overline of credit with bank, interest payable monthly at prime plus .75% (5.5% at October 31, 2004), due on demand, collateralized by substantially all assets of United and guaranteed by Obsidian Enterprises paid in April 2004.	---	250
Notes payable to a bank, requires monthly principal installments of $11 plus		

	Debt Amount	
interest of prime plus 1% (5.75% at October 31, 2004), due through July 2006, collateralized by substantially all assets of United and guaranteed by Obsidian Enterprises*.	987	1,484
Subordinated note payable to Huntington Capital Investment Company, interest payable quarterly at 14% per annum, balloon payment of outstanding principal balance due July 26, 2006, less unamortized discount ($794 and $1,091 at October 31, 2004 and 2003, respectively). Unsecured and subordinate to line of credit and notes payable above.*	2,706	2,409
Note payable to former shareholder, interest payable monthly at 9% per annum, balloon payment of outstanding principal balance due July 27, 2006. Unsecured and subordinate to line of credit, notes payable and Huntington debt above.*	1,500	1,500
Note payable to Renaissance, interest payable monthly at 8% per annum, with monthly principal payments of $5 beginning July 2004, due July 2008. Convertible at the option of the holder to common stock of Obsidian Enterprises at a conversion price of $5.00 per share. The loan agreement also restricts dividend payments without the prior consent of the lender.	500	500

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

8. FINANCING ARRANGEMENTS, CONTINUED

	Debt Amount	
	October 31, 2004	October 31, 2003
United, continued		
Other	79	122
Subtotal United	9,772	10,265

*United was in technical default of certain loan covenants with its senior and subordinated lender at October 2004

Obsidian Enterprises

Line of credit to Fair Holdings, maximum borrowing equal to $15,000, interest payable monthly at 10%, due January 2007, collateralized by all assets of

	Debt Amount	
Obsidian Enterprises and personally guaranteed by certain officers.	10,815	6,045
Note payable to Fair Holdings, interest payable monthly at 15%, balloon payment due March 2007, personally guaranteed by certain officers.	934	803
Subtotal Obsidian Enterprises	11,749	6,848

United's debt is subject to financial covenants, the most restrictive of which is a fixed charge ratio and funded debt to EBITDA.

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

8. FINANCING ARRANGEMENTS, CONTINUED

	Debt Amount	
	October 31, 2004	**October 31, 2003**
Classic		
Line of credit to a bank, maximum borrowing equal to the lesser of $1,000 or 85% of eligible accounts receivable plus the lesser of 60% of all outstanding line of credit advances, $500, or the sum of 60% of finished goods and raw material eligible inventory plus the lesser of 60% of work-in-process eligible inventory or $90 minus inventory reserves. Interest payable monthly at prime plus 0.5% (5.25% at October 31, 2004), due May 1, 2006. Collateralized by substantially all assets of Classic and guaranteed by Obsidian Enterprises and the Chairman of Obsidian Enterprises.	580	---
Notes payable to a Bank, monthly principal installments of $2 plus interest at prime plus 0.5% (5.25% at October 31, 2004), due through May 1, 2009 Collateralized by substantially all assets of Classic and guaranteed by Obsidian Enterprises and certain officers.	96	---
Notes payable to a Bank, monthly principal installments of $23 plus interest at prime plus 1% (5.75% at October 31, 2004), due through May 1, 2007 Collateralized by substantially all assets of Classic and guaranteed by Obsidian Enterprises and certain officers.	714	---
Other	39	---

	Debt Amount	
Subtotal Classic	1,429	---
Total all companies	47,229	41,081
Less related-party amounts presented separately	(20,299)	(13,937)
Less current portion	(18,383)	(2,379)
	$ 8,547	$ 24,765

Classic's debt is subject to financial covenants, the most restrictive of which is a leverage ratio and a fixed charge coverage ratio.

Following are the maturities of long-term debt for each of the next five years and thereafter:

2005	$ 18,383
2006	7,330
2007	15,979
2008	3,412
2009	100
Thereafter	2,025
	$ 47,229

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

8. FINANCING ARRANGEMENTS, CONTINUED

The Company has an agreement with Obsidian Capital Partners (Partners) that gives the Company the right to mandate a capital contribution from Partners if the lenders to U.S. Rubber and/or United were to declare a default. In that event, the Company has the right to enforce a capital contribution agreement with Partners and to receive a capital contribution in amounts up to $1,370 for U.S. Rubber and $1,000 for United to fund the respective subsidiary s shortfall. Those payments, if any, would be applied directly to reduce the respective subsidiary s debt obligations to the lender. During fiscal 2003, a capital call was made for $250 for U.S. Rubber to bring the Company in compliance with certain bank covenants. Partners received 14,285 shares of Series D Preferred Stock in exchange for the capital call.

The following details significant changes in debt during the year ended October 31, 2004, or subsequent thereto:

FINANCIAL COVENANTS

Significant financial covenants in our credit agreements are the maintenance of minimum ratios, levels of earnings to funded debt and fixed charge coverage ratios. The Company did not meet requirements and covenants in certain debt agreements.

At October 31, 2004, United did not meet financial covenants with its Bank and Huntington Capital Investment Company. United did not meet its EBITDA and fixed charge coverage ratios. The Capital Investment Company waived their covenant violations as of October 31, 2004. The amount for the Capital Company is classified as current until completion of an amendment to cure future violations. The bank debt has matured and the Company is currently working with the bank on a short term extension until it is refinanced. The total debt of $7,693 is classified as current.

Obsidian Leasing was notified by its lender by letter dated November 3, 2004 that it was in technical default of its fixed charge coverage ratio under its promissory notes with a bank and that the maturity date of the related promissory notes were being accelerated, making the notes due an payable on December 1, 2004. The Company is currently discussing a forbearance agreement and the total related debt of $3,430 is classified as current. Management is currently exploring options with regard to refinancing the outstanding debt. Should refinancing or an extension of the current agreement not be obtained by the expiration date of the forbearance agreement, the debt will be repaid through current sources of availability including borrowings under the Company s line of credit with Fair Holdings.

US Rubber did not meet financial its covenant related to delivery of audited statements within 90 days. No waiver was received and the total balance of $5,307 is classified as current.

Obsidian Enterprises did not meet financial its covenant related to minimum working capital requirement and delivery of audited statements within 90 day covenants with RENN Capital. No waiver was received and the total balance of $500 is classified as current.

PYRAMID, DW LEASING, OBSIDIAN LEASING AND DC INVESTMENTS LEASING:

On January 3, 2003, Obsidian Leasing paid off debt in the amount of $928 to former shareholders of Pyramid and related companies with proceeds from a note with Fair Holdings which includes monthly interest payments of 13% of the outstanding principal amount and a balloon principal payment in January 2006.

On December 17, 2002, Obsidian Leasing sold four coaches to DC Investments Leasing in exchange for DC Investments Leasing s satisfaction of the debt outstanding on such coaches. In addition, DC Investments Leasing also acquired five additional coaches that were previously to be purchased by the Company, thereby eliminating the Company s existing purchase commitment for such coaches. The Company refinanced the debt on the four coaches in addition to financing the five additional coaches. DC Investments Leasing entered into an agreement with First Indiana for $2,741 of the debt with interest payable at prime plus ½% and a maturity of December 2007. DC Investments Leasing also incurred debt with Fair Holdings for the remaining 20% of the net book value of the transferred and new coaches. Terms of the debt with Fair Holdings include monthly interest payments on the principal amount of $677 at 14% and a maturity of January 2008. DC Investments Leasing also entered into a management agreement with Pyramid under which all nine coaches described above will be leased by Pyramid.

8. FINANCING ARRANGEMENTS, CONTINUED

DANZER:

As of January 31, 2003, Danzer was in violation of certain covenants included in its credit agreement and First Forbearance Agreement dated October 14, 2002 with its senior lender. On February 28, 2003, the Company and the lender entered into a Second Forbearance Agreement waiving these violations. On March 28, 2003, the credit agreement was assumed by Fair Holdings under an assumption and continuation agreement. An amendment was made as of the effective date of the agreement to extend the maturity date of the line of credit agreement to April 1, 2006 and the debt covenants required by the senior lender were waived through the end of the term. In September 2003 the line of credit was amended to increase the total availability from $1,000 to $1,500. All other terms of the agreement will continue as stated in the original agreement dated August 15, 2001.

In July 2004 the Fair Holdings line of credit was amended to increase the total availability from $1,500 to $3,000. All other terms of the agreement will continue as stated in the original and amended agreement dated August 15, 2001.

UNITED:

On December 26, 2002, United amended its credit agreement to provide additional working capital. The amendment included a temporary overline line of credit with maximum borrowings not to exceed the lesser of $650 or the remainder of the borrowing base less the outstanding principal amount of the revolving line of credit. Interest is payable monthly at a rate of prime plus 0.75%.

On January 28, 2004, United amended its line of credit agreement to extend the maturity date of the original $4,000 line to November 2004, to waive United s current debt violations, and to modify the covenants for future reporting periods. The bank debt has matured and United is currently working with the bank on a short term extension until it is refinanced. United is in negotiations for a new line of credit and term loan with a different lender. United expects to complete the refinancing of this debt during the first half of fiscal 2005.

CLASSIC:

On December 28, 2004, the credit agreement was temporarily amended to increase the borrowing base through April 1, 2005 to the following: The borrowing base is equal to 85% of eligible accounts receivable plus the lesser of 75% of all outstanding line of credit advances, $750, or the sum of 60% of finished goods and raw material eligible inventory plus the lesser of 60% of work-in-process eligible inventory or $90 minus inventory reserves. On April 1, 2005, the borrowing base will revert to the original agreement.

OBSIDIAN ENTERPRISES:

In fiscal 2004, Obsidian Enterprises line of credit with Fair Holdings was amended. Maximum borrowings were increased from $8,000 to $15,000, and the maturity date was extended from January 2005 to January 2007.

