AES CORP
Form 10-Q
November 04, 2011
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended September 30, 2011

or

¨ **TRANSITION REPORT 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)**

(703) 522-1315

Registrant s telephone number, including area code:

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 (§232.405 of this chapter) 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 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 ¨	Smaller reporting company ¨
		(Do not check if a smaller reporting company)	

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

The number of shares outstanding of Registrant s Common Stock, par value $0.01 per share, on October 28, 2011 was 767,548,237.

Table of Contents

THE AES CORPORATION

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2011

TABLE OF CONTENTS

Table of Contents

PART I: FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

THE AES CORPORATION

Condensed Consolidated Statements of Operations

(Unaudited)

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions, except per share amounts)			
Revenue:				
Regulated	$ 2,405	$ 2,244	$ 7,228	$ 6,642
Non-Regulated	1,976	1,746	5,889	5,135
Total revenue	4,381	3,990	13,117	11,777
Cost of Sales:				
Regulated	(1,743)	(1,638)	(5,435)	(4,918)
Non-Regulated	(1,618)	(1,385)	(4,663)	(3,958)
Total cost of sales	(3,361)	(3,023)	(10,098)	(8,876)
Gross margin	1,020	967	3,019	2,901
General and administrative expenses	(91)	(98)	(283)	(279)
Interest expense	(432)	(381)	(1,178)	(1,151)
Interest income	103	96	293	304
Other expense	(76)	(23)	(131)	(83)
Other income	58	17	108	94
Gain on sale of investments	-	-	7	-
Goodwill impairment	(17)	(18)	(17)	(18)
Asset impairment expense	(163)	(296)	(196)	(297)
Foreign currency transaction (losses) gains on net monetary position	(92)	103	(21)	(19)
Other non-operating expense	(82)	(2)	(82)	(7)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES AND EQUITY IN EARNINGS OF AFFILIATES	228	365	1,519	1,445
Income tax expense	(84)	(102)	(469)	(540)
Net equity in earnings of affiliates	6	26	12	174
INCOME FROM CONTINUING OPERATIONS	150	289	1,062	1,079
Income from operations of discontinued businesses, net of income tax (benefit) expense of $(31), $8, $(33) and $23, respectively	25	29	23	92
Gain from disposal of discontinued businesses, net of income tax expense of $0, $38, $0 and $38, respectively	-	79	-	57
NET INCOME	175	397	1,085	1,228
Noncontrolling interests:				
Less: Income from continuing operations attributable to noncontrolling interests	(269)	(248)	(766)	(725)
Less: Income from discontinued operations attributable to noncontrolling interests	(37)	(35)	(52)	(58)
Total net income attributable to noncontrolling interests	(306)	(283)	(818)	(783)

NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$	(131)	$	114	$	267	$	445
BASIC EARNINGS PER SHARE:								
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$	(0.15)	$	0.05	$	0.38	$	0.46
Discontinued operations attributable to The AES Corporation common stockholders, net of tax		(0.02)		0.09		(0.04)		0.12
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$	(0.17)	$	0.14	$	0.34	$	0.58
DILUTED EARNINGS PER SHARE:								
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$	(0.15)	$	0.05	$	0.38	$	0.46
Discontinued operations attributable to The AES Corporation common stockholders, net of tax		(0.02)		0.09		(0.04)		0.12
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$	(0.17)	$	0.14	$	0.34	$	0.58
AMOUNTS ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:								
Income (loss) from continuing operations, net of tax	$	(119)	$	41	$	296	$	354
Discontinued operations, net of tax		(12)		73		(29)		91
Net income (loss)	$	(131)	$	114	$	267	$	445

See Notes to Condensed Consolidated Financial Statements

Table of Contents

THE AES CORPORATION

Condensed Consolidated Balance Sheets

	September 30, 2011	December 31, 2010
	(in millions, except share and per share data)	
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 3,392	$ 2,550
Restricted cash	795	502
Short-term investments	1,053	1,718
Accounts receivable, net of allowance for doubtful accounts of $293 and $304, respectively	2,364	2,301
Inventory	668	561
Receivable from affiliates	28	27
Deferred income taxes current	278	305
Prepaid expenses	190	223
Other current assets	1,128	1,036
Current assets of discontinued and held for sale businesses	171	223
Total current assets	10,067	9,446
NONCURRENT ASSETS		
Property, Plant and Equipment:		
Land	1,029	1,126
Electric generation, distribution assets and other	29,945	27,929
Accumulated depreciation	(9,257)	(9,048)
Construction in progress	2,096	4,454
Property, plant and equipment, net	23,813	24,461
Other Assets:		
Investments in and advances to affiliates	1,401	1,320
Debt service reserves and other deposits	909	653
Goodwill	1,246	1,271
Other intangible assets, net of accumulated amortization of $153 and $157, respectively	493	511
Deferred income taxes noncurrent	585	646
Other	2,133	1,958
Noncurrent assets of discontinued and held for sale businesses	236	245
Total other assets	7,003	6,604
TOTAL ASSETS	$ 40,883	$ 40,511
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 1,792	$ 2,048
Accrued interest	395	257
Accrued and other liabilities	2,619	2,633
Non-recourse debt current, including $269 and $1,150, respectively, related to variable interest entities	2,163	2,567
Recourse debt current	11	463
Current liabilities of discontinued and held for sale businesses	261	97
Total current liabilities	7,241	8,065
LONG-TERM LIABILITIES		

Non-recourse debt noncurrent, including $2,168 and $2,199, respectively, related to variable interest entities	12,523	12,371
Recourse debt noncurrent	6,181	4,149
Deferred income taxes noncurrent	621	895
Pension and other post-retirement liabilities	1,310	1,511
Other long-term liabilities	2,978	2,812
Long-term liabilities of discontinued and held for sale businesses	112	235
Total long-term liabilities	23,725	21,973
Contingencies and Commitments (see Note 9)		
Cumulative preferred stock of subsidiary	60	60
EQUITY		
THE AES CORPORATION STOCKHOLDERS EQUITY		
Common stock ($0.01 par value, 1,200,000,000 shares authorized; 807,093,084 issued and 770,260,308 outstanding at September 30, 2011 and 804,894,313 issued and 787,607,240 outstanding at December 31, 2010	8	8
Additional paid-in capital	8,499	8,444
Retained earnings	887	620
Accumulated other comprehensive loss	(2,727)	(2,383)
Treasury stock, at cost (36,832,776 shares at September 30, 2011 and 17,287,073 shares at December 31, 2010, respectively)	(434)	(216)
Total The AES Corporation stockholders equity	6,233	6,473
NONCONTROLLING INTERESTS	3,624	3,940
Total equity	9,857	10,413
TOTAL LIABILITIES AND EQUITY	$ 40,883	$ 40,511

See Notes to Condensed Consolidated Financial Statements

2

Table of Contents

THE AES CORPORATION

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	Nine Months Ended September 30, 2011	2010
	(in millions)	
OPERATING ACTIVITIES:		
Net income	$ 1,085	$ 1,228
Adjustments to net income:		
Depreciation and amortization	947	876
Loss from sale of investments and impairment expense	321	350
(Gain) loss on disposal and impairment write-down discontinued operations	1	(102)
Provision for deferred taxes	(67)	31
Contingencies	36	75
Loss on the extinguishment of debt	52	9
Undistributed gain from sale of equity method investment	-	(118)
Other	65	(81)
Changes in operating assets and liabilities:		
Increase in accounts receivable	(185)	(136)
(Increase) decrease in inventory	(118)	9
Decrease in prepaid expenses and other current assets	62	194
Increase in other assets	(167)	(51)
Increase in accounts payable and accrued liabilities	200	4
Increase (decrease) in income taxes and other income tax payables, net	(151)	20
Increase in other liabilities	227	108
Net cash provided by operating activities	2,308	2,416
INVESTING ACTIVITIES:		
Capital expenditures	(1,832)	(1,528)
Acquisitions net of cash acquired	(158)	(237)
Proceeds from the sale of businesses	47	369
Proceeds from the sale of assets	89	11
Sale of short-term investments	4,191	4,583
Purchase of short-term investments	(3,632)	(4,540)
Increase in restricted cash	(164)	(82)
Increase in debt service reserves and other assets	(379)	(9)
Affiliate advances and equity investments	(91)	(77)
Proceeds from loan repayments	-	132
Proceeds from performance bond	199	-
Other investing	(4)	31
Net cash used in investing activities	(1,734)	(1,347)
FINANCING ACTIVITIES:		
Issuance of common stock	-	1,566
Borrowings under the revolving credit facilities, net	126	74
Issuance of recourse debt	2,050	-
Issuance of non-recourse debt	1,516	1,497
Repayments of recourse debt	(474)	(619)
Repayments of non-recourse debt	(1,489)	(1,441)
Payments for financing fees	(153)	(50)
Distributions to noncontrolling interests	(990)	(951)
Contributions from noncontrolling interests	6	-
Financed capital expenditures	(13)	(21)
Purchase of treasury stock	(225)	(15)

Other financing	(7)	(18)
Net cash provided by financing activities	347	22
Effect of exchange rate changes on cash	(79)	(21)
Total increase in cash and cash equivalents	842	1,070
Cash and cash equivalents, beginning	2,550	1,775
Cash and cash equivalents, ending	$ 3,392	$ 2,845
SUPPLEMENTAL DISCLOSURES:		
Cash payments for interest, net of amounts capitalized	$ 982	$ 1,003
Cash payments for income taxes, net of refunds	$ 647	$ 589

See Notes to Condensed Consolidated Financial Statements

Table of Contents

THE AES CORPORATION

Condensed Consolidated Statements of Changes in Equity

(Unaudited)

	THE AES CORPORATION STOCKHOLDERS						
	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Earnings (in millions)	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Consolidated Comprehensive Income
Balance at January 1, 2011	$ 8	$ (216)	$ 8,444	$ 620	$ (2,383)	$ 3,940	
Net income	-	-	-	267	-	818	$ 1,085
Change in fair value of available-for-sale securities, net of income tax	-	-	-	-	(3)	-	(3)
Foreign currency translation adjustment, net of income tax	-	-	-	-	(178)	(149)	(327)
Change in unfunded pensions obligation, net of income tax	-	-	-	-	4	8	12
Change in derivative fair value, including a reclassification to earnings, net of income tax	-	-	-	-	(167)	(26)	(193)
Other comprehensive income							(511)
Total comprehensive income							$ 574
Capital contributions from noncontrolling interests	-	-	-	-	-	9	
Distributions to noncontrolling interests	-	-	-	-	-	(990)	
Disposition of businesses	-	-	-	-	-	(2)	
Acquisition of treasury stock	-	(225)	-	-	-	-	
Issuance of common stock under benefit plans and exercise of stock options and warrants, net of income tax	-	7	20	-	-	-	
Stock compensation	-	-	16	-	-	-	
Net gain on sale of subsidiary shares to noncontrolling interests	-	-	19	-	-	-	
Sale of subsidiary shares to noncontrolling interests	-	-	-	-	-	16	
Balance at September 30, 2011	$ 8	$ (434)	$ 8,499	$ 887	$ (2,727)	$ 3,624	

	THE AES CORPORATION STOCKHOLDERS						
	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Earnings (in millions)	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Consolidated Comprehensive Income
Balance at January 1, 2010	$ 7	$ (126)	$ 6,868	$ 650	$ (2,724)	$ 4,205	
Net income	-	-	-	445	-	783	$ 1,228
Change in fair value of available-for-sale securities, net of income tax	-	-	-	-	(6)	-	(6)
Foreign currency translation adjustment, net of income tax	-	-	-	-	465	54	519
Change in unfunded pensions obligation, net of income tax	-	-	-	-	3	3	6
Change in derivative fair value, including a reclassification to earnings, net of income tax	-	-	-	-	(204)	(51)	(255)