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

9. LEASING ARRANGEMENTS

The Company has various operating lease commitments, principally related to machinery and equipment, office equipment, and facilities. The approximate future minimum annual rentals under the terms of these leases, which expire on various dates through the year ending October 31, 2012, are as follows:

Year Ending October 31,	Third Party	Related Party	Total
2005	$ 359	$ 144	$ 503
2006	303	144	447
2007	234	144	378
2008	54	144	198
2009 and thereafter	228	360	588
Total	$ 1,178	$ 936	$ 2,114

Rental expense under operating leases for the years ended October 31, 2004, 2003, and 2002 was $658, $594, and $562, respectively. Rental expense under a month to month lease with Fair Holdings for the years ended October 31, 2004, 2003 and 2002 was $64, $31 and none, respectively.

10. EMPLOYEE BENEFIT PLANS

The Company, through certain of its subsidiaries, has defined contribution 401(k) plans which permit voluntary contributions up to 20% of compensation and which provide Company-matching contributions of up to 10% of employee contributions not to exceed 6% of employee compensation. 401(k) plan expense for the years ended October 31, 2004, 2003, and 2002 was approximately $102, $128, and $148, respectively. The Company s health insurance is through a partially self funded plan which has a maximum claim limit of $70 per employee. Claims in excess of these limits are reimbursed by a separate re-insurance plan which carries a plan limit of $1,000.

11. REDEEMABLE STOCK

In conjunction with the United acquisition in 2001, the Company issued 154,482 shares of Common Stock to Huntington Capital Investment Corporation (Huntington), the senior subordinated lender of United. The note purchase agreement included a provision giving Huntington the option to require the Company to repurchase these shares at 90% of market value at the date of redemption upon the earlier of: a) fifth anniversary of issuance of such shares, b) default under the subordinated debt agreement, c) other factors related to a sale of substantially all assets of the Company as defined in the agreement.

A portion of the note purchase agreement proceeds of $3,500 was allocated to the stock issued based on the thirty day average closing value of the Company s common stock prior to the transaction. As the redemption value is variable, the Company recognizes changes in the estimated fair value each quarter. Changes in fair value are adjusted through additional paid in capital or retained earnings when additional paid in capital related to the fair value change has been reduced to zero. At October 31, 2004, the estimated redemption requirement is $443 to be paid July 2006.

In conjunction with the sale of Champion discussed in Note 4, the Company agreed to settle the outstanding subordinated debt due to Markpoint from Champion in exchange for a cash payment of $675 and issuance to the debt holder of 32,143 shares of the Company s Series D Preferred Stock. The agreement provided Markpoint the option to require the Company to repurchase these shares at a price of $21 per share. The repurchase option was available to Markpoint as follows: 16,072 shares during the period May 1, 2003 to June 1, 2003 and 16,071 shares during the period November 1, 2003 to December 1, 2003. On May 12, 2003, under an Assignment Agreement, the Company transferred all rights, title and interest in the repurchase option to Fair Holdings. Markpoint exercised the repurchase option and was paid $338 by Fair Holdings. The exercise of the option resulted in the reduction of the liability and an increase in additional paid in capital of $337 as of October 31, 2003. On November 10, 2003, Markpoint exercised the option for the remaining shares and those shares also were acquired by Fair Holdings. The exercise of the option resulted in a reduction in redeemable stock and an increase in additional paid-in capital of $337.

---

11. REDEEMABLE STOCK, CONTINUED

With the acquisition of Classic effective May 1, 2004, the Company issued 170,451 shares of our common stock to the former owners of Classic. These shares are classified as redeemable stock. The purchase agreement for Classic included a provision that gives the sellers the right to have us redeem these shares at a price of $6.5970 per share within five years of the date of issuance of the shares. The sellers have the right to partially redeem these shares in increments of 10,000 or more shares per transaction. The agreement also has an automatic termination provision if the Company s shares have traded at a closing price of greater than $7.33 per share for any consecutive period of 60 trading days during the period of time commencing on the date there are no restrictions on the sellers sale of shares and ending on the fifth anniversary of the agreement.

12. STOCKHOLDERS EQUITY

PREFERRED STOCK:

On March 7, 2002, the Company completed a series of transactions with the subordinated lender at U.S. Rubber resulting in an increase in equity and a decrease in liabilities of $1,017. The subordinated lender received 30,000 shares of Series C Preferred Stock in this transaction.

On April 30, 2002, the Company converted $1,290 of debt and accrued interest owed to Partners and $596 of debt and accrued interest owed to Fair Holdings to equity through the issuance to Partners and Fair Holdings of 402,906 shares and 186,324 shares, respectively, of Series C Preferred Stock which are convertible into an aggregate of 11,784,600 shares of common stock of the Company.

In August 2002, warrants for 10,000 shares of Series C Convertible Stock were exercised. The shares were issued in exchange for a cash payment of $20.

On October 24, 2002, the Company amended its Articles of Incorporation to authorize 200,000 shares of Series D Preferred Stock. The Series D Preferred Stock is convertible at the option of the holder at any time, unless previously redeemed, into shares of common stock of the Company at an initial conversion rate of 175 shares of common stock for each share of Series D Preferred Stock. However, the stock may not be converted prior to the Company filing a registration statement for such shares. Holders of the Series D Preferred Stock have voting rights which entitle them to cast the number of votes equal to the number of shares of common stock into which such shares of Series D Preferred could be converted on each matter submitted to a vote of the stockholders of the Company.

On October 24, 2002, 88,300 of the Series D Preferred Stock shares were sold in the transactions described below which were exempt from Securities Act registration under Section 4(2) of the Securities Act, relating to sales by an issuer not involving a public offering.

On October 24, 2002, the Company converted $1,276 of debt to Partners in exchange for 72,899 shares of Series D Preferred Stock. The conversion was the result of Partners requirement under the Agreement and Plan of Reorganization between the Company and U.S. Rubber to fund through the purchase of additional preferred stock certain ongoing administrative expenses of the Company to complete the Plan of Reorganization, complete all required current and prior year audits to meet the regulatory filing requirements, and ensure all annual and quarterly SEC filings are completed to enable the registration of the preferred stock issued to Partners.

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

12. STOCKHOLDERS EQUITY, CONTINUED

On October 24, 2002, the Company converted $270 of debt to Fair Holdings in exchange for 15,431 shares of Series D Preferred Stock. The conversion was the result of Fair Holding s agreement to cover similar expenses as Partners as described above in excess of the amount Partners was obligated to pay.

On May 12, 2003, 16,072 shares of Series D Preferred Stock, previously classified as redeemable stock (see Note 11) were acquired by Fair Holdings from Markpoint.

On October 13, 2003, the Company issued 14,285 shares of Series D Preferred Stock for $250. The issuance was as a result of a capital call from Partners who were obligated to fund additional capital required to maintain compliance with the debt covenants of U.S. Rubber.

On December 3, 2003, the Company s stockholders and Board of Directors approved a 50-to-1 reverse stock split. The reverse stock split was effective for trading purposes as of February 16, 2004. As a result of the reverse stock split and the amendment to the Certificate of Incorporation, approximately 720,157 shares of common stock remained outstanding and the number of authorized shares of common stock was reduced to 10,000,000.

On March 12, 2004, all outstanding Series C and D preferred shares were converted to common stock, which increased common stock outstanding by 2,218,725 shares including 154,482 shares classified as redeemable stock. As of October 31, 2004, there were five million shares authorized with no preferred shares issued or outstanding.

STOCK OPTIONS:

The stockholders approved a stock option plan to issue both qualified and nonqualified stock options. Under the plan, 16,000 options to purchase shares of the Company s common stock may be issued at the discretion of the Company s Board of Directors. The option price per share is determined by the Company s Board of Directors, but in no case will the price be less than 85% of the fair value of the common stock on the date of grant. Options under the plan will have a term of not more than ten years with accelerated termination upon the occurrence of certain events.

The Board adopted, and the Company s stockholders approved a 2001 Long Term Incentive Plan. The 2001 Plan authorizes the granting to the Company s directors, key employees, advisors and consultants of options intended to qualify as Incentive Options within the meaning of Section 422 of the Internal Revenue Code of 1986, as amended (the Code), options that do not so qualify (Non-Statutory Options), restricted stock and Other Stock-Based Awards that are not Incentive Options or Non-Statutory Options. The awards are payable in Common Stock and are based on the formula which measures performance of the Company. There was no performance award expense in 2004, 2003 or 2002. No options under this plan were granted to any employees. Options are exercisable for up to 10 years from the date of grant.

On December 13, 2003, the Company s Board of Directors approved the extension of the expiration date of 4,000 fixed stock options, exercisable at $2.50. The original expiration date of December 31, 2002 was originally extended to December 31, 2003 and subsequently to June 30, 2004. The Company recognized $30 and $40 respectively of compensation expense related to the extension of the options during the years ended October 31, 2003 and 2004. The fixed stock options expired and were not exercised as of June 30, 2004.

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

12. STOCKHOLDERS EQUITY, CONTINUED

Following is a summary of transactions of granted shares under option and adjusted for the 50:1 reverse stock split in February 2004 for the years ended October 31, 2004, 2003 and 2002:

	2004		2003		2002	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding, beginning of year	16,000	4.50	16,000	4.50	20,950	4.50
Issued during the year	---	---	---	---	---	---
Canceled or expired during the year	(16,000)	4.50	---	---	(4,950)	5.00
Exercised during the year	---	---	---		---	---
Outstanding, end of year	---	---	16,000	4.50	16,000	4.50
Eligible, end of year for exercise	---	---	16,000	4.50	16,000	4.50

STOCK WARRANTS:

The Company has issued warrants to purchase common stock to several parties. In January 2003, the Company agreed to a modification of terms with the debenture holders to provide for less stringent covenants. In exchange for this modification, the Company issued warrants to the debenture holders to purchase up to 320 shares of the Company s common stock at an exercise price of $10.00 per share. These warrants expire

January 24, 2006. In February 2004, the Company received an extension of the requirement to provide audited financial statements to debenture holders. In exchange for this extension, the Company issued warrants to each of the debenture holders to purchase up to 160 shares of the Company s common stock at an exercise price of $10.00 per share. These warrants expire February 9, 2007. The issuance of the warrants had no material impact on earnings.

The following table summarizes the outstanding warrants for the years ended October 31, 2004 and 2003:

	Outstanding Warrants October 31, 2002	Issued During the Year	Exercise Price	Warrants Exercised in Period	Outstanding Warrants October 31, 2003 and 2004
Common Stock:					
Renaissance US Growth & Income Trust PLC	160	160	10.00	---	320
BFSUS Special Opportunities Trust PLC	160	160	10.00	---	320

	Outstanding Warrants October 31, 2001	Issued During the Year	Exercise Price	Warrants Exercised in Period	Outstanding Warrants October 31, 2002
Common Stock:					
Renaissance US Growth & Income Trust PLC	---	160	10.00	---	160
BFSUS Special Opportunities Trust PLC	---	160	10.00	---	160

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

CONVERTIBLE DEBT:

As described in Note 8, the Company has a note payable agreement which is convertible by the holder to common stock totaling 100,000 shares at a conversion rate of $5.00 per share.

13. BUSINESS SEGMENT DATA AND GEOGRAPHIC DATA

The Company operates in three industry segments comprised of trailer and related transportation equipment manufacturing; coach leasing; and butyl rubber reclaiming. All sales are in North and South America primarily in the United States, Canada and Brazil. All segment information is presented from continuing operations and before cumulative effect of change in accounting method. Selected information by segment follows:

	Year Ended October 31, 2004					
	Trailer Manufacturing	Coach Leasing	Butyl Rubber Reclaiming	Total Segments	Corporate	Consolidated
Sales:						
Domestic	$ 43,037	$ 5,464	$ 9,499	$ 58,000	$ ---	$ 58,000

	Year Ended October 31, 2004					
Foreign	5,147	---	1,213	6,360	---	6,360
Total	$ 48,184	$ 5,464	$ 10,712	$ 64,360	$ ---	$ 64,360
Cost of goods sold	$ 44,116	$ 3,216	$ 10,472	$ 57,804	$ ---	$ 57,804
Loss before taxes and minority interest	$ (4,110)	$ (1,574)	$ (1,606)	$ (7,290)	$ (694)	$ (7,984)
Identifiable assets	$ 24,941	$ 14,132	$ 10,562	$ 49,635	$ (216)	$ 49,419
Goodwill	$ 7,055	$ ---	---	$ ---	---	7,055
Depreciation and amortization expense	$ 903	$ 1,004	$ 1,450	$ 3,357	$ 142	$ 3,499
Interest expense	$ 1,606	$ 1,362	$ 494	$ 3,462	$ 703	$ 4,165

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

13. BUSINESS SEGMENT DATA AND GEOGRAPHIC DATA, CONTINUED

	Year Ended October 31, 2003					
	Trailer Manufacturing	**Coach Leasing**	**Butyl Rubber Reclaiming**	**Total Segments**	**Corporate**	**Consolidated**
Sales:						
Domestic	$ 37,590	$ 7,281	$ 9,893	$ 54,764	$ ---	$ 54,764
Foreign	3,419	---	1,112	4,531	---	4,531
Total	$ 41,009	$ 7,281	$ 11,005	$ 59,295	$ ---	$ 59,295
Cost of goods sold	$ 37,704	$ 4,060	$ 9,972	$ 51,736	$ ---	$ 51,736
Loss before taxes and minority interest	$ (3,480)	$ (122)	$ (752)	$ (4,354)	$ (235)	$ (4,589)
Identifiable assets	$ 19,722	$ 14,147	$ 11,028	$ 44,897	$ 985	$ 45,882

	Year Ended October 31, 2003					
Goodwill	$ 5,784	$ ---	$ ---	$ ---	$ ---	$ 5,784
Depreciation and amortization expense	$ 751	$ 767	$ 1,332	$ 2,850	$ ---	$ 2,850
Interest expense	$ 1,395	$ 1,189	$ 556	$ 3,140	$ 407	$ 3,547

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

13. BUSINESS SEGMENT DATA AND GEOGRAPHIC DATA, CONTINUED

	Year Ended October 31, 2002					
	Trailer Manufacturing	**Coach Leasing**	**Butyl Rubber Reclaiming**	**Total Segments**	**Corporate**	**Consolidated**
Sales:						
Domestic	$ 38,911	$ 6,374	$ 9,336	$ 54,621	$ ---	$ 54,621
Foreign	1,864	---	789	2,653	---	2,653
Total	$ 40,775	$ 6,374	$ 10,125	$ 57,274	$ ---	$ 57,274
Cost of goods sold	$ 35,077	$ 3,357	$ 9,407	$ 47,841	$ ---	$ 47,841
Loss before taxes and minority interest	$ (1,966)	$ (417)	$ (732)	$ (3,115)	$ (193)	$ (3,308)
Identifiable assets	$ 20,155	$ 11,760	$ 11,391	$ 43,306	$ 2,617	$ 45,923
Goodwill	$ 5,784	$ ---	$ ---	$ ---	$ ---	$ 5,784
Depreciation and amortization expense	$ 705	$ 779	$ 1,084	$ 2,568	$ ---	$ 2,568
Interest expense	$ 1,277	$ 1,468	$ 614	$ 3,359	$ 193	$ 3,552

Obsidian Enterprises (legal parent) allocates selling, general and administrative expenses to the respective companies primarily based on a percentage of sales. For the years ended October 31, 2004, 2003, and 2002, respectively, allocated corporate expenses by segment were as follows:

	Year Ended October 31,		
	2004	**2003**	**2002**

	Year Ended October 31,		
Trailer manufacturing	$ 2,280	$ 1,174	$ 934
Coach leasing	259	200	146
Butyl rubber reclaiming	507	317	232
	$ 3,046	$ 1,691	$ 1,312

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

14. INCOME TAXES

The Company files a consolidated federal tax return. The parent and each subsidiary record their share of the consolidated federal tax expense on a separate-return basis. Any additional income tax expense or recovery realized as a result of filing a consolidated tax return is recorded in consolidation. The Company and each subsidiary file separate state income tax returns. The Company accounts for income taxes in compliance with SFAS No. 109, *Accounting for Income Taxes*. Under SFAS No. 109, deferred tax assets and liabilities are recorded for any temporary differences between the financial statement and tax bases of assets and liabilities, using the enacted tax rates and laws expected to be in effect when the taxes are actually paid or recovered.

The provision for (expense) benefit for income taxes consists of the following:

	2004	2003	2002
Current:			
Federal	$ ---	$ ---	$ ---
State	(48)	(66)	(15)
	(48)	(66)	(15)
Deferred:			
Federal	61	733	41
State	10	270	7
Discontinued operations	---	25	332
	71	1,028	380
Total tax benefit	23	962	365

	2004	2003	2002
Less tax benefit from discontinued operations	---	(25)	(332)
Tax benefit from continuing operations	$ 23	$ 937	$ 33

A reconciliation of income tax benefit (expense) from continuing operations at U.S. statutory rates to actual income tax benefit (expense) is as follows:

	2004	2003	2002
Benefit (tax) at statutory rate (34%)	$ 2,714	$ 1,536	$ 1,125
Effect of nontaxable combined entity	(10)	138	(18)
State income tax	273	180	(15)
Non-deductible goodwill	---	---	(245)
Valuation reserve applied to equity	---	---	(1,267)*
(Increase) decrease in valuation reserve	(2,901)	(1,028)	380
Other	(53)	111	73
	$ 23	$ 937	$ 33

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

14. INCOME TAXES, CONTINUED

*On November 1, 2001, 27 coaches owned by DW Leasing were transferred to Obsidian Leasing in a tax-free exchange, as further described in Note 1. DW Leasing recorded a charge to equity as a deemed distribution of $1,590 on the date of the transaction, representing the deferred tax liability associated with the coaches transferred. A reduction of deferred tax valuation reserve of $(1,267) was also recorded in the consolidated financial statements as an increase in equity, as the addition of the above deferred tax liability resulted in the Company s ability to realize additional deferred tax assets on a consolidated basis.

Deferred income taxes represent the net tax effects of temporary differences between the carrying amount of assets and liabilities for financial reporting purposes and for income tax purposes. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some or all of a portion of the deferred tax assets will not be realized. Significant components of the Company s deferred tax assets and liabilities are as follows:

	2004	2003
Deferred tax assets (liabilities):		
Accounts receivable	$ 233	$ 195
Inventories	203	215

(all amounts in thousands, except per share and share data)

	2004	2003
Accrued expenses	199	143
Intangibles	251	370
Operating loss carryforwards	8,294	5,209
Property and equipment	(4,634)	(4,272)
Other	25	10
	4,571	1,870
Less valuation reserves	(4,872)	(1,971)
Deferred tax assets (liabilities), net	$ (301)	$ (101)

Included in the accompanying balance sheet under the following:

	2004	2003
Deferred tax assets	$ 635	$ 550
Deferred tax liabilities	(936)	(651)
	$ (301)	$ (101)

The amount of federal tax net operating loss carryforwards available at October 31, 2004 was approximately $21,500. Certain of these loss carryforwards were generated by certain subsidiaries prior to the reverse merger transaction in June 2001 and have expiration dates through the year 2021. The use of preacquisition operating losses is subject to limitations imposed by the Internal Revenue Code. Utilization of these loss carryforwards is impacted by such limitations. Accordingly, the deferred tax assets related to premerger operating losses have been reserved with a valuation allowance to the extent they are not offset by deferred liabilities.

14. INCOME TAXES, CONTINUED

Federal tax net operating loss carryforwards and expiration dates as of October 31, 2004 are as follows:

Premerger	Expiration Dates	Postmerger	Expiration Dates
$ 2,996	2008 through 2021	$ 18,517	2021 through 2024

Cash payments of income taxes for the years ended October 31, 2004, 2003, and 2002 were $75, $96, and $22, respectively.