Other comprehensive income													264
Total comprehensive income												$	1,492
Cumulative effect of consolidation of entities under variable interest entity accounting guidance		-		-		-		(47)		(38)		15	
Cumulative effect of deconsolidation of entities under variable interest entity accounting guidance		-		-		-		1		-		-	
Capital contributions from noncontrolling interests		-		-		-		-		-		30	
Distributions to noncontrolling interests		-		-		-		-		-		(1,068)	
Disposition of businesses		-		-		-		-		-		(78)	
Acquisition of treasury stock		-		(15)		-		-		-		-	
Issuance of common stock		1		-		1,566		-		-		-	
Issuance of common stock under benefit plans and exercise of stock options and warrants, net of income tax		-		9		10		-		-		-	
Stock compensation		-		-		18		-		-		-	
Changes in the carrying amount of redeemable stock of subsidiaries		-		-		-		7		-		-	
Balance at September 30, 2010	$	8	$	(132)	$	8,462	$	1,056	$	(2,504)	$	3,893	

See Notes to Condensed Consolidated Financial Statements

THE AES CORPORATION

Notes to Condensed Consolidated Financial Statements

For the Three and Nine Months Ended September 30, 2011 and 2010

1. FINANCIAL STATEMENT PRESENTATION

The prior period condensed consolidated financial statements in this Quarterly Report on Form 10-Q (Form 10-Q) have been reclassified to reflect the businesses held for sale and discontinued operations as discussed in Note 16 *Discontinued Operations and Held for Sale Businesses*.

On June 1, 2011, The AES Corporation filed a Current Report on Form 8-K (June 2011 Form 8-K) to recast previously filed financial statements and other information included in the Company s Form 10-K for the year ended December 31, 2010 (2010 Form 10-K) to reclassify certain businesses held for sale as discussed in Note 16 *Discontinued Operations and Held for Sale Businesses*. The updates to the 2010 Form 10-K were limited to the Company s Business Overview, Selected Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements and Notes contained in Items 1, 6, 7 and 8, respectively. All other information in the 2010 Form 10-K remains unchanged.

Consolidation

In this Quarterly Report the terms AES , the Company , us or we refer to the consolidated entity including its subsidiaries and affiliates. The term The AES Corporation , the Parent or the Parent Company refer only to the publicly-held holding company, The AES Corporation, excluding its subsidiaries and affiliates. Furthermore, variable interest entities (VIEs) in which the Company has a variable interest have been consolidated where the Company is the primary beneficiary. Investments in which the Company has the ability to exercise significant influence, but not control, are accounted for using the equity method of accounting. All intercompany transactions and balances have been eliminated in consolidation.

AES Thames, LLC (Thames), a 208 MW coal fired plant in Connecticut, filed petitions for bankruptcy protection under Chapter 11 in the U.S. Bankruptcy Court on February 1, 2011. Effective that date, the Company lost control of the business and is no longer able to exercise significant influence over its operating and financial policies. In accordance with the accounting guidance on consolidations, Thames was deconsolidated in February 2011 and is now accounted for as a cost method investment. At the time of deconsolidation, Thames had total assets and total liabilities of $158 million and $170 million, respectively. Subsequently, the Company paid $5 million in satisfaction of a pre-existing guarantee. A net gain of $7 million has been deferred pending the completion of the bankruptcy proceedings.

Interim Financial Presentation

The accompanying unaudited condensed consolidated financial statements and footnotes have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP), as contained in the Financial Accounting Standards Board (FASB) Accounting Standards Codification, for interim financial information and Article 10 of Regulation S-X issued by the U.S. Securities and Exchange Commission (SEC). Accordingly, they do not include all the information and footnotes required by U.S. GAAP for annual fiscal reporting periods. In the opinion of management, the interim financial information includes all adjustments of a normal recurring nature necessary for a fair presentation of the results of operations, financial position, changes in equity and cash flows. The results of operations for the three and nine months ended September 30, 2011 are not necessarily indicative of results that may be expected for the year ending December 31, 2011. The accompanying condensed consolidated financial statements are unaudited and should be read in conjunction with the 2010 audited consolidated financial statements and notes thereto, which are included in the June 2011 Form 8-K.

Table of Contents

Change in Estimate

On January 1, 2011, the Company changed its estimates related to depreciation of property, plant and equipment at its Brazilian concessionary utility and generation businesses. Based on recent information received from regulators, the depreciation rates and salvage values for its concession assets were adjusted on a prospective basis to reflect a remuneration basis, which equates to the reimbursement expected by the Company at the end of the respective concession periods. For the three months ended September 30, 2011, the impact to the condensed consolidated statement of operations was an increase in depreciation expense of $17 million and a decrease in net income attributable to The AES Corporation of $5 million, or $0.01 per share. For the nine months ended September 30, 2011, the impact to the condensed consolidated statement of operations was an increase in depreciation expense of $52 million and a decrease in net income attributable to The AES Corporation of $14 million, or $0.02 per share.

New Accounting Policies Adopted

Accounting Standards Update (ASU) No. 2009-13, Revenue Recognition (Topic 605), Multiple-Deliverable Revenue Arrangements

In October 2009, the FASB issued ASU No. 2009-13, which amended the accounting guidance related to revenue recognition. The amended guidance provides primarily two changes to the prior guidance for multiple-element revenue arrangements. The first eliminated the requirement that there be objective and reliable evidence of fair value for any undelivered items in order for a delivered item to be treated as a separate unit of accounting. The second required that the consideration from multiple-element revenue arrangements be allocated to all the deliverables based on their relative selling price at the inception of the arrangement. AES adopted the standard on January 1, 2011. AES elected prospective adoption and applied the revised guidance to all revenue arrangements entered into or materially modified after the date of adoption. The adoption of ASU No. 2009-13 did not have a material impact on the financial position and results of operations of AES and is not expected to have a material impact in future periods.

ASU No. 2010-28, Intangibles Goodwill and Other (Topic 350), When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts

In December 2010, the FASB issued ASU No. 2010-28, which amended the accounting guidance related to goodwill. The amendment modified Step One of the goodwill impairment test for reporting units with zero or negative carrying amounts. For those reporting units, an entity is required to perform Step Two of the goodwill impairment test if it is more likely than not that a goodwill impairment exists, eliminating an entity s ability to assert that a reporting unit is not required to perform Step Two because the carrying amount of the reporting unit is zero or negative, despite the existence of qualitative factors that indicate the goodwill is more likely than not impaired. In determining whether it is more likely than not that a goodwill impairment exists, an entity should consider whether there are any adverse qualitative factors indicating that an impairment may exist. The Company adopted ASU No. 2010-28 on January 1, 2011. The adoption did not have any impact on the Company as none of its reporting units with goodwill has a zero or negative carrying amount.

ASU No. 2011-2, Receivables (Topic 310), A Creditor s Determination of Whether a Restructuring Is a Troubled Debt Restructuring

In April 2011, the FASB issued ASU No. 2011-2, which provides additional guidance and clarification to help creditors determine whether a creditor has granted a concession and whether a debtor is experiencing financial difficulties for purposes of determining whether a restructuring constitutes a troubled debt restructuring. The Company adopted ASU No. 2011-2 on July 1, 2011. The adoption did not have any impact on the Company s financial position, results of operations or cash flows.

Table of Contents

ASU No. 2011-8, Intangibles Goodwill and Other (Topic 350), Testing Goodwill for Impairment

In September 2011, the FASB issued ASU No. 2011-8, which amends the existing guidance for goodwill impairment testing. Under the amendments in ASU No. 2011-8, an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If, after this qualitative assessment, an entity determines that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary. Also, an entity has the option to bypass the qualitative assessment for any reporting unit in any period and proceed directly to performing the first step of the two-step goodwill impairment test. The amendments do not change the existing accounting guidance on how Step 1 and Step 2 of the goodwill impairment test are performed. In addition, an entity is no longer permitted to carry forward its detailed calculation of a reporting unit s fair value from a prior year as previously permitted under the existing guidance. ASU No. 2011-8 is effective for annual and interim goodwill impairment tests performed for fiscal periods beginning on or after December 15, 2011 and early adoption is permitted. AES elected to early adopt ASU No. 2011-8 for its annual goodwill impairment evaluations, which are performed at October 1 each year. The adoption is not expected to have a material impact on the Company s financial position, results of operations or cash flows in current or future periods.

Accounting Pronouncements Issued But Not Yet Effective

As of September 30, 2011, the following accounting standards have been issued, but are not yet effective for, and have not been adopted by AES.

ASU No. 2011-4, Fair Value Measurements (Topic 820), Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS

In May 2011, the FASB issued ASU No. 2011-4, which among other requirements, prohibits the use of the block discount factor for all fair value level hierarchies; permits an entity to measure the fair value of its financial instruments on a net basis when the related market risks are managed on a net basis; states the highest and best use concept is no longer relevant in the measurement of financial assets and liabilities; clarifies that a reporting entity should disclose quantitative information about the unobservable inputs used in Level 3 measurements and that the application of premiums and discounts is related to the unit of account for the asset or liability being measured at fair value; and requires expanded disclosures to describe the valuation process used for Level 3 measurements and the sensitivity of Level 3 measurements to changes in unobservable inputs. In addition, entities are required to disclose the hierarchy level for items which are not measured at fair value in the statement of financial position, but for which fair value is required to be disclosed. ASU No. 2011-4 is effective for the first interim or annual period beginning on or after December 15, 2011, or January 1, 2012 for AES. The adoption is not expected to have a material impact on the Company s financial position, results of operations or cash flows.

2. INVENTORY

The following table summarizes the Company s inventory balances as of September 30, 2011 and December 31, 2010:

	September 30, 2011	December 31, 2010
	(in millions)	
Coal, fuel oil and other raw materials	$ 377	$ 276
Spare parts and supplies	291	285
Total	$ 668	$ 561

7

3. FAIR VALUE

The fair value of current financial assets and liabilities, debt service reserves and other deposits approximates their reported carrying amounts. The fair value of non-recourse debt is estimated based upon the type of loan. The fair value of variable rate loans generally approximates their carrying amounts. For fixed rate loans, fair value is estimated using quoted market prices or discounted cash flow analyses. See Note 8 *Debt* for additional information on the fair value and carrying value of debt. The fair value of interest rate swap, cap and floor agreements, foreign currency forwards, swaps and options and energy derivatives is the estimated net amount that the Company would receive or pay to sell or transfer the agreements as of the balance sheet date.

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

The following table summarizes the carrying amount and fair value of certain of the Company s financial assets and liabilities as of September 30, 2011 and December 31, 2010:

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Assets				
Marketable securities	$ 1,093	$ 1,093	$ 1,767	$ 1,767
Derivatives	117	117	124	124
Total assets	$ 1,210	$ 1,210	$ 1,891	$ 1,891
Liabilities				
Debt	$ 20,878	$ 21,101	$ 19,550	$ 20,137
Derivatives	688	688	423	423
Total liabilities	$ 21,566	$ 21,789	$ 19,973	$ 20,560

Valuation Techniques:

The fair value measurement accounting guidance describes three main approaches to measuring the fair value of assets and liabilities: (1) market approach; (2) income approach and (3) cost approach. The market approach uses prices and other relevant information generated from market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to convert future amounts to a single present value amount. The measurement is based on current market expectations of the return on those future amounts. The cost approach is based on the amount that would currently be required to replace an asset. The Company measures its investments and derivatives at fair value on a recurring basis. Additionally, in connection with annual or event-driven impairment evaluations, certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis. These include long-lived tangible assets (i.e., property, plant and equipment), goodwill and intangible assets (e.g., sales concessions, land use rights and emissions allowances, etc.). In general, the Company determines the fair value of investments and derivatives using the market approach and the income approach, respectively. In the nonrecurring measurements of nonfinancial assets and liabilities, all three approaches are considered; however, fair value estimated under the income approach is often selected.

Investments

The Company s investments measured at fair value generally consist of marketable debt and equity securities. Equity securities are measured at fair value using quoted market prices. Debt securities primarily consist of unsecured debentures, certificates of deposit and government debt securities held by our Brazilian subsidiaries. Returns and pricing on these instruments are generally indexed to the CDI (Brazilian equivalent to London Inter-Bank Offered Rate, or LIBOR, a benchmark interest rate widely used by banks in the interbank lending market) or Selic (overnight borrowing rate) rates in Brazil. Fair value is determined from comparisons to market data obtained for similar assets and are considered Level 2 in the fair value hierarchy. For more detail regarding the fair value of investments see Note 4 *Investments in Marketable Securities*.

Derivatives

When deemed appropriate, the Company manages its risk from interest and foreign currency exchange rate and commodity price fluctuations through the use of over-the-counter financial and physical derivative instruments. The derivatives are primarily interest rate swaps to hedge non-recourse debt to establish a fixed rate on variable rate debt, foreign exchange instruments to hedge against currency fluctuations, commodity derivatives to hedge against commodity price fluctuations and embedded derivatives associated with commodity contracts. The Company s subsidiaries are counterparties to various over-the-counter derivatives, which include interest rate swaps and options, foreign currency options and forwards and commodity swaps. In addition, the Company s subsidiaries are counterparties to certain power purchase agreements (PPAs) and fuel supply agreements that are derivatives or include embedded derivatives.

For the derivatives where there is a standard industry valuation model, the Company uses that model to estimate the fair value. For the derivatives (such PPAs and fuel supply agreements that are derivatives or include embedded derivatives) where there is not a standard industry valuation model, the Company has created internal valuation models to estimate the fair value, using observable data to the extent available. For all derivatives, the income approach is used, which consists of forecasting future cash flows based on contractual notional amounts and applicable and available market data as of the valuation date. The following are among the most common market data inputs used in the income approach: volatilities, spot and forward benchmark interest rates (such as LIBOR and Euro Inter Bank Offered Rate (EURIBOR)), foreign exchange rates and commodity prices. Forward rates and prices are generally obtained from published information provided by pricing services for an instrument with the same duration as the derivative instrument being valued. In situations where significant inputs are not observable, the Company uses relevant techniques to best estimate the inputs, such as regression analysis, Monte Carlo simulation or prices for similarly traded instruments available in the market.

For each derivative, the income approach is used to estimate the cash flows over the remaining term of the contract. Those cash flows are then discounted using the relevant spot benchmark interest rate (such as LIBOR or EURIBOR) plus a spread that reflects the credit or nonperformance risk. This risk is estimated by the Company using credit spreads and risk premiums that are observable in the market, whenever possible, or estimated borrowing costs based on bank quotes, industry publications and/or information on financing closed on similar projects. To the extent that management can estimate the fair value of these assets or liabilities without the use of significant unobservable inputs, these derivatives are classified as Level 2.

In certain instances, the published forward rates or prices may not extend through the remaining term of the contract and management must make assumptions to extrapolate the curve, which necessitates the use of unobservable inputs, such as proxy commodity prices or historical settlements to forecast forward prices. In addition, in certain instances, there may not be third party data readily available, which requires the use of unobservable inputs. Similarly, in certain instances, the spread that reflects the credit or nonperformance risk is unobservable. The fair value hierarchy of an asset or a liability is based on the level of significance of the input assumptions. An input assumption is considered significant if it affects the fair value by at least 10%. Assets and liabilities are transferred to Level 3 when the use of unobservable inputs becomes significant. Similarly, when the use of unobservable input becomes insignificant for Level 3 assets and liabilities, they are transferred to Level 2.

Transfers in and out of Level 3 are from and to Level 2 and are determined as of the end of the reporting period. The Company has not had any Level 1 derivatives so there have not been any transfers between Levels 1 and 2.

Table of Contents

Nonfinancial Assets and Liabilities

For nonrecurring measurements derived using the income approach, fair value is determined using valuation models based on the principles of discounted cash flows (DCF). The income approach is most often used in the impairment evaluation of long-lived tangible assets, goodwill and intangible assets. The Company has developed internal valuation models for such valuations; however, an independent valuation firm may be engaged in certain situations. In such situations, the independent valuation firm largely uses DCF valuation models as the primary measure of fair value though other valuation approaches are also considered. A few examples of input assumptions to such valuations include macroeconomic factors such as growth rates, industry demand, inflation, exchange rates and power and commodity prices. Whenever possible, the Company attempts to obtain market observable data to develop input assumptions. Where the use of market observable data is limited or not possible for certain input assumptions, the Company develops its own estimates using a variety of techniques such as regression analysis and extrapolations.

For nonrecurring measurements derived using the market approach, recent market transactions involving the sale of identical or similar assets are considered. The use of this approach is limited because it is often difficult to find sale transactions of identical or similar assets. This approach is used in the impairment evaluations of certain intangible assets. Otherwise, it is used to corroborate the fair value determined under the income approach.

For nonrecurring measurements derived using the cost approach, fair value is typically determined using the replacement cost approach. Under this approach, the depreciated replacement cost of assets is determined by first determining the current replacement cost of assets and then applying the remaining useful life percentages to such cost. Further adjustments for economic and functional obsolescence are made to the depreciated replacement cost. This approach involves a considerable amount of judgment, which is why its use is limited to the measurement of a few long-lived tangible assets. Like the market approach, this approach is also used to corroborate the fair value determined under the income approach. For the nine months ended September 30, 2011, the Company did not measure any nonfinancial assets under the cost approach.

Fair Value Considerations:

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

Sources of market assumptions

The Company derives most of its market assumptions from market efficient data sources (e.g., Bloomberg and Platt s). To determine fair value, where market data is not readily available, management uses comparable market sources and empirical evidence to develop its own estimates of market assumptions.

Market liquidity

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

Table of Contents

Nonperformance risk

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

Nonperformance risk on the investments held by the Company is incorporated in the fair value derived from quoted market data to mark the investments to fair value.

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

Recurring Measurements

The following table sets forth, by level within the fair value hierarchy, the Company s financial assets and liabilities that were measured at fair value on a recurring basis as of September 30, 2011 and December 31, 2010. Financial assets and liabilities have been classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the determination of the fair value of the assets and liabilities and their placement within the fair value hierarchy levels.

	Quoted Market Prices in Active Market for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total September 30, 2011
		(in millions)		
Assets				
Available-for-sale securities	$ 2	$ 1,041	$ 40	$ 1,083
Trading securities	10	-	-	10
Derivatives	-	57	60	117
Total assets	$ 12	$ 1,098	$ 100	$ 1,210
Liabilities				
Derivatives	$ -	$ 419	$ 269	$ 688
Total liabilities	$ -	$ 419	$ 269	$ 688

Table of Contents

	Quoted Market Prices in Active Market for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total December 31, 2010
	(in millions)			
Assets				
Available-for-sale securities	$ 8	$ 1,707	$ 42	$ 1,757
Trading securities	10	-	-	10
Derivatives	-	63	61	124
Total assets	$ 18	$ 1,770	$ 103	$ 1,891
Liabilities				
Derivatives	$ -	$ 411	$ 12	$ 423
Total liabilities	$ -	$ 411	$ 12	$ 423

The following tables present a reconciliation of net derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the three and nine months ended September 30, 2011 and 2010 (presented net by type of derivative):

	Three Months Ended September 30, 2011				
	Interest Rate	Cross Currency	Foreign Currency	Commodity and Other	Total
			(in millions)		
Balance at July 1	$ (60)	$ 15	$ 38	$ 17	$ 10
Total gains (losses) (realized and unrealized):					
Included in earnings[(1)]	-	(3)	4	(44)	(43)
Included in other comprehensive income	(36)	(37)	-	-	(73)
Included in regulatory (assets) liabilities	-	-	-	(3)	(3)
Settlements	4	4	(1)	(8)	(1)
Transfers of assets (liabilities) into Level 3[(2)]	(101)	-	-	-	(101)
Transfers of (assets) liabilities out of Level 3[(2)]	2	-	-	-	2
Balance at September 30	$ (191)	$ (21)	$ 41	$ (38)	$ (209)
Total gains/(losses) for the period included in earnings attributable to the change in unrealized gains/(losses) relating to assets and liabilities held at the end of the period	$ -	$ (2)	$ 2	$ (52)	$ (52)

	Three Months Ended September 30, 2010				
	Interest Rate	Cross Currency	Foreign Currency	Commodity and Other	Total
			(in millions)		
Balance at July 1	$ (226)	$ (34)	$ 18	$ 19	$ (223)
Total gains (losses) (realized and unrealized):					
Included in earnings[(1)]	(2)	-	-	(3)	(5)
Included in other comprehensive income	(63)	24	(1)	-	(40)
Included in regulatory (assets) liabilities	(3)	-	-	(2)	(5)
Settlements	15	1	-	(3)	13
Transfers of assets (liabilities) into Level 3[(2)]	(3)	-	-	-	(3)
Transfers of (assets) liabilities out of Level 3[(2)]	26	-	-	-	26

Balance at September 30	$	(256)	$	(9)	$	17	$	11	$	(237)
Total gains/(losses) for the period included in earnings attributable to the change in unrealized gains/(losses) relating to assets and liabilities held at the end of the period	$	(1)	$	-	$	-	$	-	$	(1)

12

Table of Contents

	Interest Rate	Cross Currency	Foreign Currency	Commodity and Other	Total
	Nine Months Ended September 30, 2011 (in millions)				
Balance at January 1	$ (1)	$ 10	$ 22	$ 18	$ 49
Total gains (losses) (realized and unrealized):					
Included in earnings[1]	-	(5)	21	(50)	(34)
Included in other comprehensive income	(3)	(34)	-	-	(37)
Included in regulatory (assets) liabilities	-	-	-	3	3
Settlements	-	8	(2)	(9)	(3)
Transfers of assets (liabilities) into Level 3[2]	(189)	-	-	-	(189)
Transfers of (assets) liabilities out of Level 3[2]	2	-	-	-	2
Balance at September 30	$ (191)	$ (21)	$ 41	$ (38)	$ (209)
Total gains/(losses) for the period included in earnings attributable to the change in unrealized gains/(losses) relating to assets and liabilities held at the end of the period	$ -	$ (2)	$ 18	$ (56)	$ (40)

	Interest Rate	Cross Currency	Foreign Currency	Commodity and Other	Total
	Nine Months Ended September 30, 2010 (in millions)				
Balance at January 1	$ (12)	$ (12)	$ -	$ 24	$ -
Total gains (losses) (realized and unrealized):					
Included in earnings[1]	1	4	19	1	25
Included in other comprehensive income	(20)	(5)	-	-	(25)
Included in regulatory (assets) liabilities	(6)	-	-	2	(4)
Settlements	6	4	(1)	(16)	(7)
Transfers of assets (liabilities) into Level 3[2]	(251)	-	(1)	-	(252)
Transfers of (assets) liabilities out of Level 3[2]	26	-	-	-	26
Balance at September 30	$ (256)	$ (9)	$ 17	$ 11	$ (237)
Total gains/(losses) for the period included in earnings attributable to the change in unrealized gains/(losses) relating to assets and liabilities held at the end of the period	$ (2)	$ 5	$ 20	$ (10)	$ 13

(1) The gains (losses) included in earnings for these Level 3 derivatives are classified as follows: interest rate and cross currency derivatives as interest expense, foreign currency derivatives as foreign currency transaction gains (losses) and commodity and other derivatives as either non-regulated revenue, non-regulated cost of sales, or other expense. See Note 5 *Derivative Instruments and Hedging Activities* for further information regarding the classification of gains and losses included in earnings in the condensed consolidated statements of operations.