15. RELATED PARTIES

(all amounts in thousands, except per share and share data)

The Company makes advances, receives loans and conducts other business transactions with affiliates resulting in the following amounts for the periods ended:

	October 31, 2004	October 31, 2003
Balance sheets:		
Current assets:		
Accounts receivable, Obsidian Capital Company[(2)]	$ 8	$ 8
Accounts receivable, stockholders	11	---
Accounts receivable, other affiliated entities	52	44
Total assets	$ 71	$ 52
Current liabilities:		
Accounts payable, Obsidian Capital Company[(2)]	$ 35	$ 275
Accounts payable, stockholders	3	320
Accounts payable, DC Investments and Fair Holdings[(2)]	1,181	221
Accounts payable, other affiliated entities	49	21
Long-term portion:		
Accounts payable, Obsidian Capital Company[(2)]	240	---
Accounts payable, stockholders	316	---
Notes payable, DC Investments[(2)]	700	700
Notes payable, Fair Holdings[(2)]	8,784	7,192
Line of credit, Fair Holdings[(2)]	10,815	6,045
Total liabilities	$ 22,123	$ 14,774

15. RELATED PARTIES, CONTINUED

	October 31, 2004	October 31, 2003	October 31, 2002
Statements of Operations:			
Interest expense, DC Investments and Fair Holdings[(2)]	$ 1,751	$ 1,274	$ 322
Interest expense, Obsidian Capital Partners[(2)]	---	---	58
Rent expense, Fair Holdings[(2)]	54	45	---
Rent expense, Obsidian Capital Company[(2)]	---	---	56
Sales to Champion[(2)]	60	---	---

(all amounts in thousands, except per share and share data)

	October 31, 2004	October 31, 2003	October 31, 2002
Purchases from Champion[2]	137	---	---
Rent expense, Roost Leasing[1]	72	---	---
Purchases, CCG Parma[2]	11	---	---
Other:			
Coach rebuild, Champion	185	---	---
Classic acquisition costs, Diamond Investments, LLC(2)	51	---	---

[1]A leasing company owned by the former owners of Classic
[2]An entity controlled by Tim Durham, the Chairman of Obsidian Enterprises

Related-party amounts classified as current reflect those portions of the total receivable or payable that were currently due in accordance with the terms, or were collected or paid subsequent to year end. Amounts classified as long term represent amounts not currently due.

On February 13, 2002, DC Investments, a related party 50% owned by Mr. Durham (Chairman of the Company), purchased accounts receivable from DW Leasing, recorded by DW Leasing as deposits on trailers, in the amount of $1,051. DW Leasing used the proceeds from the purchase of the accounts receivable to pay off the accounts payable due Obsidian Capital Company in the amount of $624 and the amount due shareholders and other related parties in the approximate amount of $300.

The Company was obligated to the stockholders and certain employees (that were formerly stockholders of subsidiary companies) under note payable agreements acquired as part of the acquisitions. In addition, the Company has entered into note payable agreements with other affiliated entities. The details of these notes payable are included in Note 8.

On December 17, 2002, Obsidian Leasing sold four coaches to DC Investments Leasing in exchange for DC Investments Leasing s satisfaction of the debt outstanding on such coaches. DC Investments Leasing paid this debt through a refinancing at terms that included a reduction in interest rates. In addition, DC Investments Leasing also acquired five additional coaches that were previously to be purchased by us thereby eliminating our existing purchase commitment for the coaches. DC Investments Leasing also entered into a management agreement with Pyramid under which all nine coaches described above will be leased by Pyramid.

In February and March 2004, the Company secured an additional financial commitment from Fair Holdings to provide, as needed, additional borrowings under a line of credit agreement from $8,000 to $15,000. The line bears interest at 10% and the line of credit arrangement expires on January 1, 2007 at which time the total principal and interest is due and payable. No late fees were charged on this loan.

In July 2004 the Fair Holdings line of credit with Danzer was amended to increase the total availability from $1,500 to $3,000. All other terms of the agreement will continue as stated in the original and amended agreement dated August 15, 2001 which includes interest at LIBOR plus 3.2%. No late fees have been assessed by Fair Holdings for this loan.

16. COMMITMENTS AND CONTINGENCIES

In connection with their dealers wholesale floor-plan financing of cargo trailers, the Company has entered into repurchase agreements with various lending institutions. Each repurchase commitment is on an individual unit basis with a term from the date it is financed by the lending institution through payment date by the dealer, generally not exceeding one year. Outstanding obligations are approximately $2,375 at October

31, 2004. Repurchase agreements with third party financing sources are ordinary and customary in the cargo trailer industry. The repurchase obligations are limited to the repurchase of the inventory, in like new condition, and only in the event a dealer is in default under its agreement with the finance company. The Company is not responsible for interest or any other carrying cost incurred by the dealer, and is not responsible for any required curtailment payments to be made by the dealer to the finance company based on the aging of the finance company receivable. The dealer cannot initiate the repurchase obligation and has no right to return the product to the Company. The Company receives credit approval from the third party finance company prior to shipping the product and generally receives payment with in a few days. The Company s repurchase activity under these agreements has historically been infrequent and the losses incurred have been minimal. The loss is limited to the difference between the repurchase amount and the subsequent resale of the inventory. Losses incurred under such arrangements have not been significant and the estimated liability for losses on contracts outstanding at October 31, 2004 is not material.

In the normal course of business, the Company is liable for contract completion and product performance. In the opinion of management, such obligations will not significantly affect the Company s financial position or results of operations.

Subsequent to October 31, 2004, U.S. Rubber entered into a number of agreements relating to the installation of a cryogenic system. These commitments total approximately $253. Minimum future payments under the commitments are as follows:

Year Ending October 31,	
2005	$ 76
2006	29
2007	29
2008	29
2009 and thereafter	90
	$ 253

17. SUBSEQUENT EVENTS

In November 2004, Obsidian Leasing sold two of its coaches. Total proceeds associated with the sale of these coaches were approximately $220 of which $209 was used to pay off commitments associated with the coaches. There was no material gain or loss recorded on the sale. The Company is currently in the process of selling an additional three coaches.

17. SUBSEQUENT EVENTS, CONTINUED

In December 2004 Pyramid and its parent, Obsidian Enterprises, and other affiliated companies and members filed suit against the former owners of Pyramid for violation of the terms of its non-compete agreement. The lawsuit was filed against various individuals and operating entities that are directly competing with the Company and is seeking punitive and compensating damages. While the ultimate result of the lawsuit is unknown at this time, management believes that the outcome will be favorable.

Effective December 28, 2004, the credit agreement for the line of credit with Classic was temporarily amended to increase the borrowing base until April 1, 2005 to the following: The borrowing base is equal to 85% of eligible accounts receivable plus the lesser of 75% of all outstanding line of credit advances, $750, or the sum of 60% of finished goods and raw material eligible inventory plus the lesser of 60% of work-in-process eligible inventory or $90 minus inventory reserves. On April 1, 2005, the borrowing base will revert to the original agreement.

18. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)
(dollars in thousands, except per share amounts)

YEAR ENDED OCTOBER 31, 2004

	First Qtr. Ended 1/31/04	Second Qtr. Ended 4/30/04	Third Qtr. Ended 7/31/04	Fourth Qtr. Ended 10/31/04
Net sales	$ 12,046	$ 16,292	$ 18,227	$ 17,795
Gross profit	1,067	1,103	2,809	1,577
Loss from continuing operations	(2,218)	(2,890)	(686)	(2,167)
Loss from continuing operations per basic common and common equivalent share	(3.32)	(1.00)	(0.13)	(0.66)

YEAR ENDED OCTOBER 31, 2003

	First Qtr. Ended 1/31/03	Second Qtr. Ended 4/30/03	Third Qtr. Ended 7/31/03	Fourth Qtr. Ended 10/31/03
Net sales	$ 10,899	$ 15,107	$ 16,795	$ 16,494
Gross profit	1,160	1,791	2,405	2,203***
Loss from continuing operations	(1,517)	(909)	(307)	(1,091)***
Loss from continuing operations per basic common and common equivalent share	(2.25)	(1.26)	(0.14)	(1.52)

OBSIDIAN ENTERPRISES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(all amounts in thousands, except per share and share data)

18. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED), CONTINUED

YEAR ENDED OCTOBER 31, 2002

	First Qtr. Ended 1/31/02	Second Qtr. Ended 4/30/02	Third Qtr. Ended 7/31/02	Fourth Qtr. Ended 10/31/02
Net sales	$ 11,466	$ 15,598	$ 15,239	$ 14,971
Gross profit	1,518	2,625	2,839	2,653
Income (loss) from continuing operations	(1,207)	(570)	471	(1,531)**

	First Qtr. Ended 1/31/02	Second Qtr. Ended 4/30/02	Third Qtr. Ended 7/31/02	Fourth Qtr. Ended 10/31/02
Income (loss) from continuing operations per basic common and common equivalent share	(1.68)	(0.79)	0.65	(2.13)

**The fourth quarter includes the charge for the impairment of goodwill of $720 for October 31, 2002.

***The fourth quarter includes a charge related to inventory at United of $500

SCHEDULE II VALUATION AND QUALIFYING OF ACCOUNTS

Year Ended October 31, 2004
(in thousands)

Column A Description	Column B Balance at Beginning of Period	Column C---Additions (1) Charged to Costs and Expenses	Column C---Additions (2) Charged to Other Accounts Describe	Column D Deductions Describe	Column E Balance at End of Period
Allowance for doubtful accounts	$ 496	$ 287	$ ---	$ 40(1)	$ 743
Inventory valuation allowances	$ 321	$ ---	$ ---	$ 99(2)	$ 222
Deferred tax valuation reserve	$ 1,971	$ 2,866	$ ---	$ ---	$ 4,837

Year Ended October 31, 2003
(in thousands)

Column A Description	Column B Balance at Beginning of Period	Column C---Additions (1) Charged to Costs and Expenses	Column C---Additions (2) Charged to Other Accounts Describe	Column D Deductions Describe	Column E Balance at End of Period
Allowance for doubtful accounts	$ 495	$ 20	$ ---	$ 19(1)	$ 496

(all amounts in thousands, except per share and share data)

		Column C---Additions			
Inventory valuation allowances	$ 466	$ ---	$ ---	$ 145(2)	$ 321
Deferred tax valuation reserve	$ 1,171	$ 1,027	$ 218(3)	$ 445(4)	$ 1,971

(1) Recovery of amounts previously reserved.
(2) Use of inventory previously reserved.
(3) Additional valuation reserve recorded related to adjustment to net operating loss carryforwards. No income or loss recorded in the financial statements.
(4) Reduction from the sale of Champion to a related party. No income or loss recorded due to involvement of related parties.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURES.

None

ITEM 9A. CONTROLS AND PROCEDURES.

The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in the reports we file pursuant to the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. The Company s management recognizes that, because the design of any system of controls is based in part upon certain assumptions about the likelihood of future events and also is subject to other inherent limitations, disclosure controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance of achieving the desired objectives.

Under the supervision and with the participation of the Company s management, including the Company s Chief Executive Officer and Chief Financial Officer, the Company has evaluated the effectiveness of the Company s disclosure controls and procedures as of October 31, 2004. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, for the reasons more fully set forth below, the Company s disclosure controls and procedures were not effective on October 31, 2004 in providing reasonable assurance that information required to be disclosed in the reports we file pursuant to the Securities Exchange Act of 1934 was recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

More specifically, the Company s management has concluded that (i) additional accounting personnel were needed both at the parent company level and at certain subsidiaries at October 31, 2004 to ensure that certain disclosure controls and procedures were operating effectively; (ii) greater segregation of duties was needed in the accounting functions; and (iii) certain procedures should be documented to ensure that personnel turnover does not result in a failure of those procedures. In fiscal 2004 the Company hired two additional employees to join the accounting staff and is evaluating how best to utilize the time of these new employees. The Company will continue to evaluate the need for additional staff at the parent and subsidiary levels, but given the size and location of the Company s subsidiaries the Company believes it will continue to face challenges in attracting and retaining qualified personnel. Additionally, the Company is also in the process of evaluating ways in which the impact of personnel turnover on the implementation of disclosure controls and procedures can be reduced. Finally, as discussed below, the Company believes that the implementation of its new accounting system will enhance the segregation of duties of accounting personnel without the necessity of adding personnel.

In fiscal 2004, the Company implemented an enterprise wide, integrated accounting system that replaced the separate accounting systems previously maintained by the several subsidiaries and since that date has implemented an enhanced segregation of duties of various accounting personnel. There have been no other significant changes in the Company s internal controls or in other factors that could significantly affect internal controls subsequent to the date of the October 31, 2004 evaluation.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

The following table sets forth information with respect to all directors and executive officers of the Company, including their ages, present principal occupations, other business experience during the last five years.

Name	Age	Position	Director Since
Timothy S. Durham	42	Chief Executive Officer and Chairman of the Board	2001
Terry G. Whitesell	65	President, Chief Operating Officer and Director	2001
Jeffrey W. Osler	36	Executive Vice President, Secretary, Treasurer and Director	2001
D. Bruce Johnston+	54	Director	2004
John A. Schmit*+	37	Director	2001
D. Scott McKain*	50	Vice Chairman and Director	2001
Daniel S. Laikin+	42	Director	2001
Rick D. Snow	41	Executive Vice President and Chief Financial Officer	N/A
Anthony P. Schlichte	49	Executive Vice President of Corporate Finance	N/A

*Members of the Compensation Committee
+Members of the Audit Committee

Mr. Durham has served as the Chief Executive Officer and Chairman of the Board and as a director of the Company since June 2001. He has served as a Managing Member and Chief Executive Officer of Obsidian Capital Company LLC, which is the general partner of Obsidian Capital Partners, a major shareholder of the Company since April 2000. Beginning in 1998, Mr. Durham founded and maintained a controlling interest in several investment funds, including Durham Capital Corporation, Durham Hitchcock Whitesell and Company LLC, and Durham Whitesell & Associates LLC. From 1991 to 1998, Mr. Durham served in various capacities at Carpenter Industries, Inc., a school bus manufacturer, including as Vice Chairman, President and Chief Executive Officer. Mr. Durham also serves as a director of National Lampoon, Inc. Mr. Durham is Mr. Osler s brother-in-law.

Mr. Whitesell has served as the President and Chief Operating Officer and as a director of the Company since June 2001. Prior to that time he co-founded several entities with Mr. Durham, including Obsidian Capital Company, LLC, Durham Hitchcock Whitesell and Company LLC and Durham Whitesell & Associates LLC. Mr. Whitesell also is a Managing Member of Obsidian Capital Company LLC. From April 1992 until September 1998, Mr. Whitesell served as Executive Vice President of Carpenter Industries, Inc., which manufactured school buses.

Mr. Osler has served as the Executive Vice President, Secretary and Treasurer and as a director of the Company since June 2001. He also is a Managing Member of Obsidian Capital Company LLC and has served as Senior Vice President at Durham Whitesell & Associates LLC and Durham Capital Corporation since September 1998. Prior to that time, Mr. Osler served as the General Manager of Hilton Head National Golf Club. Mr. Osler is Mr. Durham s brother-in-law.

Mr. Johnston has served as a director of the Company since May 2004, when he was appointed by the Board to fill the vacancy created by the resignation of a prior director. Mr. Johnston currently provides consulting services through executive workshops across the nation. He had

served as President and Chief Executive Officer of Gartmore Global Investments, the asset management fund subsidiary of Nationwide Mutual Insurance Company from May 2002 to January 2004. From March 1998 to May 2002, he had served as Senior Vice President of Conseco Capital Management.

Mr. Schmit has been a director since July 2001. Since November 2004, Mr. Schmit has worked to form an investment fund. From 1997 through November 2004 he served as Vice President Investments at Renaissance Capital Group, Inc. Prior to joining Renaissance Capital Group, Mr. Schmit practiced law with the law firm of Gibson, Ochsner & Adkins in Amarillo, Texas from September 1992 to September 1994. Between August 1994 and May 1996, Mr. Schmit attended Georgetown University where he earned his L.L.M. in International and Comparative Law.

Mr. McKain has been a director of the Company since September 2001. He has served as the Chairman of McKain Performance Group since 1981. Mr. McKain also has been the Vice Chairman of Durham Capital Corporation since 1999. From 1983 to 1998, Mr. McKain was a broadcast journalist and television commentator. Mr. McKain has also authored several books and is a keynote speaker who presents high content workshops across the nation.

Mr. Laikin has served as a director of the Company since September 2001. Mr. Laikin is Chief Operating Officer and a director of National Lampoon, Inc., the owner of the National Lampoon trademark and engaged in the entertainment business. He has been a Managing Member of Fourleaf Management LLC, a management company of an investment fund that invests in technology related entities, since 1999. Mr. Laikin served as the Chairman of the Board of Biltmore Homes from 1993 to 1998.

Mr. Snow was named Executive Vice President and Chief Financial Officer in April 2003. He continues to serve as Chief Financial Officer for Fair Finance, Inc., a company for which Mr. Durham, the Company s Chairman and Chief Executive Officer, also serves as Chief Executive Officer. Prior to joining Fair Finance, Inc., in 2002, Mr. Snow had served as Senior Manager of Brockman, Coats, Gedelian & Co., a regional accounting firm from 1991 to 2002. Prior to joining Brockman, Coats, Gedelian & Co. in 1991, he was an accountant with Grant Thornton LLP.

Mr. Schlichte has served as Executive Vice President of Corporate Finance since April 2003. Previously he held vice president and senior lending officer positions at First Indiana Bank from 1981 to 2003.

AUDIT COMMITTEE FINANCIAL EXPERT

The Company s Board of Directors has determined that the three members of the Audit Committee, Daniel S. Laikin, D. Bruce Johnston, and John A. Schmit, each qualify as an audit committee financial expert as defined by Item 401(h) of Regulation S-K adopted pursuant to the Securities Exchange Act of 1934, as amended. Mr. Schmit has a bachelors degree in Finance and seven years of experience in reading, interpreting and analyzing financial statements in his role as Vice President, Investments for RENN Capital Group, Inc., a registered Investment Adviser. Mr. Laikin and Mr. Johnston also have extensive business experience that has involved the review of financial statements as more fully described in the above biographical information. Messrs. Johnston and Schmit also qualify as independent as that term is used in Item 7(d)(3)(iv) of Schedule 14A of the Securities Exchange Act of 1934, as amended.

CODE OF ETHICS

The Company has adopted a Code of Ethics for Chief Executive Officer and Senior Financial Officers (Code of Ethics), which applies to the Company s principal executive officer and to its principal financial and accounting officers. A copy of the Code of Ethics is attached as Exhibit 14 to this Annual Report on Form 10-K.

SECTION 16(A) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Compliance with Section 16(a) of the Securities Exchange Act of 1934 requires the Company s directors, executive officers, and persons who own more than ten percent of the Company s Common Stock (10% Shareholders) to file reports of ownership and reports of changes in ownership of the Company s Common Stock with the Securities Exchange Commission (SEC). Officers, Directors and 10% Shareholders are required by SEC regulation to furnish the Company with copies of all forms they file under Section 16 (a). Based solely on its review of the copies of such forms received by it with respect to its fiscal year ended October 31, 2004, and written representations from certain reporting persons that no other reports were required to be made by those persons, the Company believes that, except as disclosed below, its officers, directors and 10% Shareholders have complied with all Section 16(a) requirements for the fiscal year ended October 31, 2004.