(2) Transfers in and out of Level 3 are determined as of the end of the reporting period and are from and to Level 2, as the Company has no Level 1 derivative assets or liabilities. The (assets) liabilities transferred out of Level 3 are primarily the result of a decrease in the significance of unobservable inputs used to calculate the credit valuation adjustments of these derivative instruments. Similarly, the assets (liabilities) transferred into Level 3 are primarily the result of an increase in the significance of unobservable inputs used to calculate the credit valuation adjustments of these derivative instruments.

Table of Contents

The following table presents a reconciliation of available-for-sale securities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the three and nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Balance at beginning of period[1]	$ 40	$ 42	$ 42	$ 42
Settlements	-	-	(2)	-
Balance at September 30	$ 40	$ 42	$ 40	$ 42
Total gains/(losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets held at the end of the period	$ -	$ -	$ -	$ -

[1] Available-for-sale securities in Level 3 are variable rate demand notes which have failed remarketing and for which there are no longer adequate observable inputs available to measure the fair value.

Nonrecurring Measurements:

For purposes of impairment evaluation, the Company measured the fair value of long-lived assets and equity method investments under the fair value measurement accounting guidance. For purposes of the measurement of impairment expense, the Company compares the fair value of assets and liabilities at the evaluation date to the carrying amount at the end of the month prior to the evaluation date. The following table summarizes major categories of assets and liabilities measured at fair value on a nonrecurring basis during the period and their level within the fair value hierarchy:

	Nine Months Ended September 30, 2011				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Gross Loss
	(in millions)				
Long-lived assets held and used:					
Wind turbines and deposits	$ 161	$ -	$ 45	$ -	$ 116
Kelanitissa	66	-	-	29	37
Carbon Reduction Projects	49	-	-	11	33[1]
Bohemia	14	-	5	-	9
Equity method affiliates:					
YangCheng	100	-	-	26	74
Goodwill:					
Chigen	17	-	-	-	17

	Nine Months Ended September 30, 2010				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Gross Loss
	(in millions)				
Long-lived assets held and used:					
Southland (Huntington Beach)	$ 288	$ -	$ -	$ 88	$ 200
Tisza II	160	-	-	75	85
Goodwill:					
Deepwater	18	-	-	-	18

(1) The carrying amounts and fair value of the asset groups also include other assets and liabilities; however, impairment expense recognized was limited to the carrying amounts of long-lived assets.

Long-lived Assets Held and Used

Wind Turbines and Deposits. During the third quarter of 2011, the Company determined that certain wind turbines and deposits held by our Wind Generation business were impaired. The long-lived assets with a carrying amount of $161 million were written down to their estimated fair value of $45 million under the market approach. This resulted in the recognition of asset impairment expense of $116 million for the three and nine months ended September 30, 2011.

Kelanitissa. During the second quarter of 2011, the Company determined the long-lived assets at Kelanitissa, our diesel-fired plant in Sri Lanka, were impaired. The long-lived assets with a carrying amount of $66 million were written down to their estimated fair value of $33 million based on a discounted cash flow analysis. An additional impairment of $4 million was recognized in the three months ended September 30, 2011. This resulted in the recognition of asset impairment expense of $37 million for the nine months ended September 30, 2011.

Carbon Reduction Projects. During the third quarter of 2011, the Company determined there were impairment indicators for the long-lived asset groups at Carbon Reduction projects, our emission reduction credit projects in Asia and Latin America. The long-lived asset groups with an aggregate carrying amount of $49 million were written down as their estimated fair value was $11 million based on discounted cash flows analysis. This resulted in the recognition of asset impairment expense of $33 million for the three and nine months ended September 30, 2011.

Tisza II and Southland (Huntington Beach). During the third quarter of 2010, the Company determined there were impairment indicators for the long-lived assets at Tisza II, our gas-fired generation plant in Hungary, and Southland, our gas-fired generation plants in California. These long-lived assets had carrying amounts of $160 million and $288 million, respectively and were written down to their fair value of $75 million and $88 million, respectively. These resulted in the recognition of asset impairment expense of $85 million and $200 million, respectively during the three and nine months ended September 30, 2010.

For further discussion of these impairments, see Note 14 *Impairments*.

Equity Method Affiliate

YangCheng. During the third quarter of 2011, the Company determined that the carrying amount of YangCheng, a 2,100 MW venture in China in which AES owns a 25% interest, had incurred an other-than-temporary impairment. YangCheng s carrying amount of $100 million was written down to its estimated fair value of $26 million determined under the income approach. This resulted in the recognition of other non-operating expense of $74 million for the three and nine months ended September 30, 2011. See Note 15 *Other Non-Operating Expense* for further information.

Goodwill

During the third quarter of 2011, the Company determined there were impairment indicators for the goodwill at Chigen, our holding company in China that holds AES interests in Chinese ventures. Goodwill of $17 million was written down to its implied fair value of zero during an interim impairment evaluation, resulting in the recognition of goodwill impairment of $17 million for the three and nine months ended September 30, 2011.

During the third quarter of 2010, the Company determined there were impairment indicators for the long-lived assets and goodwill at Deepwater, our pet coke-fired generation plant in Texas. Goodwill with an aggregate carrying amount of $18 million was written down to its implied fair value of zero, resulting in the recognition of goodwill impairment of $18 million for the nine months ended September 30, 2010.

For further discussion, see Note 14 *Impairments.*

Table of Contents

Discontinued Operations and Held for Sale Businesses

The Company determined the fair value of nonfinancial assets and liabilities of our held for sale businesses during the nine months ended September 30, 2010. These included the Company s operations in Pakistan, Oman and Qatar. See Note 16 *Discontinued Operations and Held for Sale Businesses* for further information.

4. INVESTMENTS IN MARKETABLE SECURITIES

The following table sets forth the Company s investments in marketable debt and equity securities as of September 30, 2011 and December 31, 2010 by security class and by level within the fair value hierarchy. The security classes are determined based on the nature and risk of a security and are consistent with how the Company manages, monitors and measures its marketable securities.

	September 30, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
				(in millions)				
AVAILABLE-FOR-SALE:[1]								
Debt securities:								
Unsecured debentures[2]	$ -	$ 498	$ -	$ 498	$ -	$ 723	$ -	$ 723
Certificates of deposit[2]	-	447	-	447	-	876	-	876
Government debt securities	-	40	-	40	-	47	-	47
Other debt securities	-	-	40	40	-	-	42	42
Subtotal	-	985	40	1,025	-	1,646	42	1,688
Equity securities:								
Mutual funds	-	56	-	56	1	61	-	62
Common stock	2	-	-	2	7	-	-	7
Subtotal	2	56	-	58	8	61	-	69
Total available-for-sale	2	1,041	40	1,083	8	1,707	42	$ 1,757
TRADING:								
Equity securities:								
Mutual funds	10	-	-	10	10	-	-	10
Total trading	10	-	-	10	10	-	-	10
TOTAL	$ 12	$ 1,041	$ 40	$ 1,093	$ 18	$ 1,707	$ 42	$ 1,767

(1) Cost/amortized cost approximated fair value at September 30, 2011 and December 31, 2010, with the exception of certain common stock investments with a cost basis and fair value of $4 million and $2 million, respectively, at September 30, 2011, and a cost basis and fair value of $6 million and $7 million, respectively, at December 31, 2010.

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

As of September 30, 2011, all available-for-sale debt securities had stated maturities within one year, with the exception of $40 million of variable rate demand notes held by IPL. These securities, classified as other debt securities in the table above, had stated maturities of greater than ten years.

The following table summarizes the pre-tax gains and losses related to available-for-sale and trading securities for the three and nine months ended September 30, 2011 and 2010. Gains and losses on the sale of investments are determined using the specific identification method. For the three and nine months ended

Table of Contents

September 30, 2011 and 2010, there were no realized losses on the sale of available-for-sale securities and no other-than-temporary impairment of marketable securities recognized in earnings or other comprehensive income.

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions)		(in millions)	
Losses included in earnings that relate to trading securities held at the reporting date	$ (2)	$ (1)	$ (1)	$ -
Unrealized losses on available-for-sale securities included in other comprehensive income	$ (1)	$ -	$ (4)	$ (10)
Proceeds from sales of available-for-sale securities	$ 1,134	$ 1,420	$ 4,218	$ 4,644
Gross realized gains on sales	$ 1	$ -	$ 5	$ 2

5. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Risk Management Objectives

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

Interest Rate Risk

AES and its subsidiaries utilize variable rate debt financing for construction projects and operations, resulting in an exposure to interest rate risk. Interest rate swap, cap and floor agreements are entered into to manage interest rate risk by effectively fixing or limiting the interest rate exposure on the underlying financing. These interest rate contracts range in maturity through 2030, and are typically designated as cash flow hedges. The following table sets forth, by underlying type of interest rate index, the Company s current and maximum outstanding notional under its interest rate derivative instruments, the weighted average remaining term and the percentage of variable-rate debt hedged that is based on the related index as of September 30, 2011 regardless of whether the derivative instruments are in qualifying cash flow hedging relationships:

	September 30, 2011					
	Current		Maximum[1]			
Interest Rate Derivatives	Derivative Notional	Derivative Notional Translated to USD	Derivative Notional	Derivative Notional Translated to USD	Weighted Average Remaining Term[1] (in years)	% of Debt Currently Hedged by Index[2]
		(in millions)				
Libor (U.S. Dollar)	3,511	$ 3,511	3,585	$ 3,585	9	75%
Euribor (Euro)	1,072	1,435	1,072	1,435	13	66%
Libor (British Pound Sterling)	63	98	72	112	12	87%
Securities Industry and Financial Markets Association Municipal Swap Index (U.S. Dollar)	40	40	40	40	11	N/A[3]

(1) The Company s interest rate derivative instruments primarily include accreting and amortizing notionals. The maximum derivative notional represents the largest notional at any point between September 30, 2011 and the maturity of the derivative instrument, which includes forward starting derivative instruments. The weighted average remaining term represents the remaining tenor of our interest rate derivatives weighted by the corresponding maximum notional.

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

(3) The debt that was being hedged is no longer exposed to variable interest payments because it is now held on IPL s behalf and no longer bears interest.