Timothy S. Durham, the Company's Chief Executive Officer, was late in filing two Form 4s to report his acquisition of additional partnership

shares of Obsidian Capital Partners, which increased his pecuniary interest in the common shares of the Company held by Obsidian Capital Partners. Mr. Durham did, however, previously report that all holdings of the Company's common shares held by Obsidian Capital Partners were indirectly held by him.

ITEM 11. EXECUTIVE COMPENSATION.

SUMMARY COMPENSATION TABLE

The following table sets forth certain information concerning the compensation paid or accrued by the Company for services rendered during the Company s past three fiscal years ended October 31 by the Chief Executive Officer and each of the Company s other most highly compensated executive officers whose total annual compensation for fiscal 2004, based on salary and bonus earned during fiscal 2004, exceeded $100,000 (the Named Executive Officers). (No other executive officers of the Company received a salary and bonus for fiscal 2004 in excess of $100,000 so as to require their inclusion in the table.)

Annual Compensation

Name and Principal Position	Year	Salary	All Other Compensation
Timothy S. Durham, Chief Executive Officer	2004	$185,000	$9,600[1]
	2003	$ 75,000	$9,600[1]
	2002	$ 75,000	$9,600[1]
Terry G. Whitesell, President, Chief Operating Officer	2004	$185,000	$9,600[1]
	2003	$ 65,000	$9,600[1]
	2002	$ 65,000	$9,600[1]
Jeffrey W. Osler, Executive Vice President, Secretary, Treasurer	2004	$125,000	$9,600[1]
	2003	$ 55,000	$9,600[1]
	2002	$ 55,000	$9,600[1]

[1] Other compensation is a total annual car allowance.

OPTION/SAR GRANTS IN LAST FISCAL YEAR

No grants were made to the Company s Chief Executive Officer or other Named Executive Officers during fiscal 2004 pursuant to the Company s 1999 Stock Option Plan or the Company s 2002 Long Term Incentive Plan.

AGGREGATED OPTION/SAR EXERCISES IN LAST FISCAL YEAR AND FISCAL YEAR-END OPTION/SAR VALUES

No options have been granted during fiscal 2004 to the Company s Chief Executive Officer or other Named Executive Officers.

LONG-TERM INCENTIVE PLANS-AWARDS IN LAST FISCAL YEAR

No awards were made in fiscal 2004 to the Chief Executive Officers of other Named Executive Officers under any long-term incentive plan.

COMPENSATION OF DIRECTORS

Directors who are not employees of the Company are entitled to a board meeting attendance fee of $750, plus reimbursement of expenses for each meeting attended.

EMPLOYMENT AND CHANGE OF CONTROL AGREEMENTS

The Company does not have an employment agreement with its Chief Executive Officer or other Named Executive Officers.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

None.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

The following table sets forth information with respect to beneficial ownership of common stock as of January 1, 2005, by (i) all persons known to the Company to be the beneficial owner of five percent or more of the common stock, (ii) each director of the Company, (iii) the Chief Executive Officer and each of the Named Executive Officers; and (iv) all Company directors and executive officers as a group. This table does not include shares of common stock that may be purchased pursuant to options not exercisable within 60 days of the record date. All persons listed have sole voting and investment power with respect to their shares unless otherwise indicated.

Common Stock

Name and Address of Beneficial Owner	Number of Shares Beneficially Owned	Percentage of Shares Beneficially Owned
Executive Officers and Directors:		
Timothy S. Durham[1]	2,322,880	74.7%
D. Scott McKain	16,202	*
Jeffrey W. Osler[2]	1,824,036	58.7%
Terry G. Whitesell[3]	1,945,751	62.6%
John A. Schmit	---	---
Daniel S. Laikin	---	---
D. Bruce Johnston	---	---
All current officers and directors as a group (9 persons)	2,647,826	85.2%
Other 5% Owners:		
Fair Holdings[4]	241,039	7.8%
Huntington Capital Investment Company[5]	154,483	5.0%
Obsidian Capital Partners[6]	1,807,492	58.1%
CEDE & Co.[7]	279,703	9.0%

*less than one percent

(1) Includes 146,762 shares of common stock directly owned by Mr. Durham; 41,767 shares held by Diamond Investments, LLC, for which Mr. Durham serves as Managing Member and for which shares Mr. Durham may be deemed to share voting and dispositive power; 1,807,492 shares of common stock over which Mr. Durham shares voting and dispositive power and that may be deemed to be beneficially owned by Mr. Durham due to his position as a managing member of Obsidian Capital Company, LLC, which is the general partner of Obsidian Capital Partners, which directly owns such shares; 241,039 shares of common stock over which Mr. Durham shares voting and dispositive power and that may be deemed to be beneficially owned by Mr. Durham due to his position as an executive officer and shareholder of Fair Holdings which directly owns such shares; 42,639 shares held by FIB Firsttrust, for which Mr. Durham serves as Trustee and for which shares Mr. Durham may be deemed to share voting and dispositive power; 42,639 shares held by Firsttrust Indiana,

for which Mr. Durham serves as Trustee and for which shares Mr. Durham may be deemed to share voting and dispositive power; and 543 shares of common stock over which Mr. Durham shares voting and dispositive power and that may be deemed to be beneficially owned by Mr. Durham due to his position as a managing member of Durham Whitesell and Associates, LLC, which directly owns such shares. The address of Mr. Durham is 111 Monument Circle, Suite 4800, Indianapolis, Indiana 46204.

(2) Includes 16,544 shares of common stock directly owned by Mr. Osler; and 1,807,492 shares of common stock over which Mr. Osler shares voting and dispositive power and that may be deemed to be beneficially owned by Mr. Osler due to his position as a managing member of Obsidian Capital Company, LLC, which is the general partner of Obsidian Capital Partners, which directly owns such shares. The address of Mr. Osler is 111 Monument Circle, Suite 4800, Indianapolis, Indiana 46204.

(3) Includes 137,717 shares of common stock directly owned by Mr. Whitesell; 1,807,492 shares of common stock over which Mr. Whitesell shares voting and dispositive power and that may be deemed to be beneficially owned by Mr. Whitesell due to his position as a managing member of Obsidian Capital Company, LLC, which is the general partner of Obsidian Capital Partners, which directly owns such shares; and 543 shares of common stock over which Mr. Whitesell shares voting and dispositive power and that may be deemed to be beneficially owned by Mr. Whitesell due to his position as a managing member of Durham Whitesell and Associates, LLC, which directly owns such shares. The address of Mr. Whitesell is 111 Monument Circle, Suite 4800, Indianapolis, Indiana 46204.

(4) Consists of 241,039 shares of common stock directly owned by Fair Holdings. The address of Fair Holdings is 111 Monument Circle, Suite 4800, Indianapolis, Indiana 46204.

(5) Consists of 154,483 shares of common stock directly owned by Huntington Capital Investment Company. The address of Huntington Capital Investment Company is 41 South High Street, 9th Floor, Columbus, Ohio 43215.

(6) Consists of 1,807,492 shares of common stock directly owned by Obsidian Capital Partners. Voting and dispositive power over the shares may be deemed to be held by Obsidian Capital Partners, Obsidian Capital Company, LLC and the managing members of Obsidian Capital Company LLC, which include Messrs. Durham, Whitesell and Osler. The address of Obsidian Capital Partners is 111 Monument Circle, Suite 4800, Indianapolis, Indiana 46204.

(7) Consists of 279,703 shares of common stock directly owned by CEDE & Co. The address of CEDE & Co. is Box 222 Bowling Green Station, New York , NY 10004.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

All dollar amounts in this Item 13 are in thousands (except for share and per share information).

The Company subleases its headquarters space from Fair Holdings under a sublease with a monthly rental payment of $4,498.

DW Trailer, a company owned by Messrs. Durham and Whitesell, has leased a forklift to Danzer under a 38 month lease at $1 per month.

On March 28, 2003, Fair Holdings, a company controlled by Mr. Durham, acquired the line of credit and term debt due to the senior lender of Danzer in the amount of $1,488 under an assignment and assumption agreement. The maturity date of the line of credit included in the assignment and assumption agreement was extended to April 2006, maximum borrowings under the line of credit were increased from $1,000 to $1,500, and the debt covenants required by the senior lender were waived through the end of the term. In July 2004 the Fair Holdings line of credit with Danzer was amended to increase the total availability from $1,500 to $3,000. All other terms of the agreement will continue as stated in the original and amended agreement dated August 15, 2001 which includes interest at LIBOR plus 3.2%. No late fees have been assessed by Fair Holdings for this loan.

In February and March, 2004, Obsidian Enterprises secured an additional financial commitment from Fair Holdings to provide, as needed, additional borrowings under a line of credit agreement from $8,000 to $15,000. The line of credit arrangement expires on January 1, 2007 at which time the total principal and interest is due and payable. No late fees were incurred or charged. Fair Holdings is controlled by Mr. Durham.

The following summarizes the current related party loans between the Company, Fair Holdings and DC Investments:

	Debt Outstanding at October 31, 2004
Obsidian Enterprises	
Line of credit issued by Fair Holdings, maximum borrowing equal to $15,000, interest payable monthly at 10%, due January 2007, collateralized by all assets of Obsidian Enterprises and personally guaranteed by certain officers	$10,815
Note payable to Fair Holdings, interest payable monthly at 15%, balloon payment due March 2007, personally guaranteed by certain officers	$ 934
Danzer	
Line of credit issued by Fair Holdings, maximum borrowing equal to $3,000, interest payable monthly at the LIBOR Daily Floating Rate plus 3.2% (5.187% at October 31, 2004), due April 2006. Collateralized by substantially all assets of Danzer and guaranteed by Obsidian Enterprises	$ 2,253
Note payable to Fair Holdings, requires monthly principal installments of $6, interest accrues at the LIBOR Daily Floating Rate plus 3.2% (5.187% at October 31, 2004), due April, 2006. Collateralized by substantially all assets of Danzer and guaranteed by Obsidian Enterprises	$ 894
Pyramid, DW Leasing, DC Investments Leasing and Obsidian Leasing	
Notes payable to Fair Holdings, repayable in monthly installments of interest ranging from 10% to 14% through October 2012 and applicable balloon payments through December 2012	$ 4,669
US Rubber	
Note payable to DC Investments, interest payable monthly at 15%, balloon payment due March 2007, subordinate to bank debt	$ 700

The notes to DC Investments and Fair Holdings did not incur any additional fees including late fees. In addition to the notes the Company has an account payable to DC Investments and Fair Holdings totaling $1,181.