Table of Contents

Cross currency swaps are utilized in certain instances to manage the risk related to fluctuations in both interest rates and certain foreign currencies. These cross currency contracts range in maturity through 2028. The following table sets forth, by type of foreign currency denomination, the Company s outstanding notional amount under its cross currency derivative instruments as of September 30, 2011, which are all in qualifying cash flow hedge relationships. These swaps are amortizing and therefore the notional amount represents the maximum outstanding notional amount as of September 30, 2011:

	September 30, 2011			
Cross Currency Swaps	**Notional**	**Notional Translated to USD**	**Weighted Average Remaining Term[(1)]**	**% of Debt Currently Hedged by Index[(2)]**
		(in millions)	**(in years)**	
Chilean Unidad de Fomento (CLF)	6	$ 237	14	83%

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

Foreign Currency Risk

We are exposed to foreign currency risk as a result of our investments in foreign subsidiaries and affiliates. AES operates businesses in many foreign countries and such operations may be impacted by significant fluctuations in foreign currency exchange rates. Foreign currency options and forwards are utilized, where deemed appropriate, to manage the risk related to fluctuations in certain foreign currencies. These foreign currency contracts range in maturity through 2015. The following tables set forth, by type of foreign currency denomination, the Company s outstanding notional amounts over the remaining terms of its foreign currency derivative instruments as of September 30, 2011 regardless of whether the derivative instruments are in qualifying hedging relationships:

	September 30, 2011			
Foreign Currency Options	**Notional**	**Notional Translated to USD[(1)]**	**Probability Adjusted Notional[(2)]**	**Weighted Average Remaining Term[(3)]**
		(in millions)		**(in years)**
Brazilian Real (BRL)	173	$ 105	$ 96	<1
Euro (EUR)	67	96	82	<1
British Pound (GBP)	29	47	40	<1
Argentine Peso (ARS)	88	20	8	<1

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

	September 30, 2011		
Foreign Currency Forwards	**Notional**	**Notional Translated to USD**	**Weighted Average Remaining Term[(1)]**
		(in millions)	**(in years)**
Chilean Peso (CLP)	98,944	$ 201	<1
Euro (EUR)	123	169	2
Colombian Peso (COP)	80,376	44	<1
British Pound (GBP)	11	17	1
Argentine Peso (ARS)	61	13	1

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

In addition, certain of our subsidiaries have entered into contracts which contain embedded derivatives that require separate valuation and accounting due to the fact that the item being purchased or sold is denominated in a currency other than the functional currency of that subsidiary or the currency of the item. These contracts range in maturity through 2025. The following table sets forth, by type of foreign currency denomination, the Company s outstanding notional over the remaining terms of its foreign currency embedded derivative instruments as of September 30, 2011:

	September 30, 2011		
Embedded Foreign Currency Derivatives	**Notional**	**Notional Translated to USD (in millions)**	**Weighted Average Remaining Term(1) (in years)**
Philippine Peso (PHP)	15,973	$ 363	2
Argentine Peso (ARS)	904	215	11
Kazakhstani Tenge (KZT)	30,606	207	9
Hungarian Forint (HUF)	10,114	46	<1
Euro (EUR)	20	27	2
Brazilian Real (BRL)	4	2	1

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

Commodity Price Risk

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

The PPAs and fuel supply agreements entered into by the Company are evaluated to determine if they meet the definition of a derivative or contain embedded derivatives, either of which requires separate valuation and accounting. To be a derivative under the accounting standards for derivatives and hedging, an agreement would need to have a notional and an underlying, require little or no initial net investment and could be net settled. Generally, these agreements do not meet the definition of a derivative, often due to the inability to be net settled. On a quarterly basis, we evaluate the markets for the commodities to be delivered under these agreements to determine if facts and circumstances have changed such that the agreements could then be net settled and meet the definition of a derivative.

Nonetheless, certain of the PPAs and fuel supply agreements entered into by certain of the Company s subsidiaries are derivatives or contain embedded derivatives requiring separate valuation and accounting. These contracts range in maturity through 2024. The following table sets forth, by type of commodity, the Company s outstanding notionals for the remaining term of its commodity derivatives and embedded derivative instruments as of September 30, 2011:

	September 30, 2011	
Commodity Derivatives	**Notional (in millions)**	**Weighted Average Remaining Term(1) (in years)**
Natural gas (MMBTU)	33	11
Aluminum (MWh)	16(2)	8
Petcoke (Metric tons)	13	13

Table of Contents

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

(2) Sonel s PPA with its primary offtaker, an aluminum smelter, contains an embedded derivative which reflects the linkage of our energy contract pricing, in part, to the price of aluminum as quoted on the London Metals Exchange, a global metals market maker (as required by contract). While the linkage between the contract price of power based on forecasted forward aluminum price curves and the Cameroon market price for power provides for economic alignment between Sonel s financial results under the PPA and the offtaker s financial performance, to the extent there are fluctuations in the price of aluminum as compared to the market price for power under our PPA, we may be exposed to significant swings in earnings through mark-to-market adjustments of the embedded derivative as the market price for aluminum has proven to be volatile.

Accounting and Reporting

The following table sets forth the Company s derivative instruments as of September 30, 2011 and December 31, 2010 by type of derivative and by level within the fair value hierarchy. Derivative assets and liabilities are recognized at their fair value. Derivative assets and liabilities are combined with other balances and included in the following captions in our condensed consolidated balance sheets: current derivative assets in other current assets, noncurrent derivative assets in other noncurrent assets, current derivative liabilities in accrued and other liabilities and long-term derivative liabilities in other long-term liabilities.

	September 30, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)				(in millions)			
Assets								
Current assets:								
Foreign currency derivatives	$ -	$ 48	$ 4	$ 52	$ -	$ 4	$ 3	$ 7
Commodity and other derivatives	-	-	5	5	-	2	3	5
Total current assets	-	48	9	57	-	6	6	12
Noncurrent assets:								
Interest rate derivatives	-	-	-	-	-	49	-	49
Cross currency derivatives	-	-	1	1	-	-	12	12
Foreign currency derivatives	-	5	49	54	-	4	27	31
Commodity and other derivatives	-	4	1	5	-	4	16	20
Total noncurrent assets	-	9	51	60	-	57	55	112
Total assets	$ -	$ 57	$ 60	$ 117	$ -	$ 63	$ 61	$ 124
Liabilities								
Current liabilities:								
Interest rate derivatives	$ -	$ 102	$ 29	$ 131	$ -	$ 137	$ -	$ 137
Cross currency derivatives	-	-	5	5	-	-	2	2
Foreign currency derivatives	-	6	1	7	-	13	-	13
Commodity and other derivatives	-	5	3	8	-	-	-	-
Total current liabilities	-	113	38	151	-	150	2	152
Long-term liabilities:								
Interest rate derivatives	-	294	162	456	-	246	1	247
Cross currency derivatives	-	-	17	17	-	-	-	-
Foreign currency derivatives	-	11	11	22	-	15	8	23
Commodity and other derivatives	-	1	41	42	-	-	1	1

Total long-term liabilities		-		306		231		537		-		261		10		271
Total liabilities	$	-	$	419	$	269	$	688	$	-	$	411	$	12	$	423

Table of Contents

The following table sets forth the fair value and balance sheet classification of derivative instruments as of September 30, 2011 and December 31, 2010:

	September 30, 2011			December 31, 2010		
	Designated as Hedging Instruments	Not Designated as Hedging Instruments (in millions)	Total	Designated as Hedging Instruments	Not Designated as Hedging Instruments (in millions)	Total
Assets						
Current assets:						
Foreign currency derivatives	$ 17	$ 35	$ 52	$ -	$ 7	$ 7
Commodity and other derivatives	-	5	5	-	5	5
Total current assets	17	40	57	-	12	12
Noncurrent assets:						
Interest rate derivatives	-	-	-	49	-	49
Cross currency derivatives	1	-	1	12	-	12
Foreign currency derivatives	2	52	54	-	31	31
Commodity and other derivatives	-	5	5	-	20	20
Total noncurrent assets	3	57	60	61	51	112
Total assets	$ 20	$ 97	$ 117	$ 61	$ 63	$ 124
Liabilities						
Current liabilities:						
Interest rate derivatives	$ 126	$ 5	$ 131	$ 126	$ 11	$ 137
Cross currency derivatives	5	-	5	2	-	2
Foreign currency derivatives	1	6	7	8	5	13
Commodity and other derivatives	-	8	8	-	-	-
Total current liabilities	132	19	151	136	16	152
Long-term liabilities:						
Interest rate derivatives	437	19	456	232	15	247
Cross currency derivatives	17	-	17	-	-	-
Foreign currency derivatives	-	22	22	-	23	23
Commodity and other derivatives	-	42	42	-	1	1
Total long-term liabilities	454	83	537	232	39	271
Total liabilities	$ 586	$ 102	$ 688	$ 368	$ 55	$ 423

The Company has elected not to offset net derivative positions in the financial statements. Accordingly, the Company does not offset such derivative positions against the fair value of amounts (or amounts that approximate fair value) recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) under master netting arrangements. At September 30, 2011 and December 31, 2010, we held no cash collateral that we received from counterparties to our derivative positions. As we have not received collateral, our derivative assets are exposed to the credit risk of the respective counterparty and, due to this credit risk, the fair values of our derivative assets (as shown in the above two tables) have been reduced by a credit valuation adjustment. Also, at September 30, 2011 and December 31, 2010, we had no cash collateral posted with (held by) counterparties to our derivative positions.

Table of Contents

The table below sets forth the pre-tax accumulated other comprehensive income (loss) expected to be recognized as an increase (decrease) to income from continuing operations before income taxes over the next twelve months as of September 30, 2011 for the following types of derivatives:

	Accumulated Other Comprehensive Income (Loss) (in millions)
Interest rate derivatives	$ (116)
Cross currency derivatives	$ (1)
Foreign currency derivatives	$ 16

The balance in accumulated other comprehensive loss related to derivative transactions will be reclassified into earnings as interest expense is recognized for interest rate hedges and cross currency swaps, as depreciation is recognized for interest rate hedges during construction, and as foreign currency gains and losses are recognized for hedges of foreign currency exposure. These balances are included in the condensed consolidated statements of cash flows as operating and/or investing activities based on the nature of the underlying transaction.

The following tables set forth the gains (losses) recognized in accumulated other comprehensive loss (AOCL) and earnings related to the effective portion of derivative instruments in qualifying cash flow hedging relationships, as defined in the accounting standards for derivatives and hedging, for the three and nine months ended September 30, 2011 and 2010:

	Gains (Losses) Recognized in AOCL Three Months Ended September 30,		Classification in Condensed Consolidated Statements of Operations	Gains (Losses) Reclassified from AOCL into Earnings[1] Three Months Ended September 30,	
	2011	2010		2011	2010
	(in millions)			(in millions)	
Interest rate derivatives	$ (297)	$ (138)	Interest expense	$ (35)[2]	$ (24)[2]
			Non-regulated cost of sales	(1)[2]	(3)[2]
			Net equity in earnings of affiliates	(1)	(1)
Cross currency derivatives	(37)	24	Interest expense	(3)	-
			Foreign currency transaction gains (losses)	(26)	30
Foreign currency derivatives	29	(12)	Foreign currency transaction gains (losses)	3	1
Commodity and other derivatives	-	(4)	Non-regulated cost of sales	(2)	-
Total	$ (305)	$ (130)		$ (65)	$ 3

	Gains (Losses) Recognized in AOCL Nine Months Ended September 30,		Classification in Condensed Consolidated Statements of Operations	Gains (Losses) Reclassified from AOCL into Earnings[1] Nine Months Ended September 30,	
	2011	2010		2011	2010
	(in millions)			(in millions)	
Interest rate derivatives	$ (389)	$ (388)	Interest expense	$ (88)[2]	$ (81)[2]
			Non-regulated cost of sales	(3)[2]	(3)[2]

			Net equity in earnings of affiliates	(3)	(3)
Cross currency derivatives	(34)	(5)	Interest expense	(7)	(1)
			Foreign currency transaction gains (losses)	(20)	16
Foreign currency derivatives	27	(5)	Foreign currency transaction gains (losses)	(1)	1
Commodity and other derivatives	-	(4)	Non-regulated cost of sales	(2)	-
Total	$ (396)	$ (402)		$ (124)	$ (71)

(1) Excludes $0 million and $20 million related to discontinued operations for the three months ended September 30, 2011 and 2010, respectively, and $0 million and $30 million related to discontinued operations for the nine months ended September 30, 2011 and 2010, respectively.

(2) Includes amounts that were reclassified from AOCL related to derivative instruments that previously, but no longer, qualify for cash flow hedge accounting.

The following table sets forth the pre-tax gains (losses) recognized in earnings related to the ineffective portion of derivative instruments in qualifying cash flow hedging relationships, as defined in the accounting standards for derivatives and hedging, for the three and nine months ended September 30, 2011 and 2010:

	Classification in Condensed Consolidated Statements of Operations	Gains (Losses) Recognized in Earnings Three Months Ended September 30,		Gains (Losses) Recognized in Earnings Nine Months Ended September 30,	
		2011	2010	2011	2010
		(in millions)		(in millions)	
Interest rate derivatives	Interest expense	$ 1	$ (10)	$ (6)	$ (18)
	Net equity in earnings of affiliates	(1)	-[1]	(2)	(1)
Cross currency derivatives	Interest expense	(3)	-[1]	(5)	4
Foreign currency derivatives	Foreign currency transaction gains (losses)	-[1]	-[1]	-[1]	-[1]
Total		$ (3)	$ (10)	$ (13)	$ (15)

(1) De minimis amount.

The following table sets forth the gains (losses) recognized in earnings related to derivative instruments not designated as hedging instruments under the accounting standards for derivatives and hedging, for the three and nine months ended September 30, 2011 and 2010:

	Classification in Condensed Consolidated Statements of Operations	Gains (Losses) Recognized in Earnings Three Months Ended September 30,		Gains (Losses) Recognized in Earnings Nine Months Ended September 30,	
		2011	2010	2011	2010
		(in millions)		(in millions)	
Interest rate derivatives	Interest expense	$ (1)	$ (3)	$ (2)	$ (8)
Foreign exchange derivatives	Foreign currency transaction gains (losses)	27	(7)	54	(32)
	Net equity in earnings of affiliates	-	-	-	2
Commodity and other derivatives	Non-regulated revenue	(54)	1	(63)	5
	Non-regulated cost of sales	3	(3)	2	2
Total		$ (25)	$ (12)	$ (9)	$ (31)

Table of Contents

In addition, IPL has two derivative instruments for which the gains and losses are accounted for in accordance with accounting standards for regulated operations, as regulatory assets or liabilities. Gains and losses on these derivatives due to changes in the fair value of these derivatives are probable of recovery through future rates and are initially recognized as an adjustment to the regulatory asset or liability and recognized through earnings when the related costs are recovered through IPL s rates. Therefore, these gains and losses are excluded from the above table. The following table sets forth the change in regulatory assets and liabilities resulting from the change in the fair value of these derivatives for the three and nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions)			
(Increase) decrease in regulatory assets	$ (4)	$ (3)	$ (6)	$ (6)
Increase (decrease) in regulatory liabilities	$ (3)	$ (2)	$ 3	$ 2

Credit Risk-Related Contingent Features

Gener, our business in Chile, has cross currency swap agreements with counterparties to swap Chilean inflation indexed bonds issued in December 2007 into U.S. Dollars. The derivative agreements contain credit contingent provisions which would permit the counterparties with which Gener is in a net liability position to require collateral credit support when the fair value of the derivatives exceeds the unsecured thresholds established in the agreement. These thresholds vary based on Gener s credit rating. If Gener s credit rating were to fall below the minimum threshold established in the swap agreements, the counterparties can demand immediate collateralization of the entire mark-to-market value of the swaps (excluding credit valuation adjustments) if Gener is in a net liability position, which was $21 million at September 30, 2011. The swaps were in a net asset position at December 31, 2010. As of September 30, 2011 and December 31, 2010, Gener had not posted collateral to support these swaps.

6. INVESTMENTS IN AND ADVANCES TO AFFILIATES

In February 2011, the Company acquired a 49.6% interest in Entek Elektrik Uretim A.S. (Entek) for approximately $136 million. Additional purchase consideration of $13 million was paid in May 2011, increasing the total purchase consideration to $149 million. Entek owns and operates two gas-fired generation facilities in Turkey with an aggregate capacity of 312 MW, and is also engaged in an energy trading business. The Company has significant influence, but not control, of Entek and accordingly the investment has been accounted for under the equity method of accounting.

7. FINANCING RECEIVABLES

Accounts and notes receivable are carried at amortized cost. The Company periodically assesses the collectability of accounts receivable by considering factors such as specific evaluation of collectability, historical collection experience, the age of accounts receivable and other available evidence of the collectability, and records an allowance for doubtful accounts for the estimated uncollectable amount as appropriate. Certain of our businesses charge interest on accounts receivable under contractual terms or where charging interest is a customary business practice. In such cases, interest income is recognized on an accrual basis. In situations where the collection of interest is uncertain, interest income is recognized as cash is received. Individual accounts and notes receivable are written off when they are no longer deemed collectable.

Included in Noncurrent other assets on the condensed consolidated balance sheets as of September 30, 2011 and December 31, 2010 are long-term financing receivables of $282 million and $151 million, respectively,

Table of Contents

primarily with certain Latin American governmental bodies. These receivables have contractual maturities of greater than one year and are being collected in installments as scheduled. Of the total $282 million as of September 30, 2011, $220 million and $50 million, respectively, relate to our businesses in Argentina and the Dominican Republic. The remaining amounts relate to our distribution businesses in Brazil.

8. DEBT

The Company has two types of debt reported on its condensed consolidated balance sheet: non-recourse and recourse debt. Non-recourse debt is used to fund investments and capital expenditures for the construction and acquisition of electric power plants, wind projects, distribution companies and other project-related investments at our subsidiaries. Non-recourse debt is generally secured by the capital stock, physical assets, contracts and cash flows of the related subsidiary. Absent guarantees, intercompany loans or other credit support, the default risk is limited to the respective business and is without recourse to the Parent Company and other subsidiaries, though the Company s equity investments and/or subordinated loans to projects (if any) are at risk. Recourse debt is direct borrowings by the Parent Company and is used to fund development, construction or acquisitions, including serving as funding for equity investments or loans to the affiliates. The Parent Company s debt is, among other things, recourse to the Parent Company and is structurally subordinated to the affiliates debt.

The following table summarizes the carrying amount and estimated fair values of the Company s recourse and non-recourse debt as of September 30, 2011 and December 31, 2010:

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Non-recourse debt	$ 14,686	$ 14,885	$ 14,938	$ 15,269
Recourse debt	6,192	6,216	4,612	4,868
Total debt	$ 20,878	$ 21,101	$ 19,550	$ 20,137

Recourse and non-recourse debt are carried at amortized cost. The fair value of recourse debt is estimated based on quoted market prices. The fair value of non-recourse debt is estimated differently based upon the type of loan. The fair value of fixed rate loans is estimated using quoted market prices, if available, or a discounted cash flow analysis. In the discounted cash flow analysis, the discount rate is based on the credit rating of the individual debt instruments if available, or the credit rating of the subsidiary. If the subsidiary s credit rating is not available, a synthetic credit rating is determined using certain key metrics, including cash flow ratios and interest coverage, as well as other industry specific factors. For subsidiaries located outside the U.S., in the event that the country rating is lower than the credit rating previously determined, the country rating is used for the purposes of the discounted cash flow analysis. The fair value of recourse and non-recourse debt excludes accrued interest at the valuation date.

The fair value was determined using available market information as of September 30, 2011. The Company is not aware of any factors that would significantly affect the fair value amounts subsequent to September 30, 2011.

Table of Contents

Non-Recourse Debt

The following table summarizes the Company s subsidiary non-recourse debt in default or accelerated as of September 30, 2011 and is in the current portion of non-recourse debt unless otherwise indicated:

Subsidiary	Primary Nature of Default	September 30, 2011 Default Amount	Net Assets
		(in millions)	
Maritza	Covenant	$ 935	$ 216
Sonel	Covenant	342	306
Kelanitissa	Covenant	22	6
Total		$ 1,299	

Included in Current liabilities of discontinued and held for sale businesses in the condensed consolidated balance sheet as of September 30, 2011 is approximately $203 million of non-recourse debt relating to our businesses in New York, which has been classified as current due to certain facts and circumstances that create significant uncertainty about the business s ability to generate sufficient cash flows and remain in compliance with the terms of its contractual obligations in the next twelve months.

None of the subsidiaries that are currently in default are subsidiaries that met the applicable definition of materiality under AES corporate debt agreements as of September 30, 2011 in order to trigger an event of default or permit acceleration under such indebtedness. The bankruptcy or acceleration of material amounts of debt at such entities would cause a cross default under the recourse senior secured credit facility. However, as a result of additional dispositions of assets, other significant reductions in asset carrying values or other matters in the future that may impact our financial position and results of operations or the financial position or results of operations of an individual subsidiary, it is possible that one or more of these subsidiaries could fall within the definition of a material subsidiary and thereby a bankruptcy or an acceleration of its non-recourse debt trigger an event of default and possible acceleration of the indebtedness under the AES Parent Company s outstanding debt securities.

On October 3, 2011, Dolphin Subsidiary II, Inc. (Dolphin II), a newly formed, wholly owned special purpose indirect subsidiary of AES, entered into an indenture (the Indenture) with Wells Fargo Bank, N.A. (the Trustee) as part of its issuance of $450 million aggregate principal amount of 6.50% senior notes due 2016 (the 2016 Notes) and $800 million aggregate principal amount of 7.25% senior notes due 2021 (the 7.25% 2021 Notes , together with the 2016 Notes, the notes) to finance the pending acquisition (the Acquisition) by AES of DPL Inc. (DPL). See Note 17 *Acquisitions* for further information.

Interest on the 2016 Notes and the 7.25% 2021 Notes accrues at a rate of 6.50% and 7.25% per year, respectively, and is payable on April 15 and October 15 of each year, beginning April 15, 2012. Prior to September 15, 2016 with respect to the 2016 Notes or July 15, 2021 with respect to the 7.25% 2021 Notes, Dolphin II may redeem some or all of the 2016 Notes or 7.25% 2021 Notes at par, plus a make-whole amount set forth in the Indenture and accrued and unpaid interest. At any time on or after September 15, 2016 or July 15, 2021 with respect to the 2016 Notes and 7.25% 2021 Notes, respectively, Dolphin II may redeem some or all of the 2016 Notes or 7.25% 2021 Notes at par plus accrued and unpaid interest.

The proceeds from issuance of the notes were deposited into an escrow account pledged for the benefit of the Trustee pending the consummation of the Acquisition. The notes are subject to a special mandatory redemption at a price of 101% of the offering price of the notes plus accrued and unpaid interest in the event that the Acquisition is not consummated on or before September 30, 2012. If the acquisition closes on or before such date, Dolphin II will concurrently merge with and into DPL, with DPL being the surviving company and obligor under the notes.

Table of Contents

On September 28, 2011, the Company provided a letter of credit for approximately $115 million in favor of the escrow agent for the benefit of the Trustee pending the consummation of the Acquisition to cover payment of the interest expense from October 3, 2011 to September 30, 2012, the discount paid to the initial purchasers of the notes and special mandatory redemption price of 1% of the offering price of the notes. On September 29, 2011, at the instructions of the Dolphin II, escrow agent drew the entire amount of the letter of credit and deposited into the same escrow account for the benefit of the Trustee pending the consummation of the Acquisition. At the Acquisition consummation, any excess amount in the escrow account will be returned to Dolphin II.