Management believes that the transactions described in this Item were on terms no less favorable to the Company and its subsidiaries than would have been the case for transactions with unrelated third parties. Please see Note 15 to the Notes to Consolidated Financial Statements for additional information regarding related party transactions which is incorporated by reference into this Item 13.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

McGladrey & Pullen, LLP (McGladrey & Pullen) served as the Company s independent auditors for 2004 and 2003. The services performed by McGladrey & Pullen in this capacity included conducting an examination in accordance with generally accepted auditing standards of, and expressing an opinion on, the Company s consolidated financial statements. The Board of Directors has selected McGladrey & Pullen as the independent public accountants for the year ending October 31, 2005.

Audit Fees

McGladrey & Pullen s aggregate fees billed for professional services rendered in connection with the audit and review of Forms 10-Q and all other SEC regulatory filings were $ 373, 217 for the 2004 fiscal year, and $217,850 for the 2003 fiscal year. The Company has paid and is current on all billed fees.

Audit-Related Fees

McGladrey & Pullen s fees for audit related services rendered in connection with the audit of a subsidiary s defined contribution plan were $16,662 for the 2004 fiscal year and $7,035 for the 2003 fiscal year. The Company has paid and is current on all billed fees.

Tax Fees

McGladrey & Pullen did not render any tax compliance advice or planning services for the 2004 and 2003 fiscal years.

The Company has paid and is current on all billed fees.

All Other Fees

McGladrey & Pullen did not render any management advisory services for the 2004 and 2003 fiscal years.

Audit Committee

The Company s Audit Committee pre-approves 100% of audit and audit related services with the exception of tax, benefit and other management advisory services.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) The following documents are filed as part of this Form 10-K:

1. Consolidated Financial Statements of Obsidian Enterprises, Incorporated and Subsidiaries:

   Independent Auditor s Report

   Consolidated Balance Sheets October 31, 2004 and 2003

   Consolidated Statements of Operations Years ended October 31, 2004, 2003, and 2002

   Consolidated Statements of Stockholders Equity (Deficit) and Comprehensive Loss Years ended October 31, 2004, 2003, and 2002

   Consolidated Statements of Cash Flows Years ended October 31, 2004, 2003, and 2002

   Notes to Consolidated Financial Statements.

2. Consolidated Financials Statement Schedule of Obsidian Enterprises, Incorporated and Subsidiaries:

   Schedule II Valuation and Qualifying of Accounts Years ended October 31, 2004, 2003, and 2002

All other schedules are omitted because they are not applicable or because the required information is included in the consolidated financial statements or the notes thereto.

(b) Exhibits:

See Exhibit Index

(c) Additional Financial Statements:

The individual financial statements of the registrant s subsidiaries have been omitted since the registrant is primarily an operating company and all subsidiaries included in the consolidated financials statements are wholly-owned subsidiaries.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the Registrant caused this report to be signed on its behalf, by the undersigned, thereunto duly authorized.

Dated: February 14, 2005

OBSIDIAN ENTERPRISES, INC.

By /s/ Timothy S. Durham

Timothy S. Durham
Chief Executive Officer

In accordance with the Exchange Act, this report was signed by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Dated: February 14, 2005

/s/ Timothy S. Durham

Timothy S. Durham
Chief Executive Officer (Principal Executive Officer)
and Chairman of the Board and Director

Dated: February 14, 2005

/s/ Rick D. Snow

Rick D. Snow, Executive Vice President/Chief Financial
Officer (Principal Financial and Accounting Officer)

Dated: February 14, 2005

/s/ Jeffrey W. Osler

Jeffrey W. Osler, Executive Vice President, Secretary
and Treasurer and Director

Dated: February 14, 2005

/s/ Terry G. Whitesell

Terry G. Whitesell, Director

Dated: February 14, 2005

/s/ D. Bruce Johnston

D. Bruce Johnston, III, Director

Dated: February 14, 2005

/s/ John A. Schmit

John A. Schmit, Director

Dated: February 14, 2005

/s/ D. Scott McKain

D. Scott McKain, Vice Chairman and Director

Dated: February 14, 2005

/s/ Daniel S. Laikin

Daniel S. Laikin, Director

EXHIBIT INDEX

Exhibit No.	Description	Incorporated by Reference/Attached
3.1	Amended Certificate of Incorporation	Incorporated by reference to Exhibit 3.1 to Amendment No. 1 to the Registration Statement on Form S-4 filed on December 17, 2003

3.2	Certificate of Designations, Preferences, Rights and Limitations of Series C Preferred Stock	Incorporated by reference to Exhibit 3.2 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
3.3	Amended Certificate of Designations, Preferences, Rights and Limitations of Series C Preferred Stock	Incorporated by reference to Exhibit 3.1 to Amendment No. 1 to the Registration Statement on Form S-4 filed on December 17, 2003
3.4	Certificate of Designations, Preferences, Rights and Limitations of Series D Preferred Stock	Incorporated by reference to Exhibit 3.4 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
3.5	Amended Certificate of Designations, Preferences, Rights and Limitations of Series D Preferred Stock	Incorporated by reference to Exhibit 3.4(b) to Amendment No. 1 to the Registration Statement on Form S-4 filed on December 17, 2003
3.6	Bylaws of the Registrant (Restated Effective as of September 27, 2002)	Incorporated by reference to Exhibit 3.3 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
4.1	Registration Rights Agreement, dated June 21, 2001	Incorporated by reference to Exhibit 4.1 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
4.2	Amendment and Joinder to Registration Rights Agreement, dated July 27, 2001	Incorporated by reference to Exhibit 4.2 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
4.3	8.00% Convertible Debenture Issued by Registrant on July 19, 2001 to HSBC Global Custody Nominee Due July 19, 2008	Incorporated by reference to Exhibit 2 to Schedule 13D filed September 20, 2001 by Russell Cleveland, Renaissance Capital Group, Inc.

Exhibit No.	Description	Incorporated by Reference/Attached
4.4	8.00% Convertible Debenture Issued by Registrant on July 19, 2001 to Renaissance US Growth & Income Trust PLC Due July 19, 2008	Incorporated by reference to Exhibit 3 to Schedule 13D filed September 20, 2001 by Russell Cleveland, Renaissance Capital Group, Inc.
4.5	Convertible Loan Agreement, dated July 19, 2001, Among Registrant, BFSUS Special Opportunities Trust PLC, Renaissance US Growth & Income Trust PLC and Renaissance Capital Group, Inc.	Incorporated by reference to Exhibit 4.5 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
10.1	2001 Long Term Incentive Plan*	Incorporated by reference to Appendix E to the Registrant's Proxy Statement filed on September 18, 2001
10.2	Management Agreement, dated June 16, 2001, between Pyramid, Inc. and D.W. Leasing	Incorporated by reference to Exhibit 10.10 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
10.3	Promissory Note, dated June 1, 2001, from Obsidian Capital Company, LLC to U.S. Rubber Reclaiming, Inc.	Incorporated by reference to Exhibit 10.11 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001

10.4	Purchase Agreement, dated June 5, 2001, between United Expressline, Inc., United Acquisition, Inc., J.J.M. Incorporated and the Shareholders of United Expressline, Inc. and J.J.M. Incorporated	Incorporated by reference to Exhibit 10.13 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
10.5	Promissory Note, dated July 27, 2001, from United Acquisition, Inc. to United Expressline, Inc.	Incorporated by reference to Exhibit 10.14 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
10.6	Credit Agreement, dated July 27, 2001, between United Acquisition, Inc. and First Indiana Bank	Incorporated by reference to Exhibit 10.15 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
10.7	Loan and Security Agreement, dated January 21, 2000, between Danzer Industries, Inc. and Banc of America Commercial Finance Corp.	Incorporated by reference to Exhibit 10.16 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
10.8	Subordinated Secured Promissory Note, dated December 29, 2000, from USRR Acquisition Corp. to SerVaas, Inc.	Incorporated by reference to Exhibit 10.19 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
10.9	Form of Installment Loan from Edgar County Bank & Trust Co. to DW Leasing Company, LLC, Related Documents and Schedule Identifying Material Details	Incorporated by reference to Exhibit 10.21 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001

Exhibit No.	**Description**	**Incorporated by Reference/Attached**
10.10	Loan Agreement, dated December 10, 1999, between Old National Bank and DW Leasing Company, LLC, and Related Documents	Incorporated by reference to Exhibit 10.22 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
10.11	Form of Promissory Note from DW Leasing Company, LLC to Star Financial Bank, Related Documents and Schedule Identifying Material Details	Incorporated by reference to Exhibit 10.24 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
10.12	Master Lease Agreement, dated May 17, 2000, between Old National Bank and DW Leasing Company, LLC, and Related Documents	Incorporated by reference to Exhibit 10.26 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
10.13	Loan Agreement, dated June 1, 2000, between DW Leasing Company LLC and Regions Bank and Security Agreement	Incorporated by reference to Exhibit 10.27 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
10.14	Business Loan Agreement (Asset Based), dated August 15, 2001, between Danzer Industries, Inc. and Bank of America, N.A.	Incorporated by reference to Exhibit 10.28 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
10.15	1999 Stock Option Plan*	Incorporated by reference to Exhibit 10.29 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2001
10.16		