Recourse Debt

During the nine months ended September 30, 2011, the Company secured recourse debt of $2.05 billion. The proceeds of the debt may, among other things, be used to partially finance the Company s contemplated acquisition of DPL Inc, as discussed further in Note 17 *Acquisitions*.

On May 27, 2011, the Company secured a $1.05 billion term loan under a senior secured credit facility (the senior secured term loan). The senior secured term loan will bear annual interest, at the Company s option, at a variable rate of LIBOR plus 3.25% or Base Rate plus 2.25%, and will mature on the seventh anniversary of the closing date. The senior secured term loan is subject to certain customary representations, covenants and events of default.

On June 15, 2011, the Company issued $1 billion aggregate principal amount of 7.375% senior unsecured notes maturing July 1, 2021 (the 7.375% 2021 Notes). Upon a change of control, the Company must offer to repurchase the 7.375% 2021 Notes at a price equal to 101% of principal, plus accrued and unpaid interest. The 7.375% 2021 Notes are also subject to certain covenants restricting the ability of the Company to incur additional secured debt; to enter into sale-lease back transactions; to consolidate, merge, convey or transfer substantially all of its assets; as well as other covenants and events of default that are customary for debt securities similar to the 7.375% 2021 Notes. The Company entered into interest rate locks in May 2011 to hedge the risk of changes in LIBOR until the issuance of the 7.375% 2021 Notes. The Company paid $24 million to settle those interest rate locks as of June 15, 2011. The payment was recognized in accumulated other comprehensive loss and is being amortized over the life of the 7.375% 2021 Notes.

9. CONTINGENCIES AND COMMITMENTS

Environmental

The Company periodically reviews its obligations as they relate to compliance with environmental laws, including site restoration and remediation. As of September 30, 2011, the Company had recorded liabilities of $22 million for projected environmental remediation costs. Due to the uncertainties associated with environmental assessment and remediation activities, future costs of compliance or remediation could be higher or lower than the amount currently accrued. Based on currently available information and analysis, the Company believes that it is reasonably possible that costs associated with such liabilities, or as yet unknown liabilities, may exceed current reserves in amounts that could be material but cannot be estimated as of September 30, 2011.

The Company is subject to numerous environmental laws and regulations in the jurisdictions in which it operates. The Company expenses environmental regulation compliance costs as incurred unless the underlying expenditure qualifies for capitalization under its property, plant and equipment policies. The Company faces certain risks and uncertainties related to these environmental laws and regulations, including existing and potential greenhouse gas (GHG) legislation or regulations, and actual or potential laws and regulations pertaining to water discharges, waste management (including disposal of coal combustion byproducts), and certain air emissions, such as SO_2, NO_x, particulate matter and mercury. Such risks and uncertainties could result in increased capital expenditures or other compliance costs which could have a material adverse effect on certain of our U.S. or international subsidiaries and our consolidated results of operations.

Table of Contents

Legislation and Regulation of GHG Emissions

Currently, in the United States there is no federal legislation establishing mandatory GHG emissions reduction programs (including CO_2) affecting the electric power generation facilities of the Company s subsidiaries. There are numerous state programs regulating GHG emissions from electric power generation facilities and there is a possibility that federal GHG legislation will be enacted within the next several years. Further, the United States Environmental Protection Agency (EPA) has adopted regulations pertaining to GHG emissions and has announced its intention to propose new regulations for electric generating units under Section 111 of the United States Clean Air Act (CAA).

Potential U.S. Federal GHG Legislation Federal legislation passed the U.S. House of Representatives in 2009 that, if adopted, would have imposed a nationwide cap-and-trade program to reduce GHG emissions. This legislation was never signed into law, and is no longer under consideration. In the U.S. Senate, several different draft bills pertaining to GHG legislation have been considered, including comprehensive GHG legislation similar to the legislation that passed the U.S. House of Representatives and more limited legislation focusing only on the utility and electric generation industry. It is uncertain whether any legislation pertaining to GHG emissions will be voted on and passed by the U.S. Senate and House of Representatives. If any such legislation is enacted into law, the impact could be material to the Company.

EPA GHG Regulation The EPA has promulgated regulations governing GHG emissions from automobiles under the CAA. The effect of the EPA s regulation of GHG emissions from mobile sources is that certain provisions of the CAA will also apply to GHG emissions from existing stationary sources, including many U.S. power plants. In particular, beginning January 2, 2011, construction of new stationary sources and modifications to existing stationary sources that result in increased GHG emissions became subject to permitting requirements under the prevention of significant deterioration (PSD) program of the CAA. The PSD program, as currently applicable to GHG emissions, requires sources that emit above a certain threshold of GHGs to obtain PSD permits prior to commencement of new construction or modifications to existing facilities. In addition, major sources of GHG emissions may be required to amend, or obtain new, Title V air permits under the CAA to reflect any new applicable GHG emissions requirements for new construction or for modifications to existing facilities.

The EPA promulgated a final rule on June 3, 2010 (the Tailoring Rule) that sets thresholds for GHG emissions that would trigger PSD permitting requirements. The Tailoring Rule, which became effective in January of 2011, provides that sources already subject to PSD permitting requirements need to install Best Available Control Technology (BACT) for greenhouse gases if a proposed modification would result in the increase of more than 75,000 tons per year of GHG emissions. Also, under the Tailoring Rule, any new sources of GHG emissions that would emit over 100,000 tons per year of GHG emissions, in addition to any modification that would result in GHG emissions exceeding 75,000 tons per year, require PSD review and are subject to related permitting requirements. The EPA anticipates that it will adjust downward the permitting thresholds of 100,000 tons and 75,000 tons for new sources and modifications, respectively, in future rulemaking actions. The Tailoring Rule substantially reduces the number of sources subject to PSD requirements for GHG emissions and the number of sources required to obtain Title V air permits, although new thermal power plants may still be subject to PSD and Title V requirements because annual GHG emissions from such plants typically far exceed the 100,000 ton threshold noted above. The 75,000 ton threshold for increased GHG emissions from modifications to existing sources may reduce the likelihood that future modifications to plants owned by some of our United States subsidiaries would trigger PSD requirements, although some projects that would expand capacity or electric output are likely to exceed this threshold, and in any such cases the capital expenditures necessary to comply with the PSD requirements could be significant.

In December 2010, the EPA entered into a settlement agreement with several states and environmental groups to resolve a petition for review challenging the EPA s new source performance standards (NSPS) rulemaking for electric utility steam generating units (EUSGUs) based on the NSPS s failure to address GHG emissions. Under the settlement agreement, the EPA had committed to propose GHG emissions standards for

EUSGUs by July 26, 2011. The EPA previously announced that it would delay the proposal of such standards until September 30, 2011, and it subsequently announced a further delay without specifying a deadline for the proposal of such standards. The EPA has also committed to finalize GHG NSPS for EUSGUs by May 26, 2012. The NSPS will establish GHG emission standards for newly constructed and reconstructed EUSGUs. The NSPS also will establish guidelines regarding the best system for achieving further GHG emissions reductions from existing EUSGUs. Based on the guidelines, individual states will be required to develop regulations establishing GHG performance standards for existing EUSGUs within their states. It is impossible to estimate the impact and compliance cost associated with any future NSPS applicable to EUSGUs until such regulations are finalized. However, the compliance costs could have a material and adverse impact on our consolidated financial condition or results of operations.

Regional Greenhouse Gas Initiative To date, the primary regulation of GHG emissions affecting the Company s U.S. plants has been through the Regional Greenhouse Gas Initiative (RGGI). Under RGGI, ten northeastern states have coordinated to establish rules that require reductions in CO_2 emissions from power plant operations within those states through a cap-and-trade program. States participating in RGGI in which our subsidiaries have generating facilities include Connecticut, Maryland, New York and New Jersey. Under RGGI, power plants must acquire one carbon allowance through auction or in the emission trading markets for each ton of CO_2 emitted. As noted in the Company s 2010 Form 10-K, we have estimated the costs to the Company of compliance with RGGI to be approximately $15 million for 2011.

International GHG Regulation The primary international agreement concerning GHG emissions is the Kyoto Protocol, which became effective on February 16, 2005 and requires the industrialized countries that have ratified it to significantly reduce their GHG emissions. The vast majority of the developing countries which have ratified the Kyoto Protocol have no GHG emissions reduction requirements. Many of the countries in which the Company s subsidiaries operate have no emissions reduction obligations under the Kyoto Protocol. In addition, of the 27 countries in which the Company s subsidiaries operate, all but one the United States (including Puerto Rico) have ratified the Kyoto Protocol. The first commitment period under the Kyoto Protocol is currently expected to expire at the end of 2012, and countries have been unable to agree on a successor commitment period. The next annual United Nations conference to develop a successor international agreement is scheduled for November 2011 in South Africa. It currently appears unlikely that a successor agreement will be reached at such conference; however, if a successor agreement is reached the impact could be material to the Company.

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

Other U.S. Air Emissions Regulations and Legislation

The Company s subsidiaries in the United States are subject to the Clean Air Act (CAA) and various state laws and regulations that regulate emissions of air pollutants, including SO_2, NO_X, particulate matter (PM), mercury and other hazardous air pollutants (HAPs).

The EPA promulgated the Clean Air Interstate Rule (CAIR) on March 10, 2005, which required allowance surrender for SO_2 and NO_X emissions from existing power plants located in 28 eastern states and the

Table of Contents

District of Columbia. CAIR was subsequently challenged in federal court, and on July 11, 2008, the United States Court of Appeals for the D.C. Circuit issued an opinion striking down much of CAIR and remanding it to the EPA. In response to the D.C. Circuit s opinion, on July 7, 2011, the EPA issued a final rule titled Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States, which is now referred to as the Cross-State Air Pollution Rule (CSAPR). Starting in 2012, the CSAPR requires significant reductions in SO_2 and NOx emissions from covered sources, such as power plants, in many states in which subsidiaries of the Company operate. Once fully implemented in 2014, the rule requires additional SO_2 emission reductions of 73% and additional NO_x reductions of 54% from 2005 levels. The CSAPR will be implemented, in part, through a market-based program under which compliance may be achievable through the acquisition and use of new emissions allowances that the EPA will create. The CSAPR contemplates limited interstate and intra-state trading of emissions allowances by covered sources. Initially, at least through 2012, the EPA will issue emissions allowances to affected power plants based on state emissions budgets established by the EPA under the CSAPR. The availability of and cost to purchase allowances to meet the emission reduction requirements is uncertain at this time. The CSAPR was published in the Federal Register on August 8, 2011 and on October 6, 2011, the EPA proposed some technical revisions to the CSAPR, including allowing for additional allowances for certain states. The EPA will be taking public comments on the proposed revisions for thirty days, and such public comments will be considered by the EPA prior to promulgating a final rule. Many states, utilities and other affected parties have filed lawsuits in the U.S. Court of Appeals for the District of Columbia seeking to stay the implementation of the CSAPR and challenging the validity of the CSAPR. We cannot predict the outcome of such litigation or the effect it might have on the possible implementation of the CSAPR. To comply with the CSAPR, additional pollution control technology may be required by some of our subsidiaries, and the cost of implementing any such technology could affect the financial condition or results of operations of these subsidiaries or the Company. Additionally, compliance with the CSAPR could require the purchase of newly issued allowances, the switch to higher priced, lower sulfur coal or the retirement of existing generating units. While the capital costs, other expenditures or operational restrictions necessary to comply with the CSAPR cannot be specified at this time, and the outcome of litigation pertaining to CSAPR is uncertain, the Company anticipates that the CSAPR may have a material impact on the Company s business and results of operations.