	Assignment and Assumption Agreement, dated February 20, 2002, between DW Leasing, LLC and Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended April 30, 2002
10.17	Replacement Promissory Note, dated February 26, 2002, from Obsidian Enterprises, Inc. to Fair Holdings, Inc. in the principal amount of $700,000 due March 1, 2007	Incorporated by reference to Exhibit 10.35 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
10.18	Promissory Note from Obsidian Enterprises, Inc. in favor of Fair Holdings, Inc. in the principal amount of $570,000 due February 1, 2007	Incorporated by reference to Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended April 30, 2002
10.19	Subscription Agreement of Fair Holdings, Inc. for 186,324 shares of Series C Preferred Stock	Incorporated by reference to Exhibit 10.6 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended April 30, 2002
10.20	Subscription Agreement of Obsidian Capital Partners, LP for 402,906 shares of Series C Preferred Stock	Incorporated by reference to Exhibit 10.7 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended April 30, 2002

Exhibit No.	Description	Incorporated by Reference/Attached
10.21	Second Amendment to Credit Agreement, dated August 28, 2002, between United Expressline, Inc. and First Indiana Bank, N.A.	Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed for the Quarter Ended July 31, 2002
10.22	Promissory Note, dated January 17, 2002, from DW Leasing Company, LLC, to Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.40 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
10.23	Promissory Note, dated September 3, 2002, from Obsidian Enterprises, Inc., to Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.41 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
10.24	Promissory Note, dated January 9, 2002, from Obsidian Enterprises, Inc. to Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.42 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
10.25	Credit Agreement, dated October 31, 2002, between Obsidian Leasing Company, Inc. and Old National Bank, N.A. and Related Documents	Incorporated by reference to Exhibit 10.43 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
10.26	Stock Purchase Agreement, dated July 27, 2001, between Danzer Corporation and The Huntington Capital Investment Company	Incorporated by reference to Exhibit A to the Schedule 13G filed by The Huntington Capital Investment Company on August 6, 2001
10.27	Loan Agreement, dated September 24, 2002, between Edgar County Bank & Trust Co. and Obsidian Leasing Company, Inc.	Incorporated by reference to Exhibit 10.45 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
10.28	Term Promissory Note, dated September 26, 2002, from Obsidian Leasing Company, Inc. to Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.46 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002

10.29	Note Purchase Agreement, dated July 27, 2001, between United Acquisition, Inc. and The Huntington Capital Investment Company	Incorporated by reference to Exhibit 10.47 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
10.30	Limited Forbearance Agreement, dated October 14, 2002, among Danzer Industries, Inc., Obsidian Enterprises, Inc. and Bank of America, N.A.	Incorporated by reference to Exhibit 10.48 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
10.31	Revolving Credit, Term Loan and Security Agreement, dated October 25, 2002, between PNC Bank, N.A. and U.S. Rubber Reclaiming, Inc. and Related Documents	Incorporated by reference to Exhibit 10.49 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002

Exhibit No.	Description	Incorporated by Reference/Attached
10.32	Term Promissory Note, dated October 31, 2002, from DW Leasing Company, LLC to Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.50 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
10.33	Rental Agreement, dated October 1, 2002, between DW Trailer, LLC and Danzer Industries, Inc.	Incorporated by reference to Exhibit 10.51 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
10.34	Commercial Equipment Lease Agreement, dated August 1, 2002, between Fair Holdings, Inc. and Danzer Industries, Inc.	Incorporated by reference to Exhibit 10.52 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
10.35	Commercial Equipment Lease Agreement, dated August 1, 2002, between Fair Holdings, Inc. and Obsidian Enterprises, Inc.	Incorporated by reference to Exhibit 10.53 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2002
10.36	Promissory Term Note, dated November 18, 2002, from Obsidian Leasing Company, Inc. to Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended January 31, 2003
10.37	Third Amendment to Credit Agreement, dated December 26, 2002, between United Expressline, Inc. and First Indiana Bank, N.A.	Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended January 31, 2003
10.38	Credit Agreement, dated December 18, 2002, between DC Investments Leasing, LLC and First Indiana Bank, N.A. and Related Documents	Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended January 31, 2003
10.39	Term Promissory Note, dated January 3, 2003, from Obsidian Leasing, Inc. to Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended January 31, 2003
10.40	Stock Purchase Warrant, dated January 24, 2003, issued by Obsidian Enterprises, Inc. to Frost National Bank, Custodian, FBO Renaissance US Growth Investment Trust PLC Trust No. WOO740100	Incorporated by reference to Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended January 31, 2003
10.41		

	Stock Purchase Warrant, dated January 24, 2003, issued by Obsidian Enterprises, Inc., to HSBC Global Custody Nominee (UK) Limited, FBO BFS US Special Opportunities Trust PLC	Incorporated by reference to Exhibit 10.6 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended January 31, 2003

Exhibit No.	Description	Incorporated by Reference/Attached
10.42	Second Limited Forbearance Agreement, dated February 28, 2003, between Danzer Industries, Inc. and Obsidian Enterprises, Inc.	Incorporated by reference to Exhibit 10.7 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended January 31, 2003
10.43	Form of Letter Amending Stock Options and Schedule Identifying Material Details*	Incorporated by reference to Exhibit 10.8 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended January 31, 2003
10.44	First Amendment to Promissory Note, dated January 9, 2003	Incorporated by reference to Exhibit 10.9 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended January 31, 2003
10.45	Sublease, effective as of January 1, 2003, between Fair Holdings, Inc. and Obsidian Enterprises, Inc.	Incorporated by reference to Exhibit 10.10 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended January 31, 2003
10.46	Commercial Equipment Lease Agreement, commencing November 20, 2002, between Fair Holdings, Inc. and United Expressline, Inc.	Incorporated by reference to Exhibit 10.11 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended January 31, 2003
10.47	Assignment Agreement, dated May 12, 2003, between Obsidian Enterprises, Inc. and Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended April 30, 2003
10.48	Assignment of Note and Other Loan Documents, dated March 28, 2003, between Bank of America, N.A. and Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended April 30, 2003
10.49	First Amendment to Business Loan Agreement and Promissory Note (Line of Credit), dated March 28, 2003, between Danzer Industries, Inc. and Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended April 30, 2003
10.50	Second Amendment to Promissory Note (Line of Credit), dated April 1, 2003, between Obsidian Enterprises, Inc. and Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended April 30, 2003
10.51	Employment Agreement, dated April 30, 2003, between Obsidian Enterprises, Inc. and Rick D. Snow*	Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended July 31, 2003

Exhibit No.	Description	Incorporated by Reference/Attached

10.52	Third Amendment to Promissory Note (Line of Credit), dated February 2, 2004, between Obsidian Enterprises, Inc. and Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.70 on the Registrant's Annual Report on Form 10K for the Year Ended October 31, 2003
10.53	Term Promissory Note, dated September 19, 2003, from DC Investments Leasing, LLC to Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.71 on the Registrant's Annual Report on Form 10K for the Year Ended October 31, 2003
10.54	Promissory Note, dated August 31, 2003, from DC Investments, Inc. to Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.72 on the Registrant's Annual Report on Form 10K for the Year Ended October 31, 2003
10.55	Second Amendment to Revolver Promissory Note, dated September 31, 2003, between Danzer Industries, Inc. and Fair Holdings, Inc.	Incorporated by reference to Exhibit 10.73 on the Registrant's Annual Report on Form 10K for the Year Ended October 31, 2003
10.56	Stock Purchase Warrant, dated February 9, 2004, issued by Obsidian Enterprises, Inc. to HSBC Global Custody Nominee (UK) Limited, FBO BFS US Special Opportunities Trust PLC	Incorporated by reference to Exhibit 10.74 on the Registrant's Annual Report on Form 10K for the Year Ended October 31, 2003
10.57	Stock Purchase Warrant, dated February 9, 2004, issued by Obsidian Enterprises, Inc. to Frost National Bank, Custodian, FBO Renaissance US Growth Investment Trust PLC, Trust No. W00740100	Incorporated by reference to Exhibit 10.75 on the Registrant's Annual Report on Form 10K for the Year Ended October 31, 2003
10.58	Third Amendment to Revolver Promissory Note by and among Danzer Industries, Inc. and Fair Holdings, Inc., dated May 1, 2004	Incorporated by reference to Exhibit 10.1 on the Registrant's Quarterly Report on Form 10-Q for the Quarter Ended July 31, 2004
10.59	Credit Agreement, dated as of April 28, 2004, between Classic Manufacturing Acquisition Corp. and National City Bank of Indiana	Incorporated by reference to Exhibit 10.1 on the Registrant's Form 8-K dated May 14, 2004
10.60	Facility Lease for Pyramid Coach, Inc. with Fergusen Properties, dated November 16, 2004	Attached
10.61	Facility Lease for Classic Manufacturing, Inc. with Roost Leasing, dated April 27, 2004	Attached
10.62	Amended Credit Agreement, dated December 28, 2004, between Classic Manufacturing Acquisition Corp. and National City Bank of Indiana	Attached
10.63	Third Amendment to Revolver Promissory Note by and among Danzer Industries, Inc. and Fair Holdings, Inc., dated July 1, 2004	Attached
10.64	Second Amendment to Promissory Note by and among Obsidian Leasing Company, Inc. and Fair Holdings, Inc., dated August 31, 2004	Attached

Description

Exhibit No.		Incorporated by Reference/Attached
10.65	Second Amendment to Note Purchase Agreement between United Expresslines and The Huntington Capital Company	Attached
14	Code of Ethics for Chief Executive Officer and Senior Financial Officers	Incorporated by reference to Exhibit 14 to the Registrant's Annual Report on Form 10-K for the Year Ended October 31, 2004
21	List of Subsidiaries	Attached
31.1	Sarbanes-Oxley Act Section 302 Certification	Attached
31.2	Sarbanes-Oxley Act Section 302 Certification	Attached
32	Sarbanes-Oxley Act Section 906 Certification	Attached

*Indicates Exhibits that describe or evidence management contracts or compensatory plans or arrangements required to be filed as Exhibits to this Annual Report on Form 10-K.