As a result of prior EPA determinations and the D.C. Circuit Court ruling, the EPA is obligated under Section 112 of the CAA to develop a rule requiring pollution controls for hazardous air pollutants, including mercury, hydrogen chloride, hydrogen fluoride, and other metal species from coal and oil-fired power plants. The EPA has entered into a consent decree under which it is obligated to finalize the rule by November 2011, and it has subsequently requested an extension of this deadline until December 16, 2011. In connection with such rule, the CAA requires the EPA to establish maximum achievable control technology (MACT) standards for each pollutant regulated under the rule. MACT is defined as the emission limitation achieved by the best performing 12% of sources in the source category. The EPA published a proposed rule on May 3, 2011 that would establish national emissions standards for hazardous air pollutants (NESHAP) from coal and oil-fired electric utility steam generating units. The rule, as currently proposed, may require all coal-fired power plants to retire operations or install acid gas control technology, upgrade particulate control devices and/or install some other type of mercury control technology, such as sorbent injection. The public comment period for this proposed rule has expired, and the public comments will be considered by the EPA prior to promulgating a final rule. Most of the United States coal-fired plants operated by the Company s subsidiaries have acid gas scrubbers or comparable control technologies, but as proposed there are other improvements to such control technologies that may be needed at some of the Company s plants. Under the CAA, compliance is required within three years of the effective date of the rule; however, the compliance period for a unit, or group of units, may be extended by state permitting authorities (for one additional year) or through a determination by the President (for up to two additional years). At this time, the Company cannot predict the extent of the final regulations for hazardous air pollutants, but the cost of compliance with any such regulations could be material.

Other International Air Emissions Regulations and Legislation

On January 18, 2011, the President of Chile approved a new air emissions regulation submitted to him by the national environmental regulatory agency (CONAMA). The new regulation establishes limits on emissions of NO_X, SO_2, metals and particulate matter for both existing and new thermal power plants, with more stringent limitations on new facilities. The regulation became effective on June 23, 2011. The regulation will require AES Gener, the Company s Chilean subsidiary, to install emissions reduction equipment at its existing thermal plants from late 2011 through 2015. The costs of compliance with such regulation have not yet been determined and the Company believes some of the compliance costs are contractually passed through to counterparties. However, the compliance costs could be material.

Cooling Water Intake Regulations

The Company s U.S. facilities are subject to the U.S. Clean Water Act Section 316(b) rule issued by the EPA which seeks to protect fish and other aquatic organisms by requiring existing steam electric generating facilities to utilize the best technology available for cooling water intake structures. The EPA published a proposed rule establishing requirements under 316(b) regulations on April 20, 2011. The proposal, based on Section 316(b) of the U.S. Clean Water Act, establishes Best Technology Available (BTA) requirements regarding impingement standards with respect to aquatic organisms for all facilities that withdraw above 2 million gallons per day of water from certain water bodies and utilize at least 25% of the withdrawn water for cooling purposes. To meet these BTA requirements, as currently proposed, cooling water intake structures associated with once through cooling processes will need modifications of existing traveling screens that protect aquatic organisms and will need to add a fish return and handling system for each cooling system. Existing closed cycle cooling facilities may require upgrades to water intake structure systems. The proposal would also require comprehensive site-specific studies during the permitting process and may require closed-cycle cooling systems in order to meet BTA entrainment standards.

The public comment period for this proposed rule has expired, and the EPA will consider the public comments with a view to issuing a final rule by July of 2012. 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 protecting fish and other aquatic organisms 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. On September 27, 2010, the California Office of Administrative Law approved a policy adopted by the California Water Resources Control Board with respect to power plant cooling water intake structures. This policy became effective on October 1, 2010, and establishes technology-based standards to implement Section 316(b) of the U.S. Clean Water Act. At this time, it is contemplated that the Company s Redondo Beach, Huntington Beach and Alamitos power plants in California will need to have in place best technology available by December 31, 2020, or repower the facilities. 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, many of the Company s facilities generate coal combustion byproducts (CCB), including fly ash, requiring disposal or processing. On June 21, 2010 the EPA published in the Federal Register a proposed rule to regulate CCB under the Resource Conservation and Recovery Act (RCRA). The proposed rule provides two possible options for CCB regulation, and both options contemplate heightened structural integrity requirements for surface impoundments of CCB. The first option contemplates regulation of CCB as a hazardous waste subject to regulation under Subtitle C of the RCRA. Under this option, existing surface impoundments containing CCB would be required to be retrofitted with composite liners and these impoundments would likely be phased out over several years. State and/or federal permit programs would be developed for storage, transport and disposal of CCB. States could bring enforcement actions for non-compliance with permitting requirements, and the EPA would have oversight responsibilities as well as the authority to bring lawsuits for non-compliance. The second option contemplates regulation of CCB under Subtitle D of the RCRA. Under this option, the EPA would create national criteria applicable to CCB landfills and surface impoundments. Existing impoundments would also be required to be retrofitted with composite liners and would likely be phased out over several years. This option would not contain federal or state permitting requirements. The primary enforcement mechanism under regulation pursuant to Subtitle D would be private lawsuits.

The public comment period for this proposed regulation has expired, and the EPA is required to consider the public comments prior to promulgating a final rule. Requirements under a final rule are expected to become effective by January 2012, with a compliance schedule of five years. While the exact impact and compliance cost associated with future regulations of CCB cannot be established until such regulations are finalized, there can be no assurance that the Company s businesses, financial condition or results of operations would not be materially and adversely affected by such regulations.

Indiana Senate Bill 251

In May 2011, Senate Bill 251 became a law in the State of Indiana. Senate Bill 251 is a comprehensive bill which, among other things, provides Indiana utilities, including IPL, with a means for recovering 80% of costs incurred to comply with federal mandates through a periodic retail rate adjustment mechanism, and additional cost recovery is possible through a subsequent general rate case. This includes costs to comply with regulations from the EPA, FERC, NERC, the Department of Energy, etc., including capital intensive requirements and/or proposals such as those relating to cooling water intake regulations, waste management and coal combustion byproducts, wastewater effluent, MISO transmission expansion costs and polychlorinated biphenyls. It does not change existing legislation that allows for 100% recovery of clean coal technology designed to reduce air pollutants (Indiana Senate Bill 29).

Some of the most important features of Senate Bill 251 to IPL are as follows: any energy utility in Indiana seeking to recover federally mandated costs incurred in connection with a compliance project shall apply to the Indiana Utility Regulatory Commission (IURC) for a certificate of public convenience and necessity (CPCN) for the compliance project. It sets forth certain factors that the IURC must consider in determining whether to grant a CPCN. It further specifies that if the IURC approves a proposed compliance project and the projected federally mandated costs associated with the project, the following apply: (i) 80% of the approved costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism; (ii) 20% of the approved costs shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the IURC; and (iii) actual costs exceeding the projected federally mandated costs of the approved compliance project by more than 25% shall require specific justification and approval by the IURC before being authorized in the energy utility s next general rate case.

Guarantees, Letters of Credit and Commitments

In connection with certain project financing, acquisition, power purchase, and other agreements, AES has expressly undertaken limited obligations and commitments, most of which will only be effective or will be terminated upon the occurrence of future events. In the normal course of business, AES has entered into various agreements, mainly guarantees and letters of credit, to provide financial or performance assurance to third parties on behalf of AES businesses. These agreements are entered into primarily to support or enhance the creditworthiness otherwise achieved by a business on a stand-alone basis, thereby facilitating the availability of sufficient credit to accomplish their intended business purposes. Most of the contingent obligations primarily relate to future performance commitments which the Company or its businesses expect to fulfill within the normal course of business. The expiration dates of these guarantees vary from less than one year to more than 15 years.

The following table summarizes the Parent Company s contingent contractual obligations as of September 30, 2011. Amounts presented in the table below represent the Parent Company s current undiscounted exposure to guarantees and the range of maximum undiscounted potential exposure. The maximum exposure is not reduced by the amounts, if any, that could be recovered under the recourse or collateralization provisions in the guarantees. The amounts include obligations made by the Parent Company for the direct benefit of the lenders associated with the non-recourse debt of businesses of $26 million.

Contingent contractual obligations	Amount (in millions)	Number of Agreements	Maximum Exposure Range for Each Agreement (in millions)
Guarantees	$ 357	23	<$1 - $53
Letters of credit under the senior secured credit facility	12	11	<$1 - $7
Cash collateralized letters of credit	260	13	<$1 - $223
Total	$ 629	47	

As of September 30, 2011, the Company had $16 million of commitments to invest in subsidiaries under construction and to purchase related equipment that were not included in the letters of credit discussed above. The Company expects to fund these net investment commitments in 2011. The exact payment schedules will be dictated by the construction milestones. Additionally, subject to regulatory approvals, the Company is committed to purchase DPL for $3.5 billion, see Note 17 *Acquisitions* for further information. We expect to fund these commitments from a combination of current liquidity and internally generated Parent Company cash flow.

Litigation

The Company is involved in certain claims, suits and legal proceedings in the normal course of business, some of which are described below. The Company has accrued for litigation and claims where it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. The Company has evaluated claims in accordance with the accounting guidance for contingencies that it deems both probable and reasonably estimable and accordingly, has recorded aggregate reserves for all claims of approximately $372 million and $448 million as of September 30, 2011 and December 31, 2010, respectively. These reserves are reported on the condensed consolidated balance sheets within accrued and other liabilities and other long-term liabilities. A significant portion of the reserves relate to employment, non-income tax and customer disputes in international jurisdictions, principally Brazil. Certain of the Company s subsidiaries, principally in Brazil, are defendants in a number of labor and employment lawsuits. The complaints generally seek unspecified monetary damages, injunctive relief, or other relief. The subsidiaries have denied any liability and intend to vigorously defend themselves in all of these proceedings. There can be no assurance that these reserves will be adequate to cover all existing and future claims or that we will have the liquidity to pay such claims as they arise.

The Company believes, based upon information it currently possesses and taking into account established reserves for liabilities and its insurance coverage, that the ultimate outcome of these proceedings and actions is unlikely to have a material effect on the Company s financial statements. However, even where no reserve has been recognized, it is reasonably possible that some matters could be decided unfavorably to the Company and could require the Company to pay damages or make expenditures in amounts that could be material but could not be estimated as of September 30, 2011. The material contingencies where a loss is reasonably possible are described below. In aggregate, the Company estimates that the range of potential losses related to these material contingences to be up to $1.2 billion. The amounts considered reasonably possible do not include amounts reserved, as discussed above. Where a loss or range of loss cannot be estimated, a statement to this effect has been included in the applicable case descriptions presented below.

In 1989, Centrais Elétricas Brasileiras S.A. (Eletrobrás) filed suit in the Fifth District Court in the State of Rio de Janeiro against Eletropaulo Eletricidade de São Paulo S.A. (EEDSP) relating to the methodology for calculating monetary adjustments under the parties financing agreement. In April 1999, the Fifth District Court found for Eletrobrás and in September 2001, Eletrobrás initiated an execution suit in the Fifth District Court to collect approximately R$1.2 billion ($656 million) from Eletropaulo (as estimated by Eletropaulo) and a lesser amount from an unrelated company, Companhia de Transmissão de Energia Elétrica Paulista (CTEEP) (Eletropaulo and CTEEP were spun off from EEDSP pursuant to its privatization in 1998). In November 2002, the Fifth District Court rejected Eletropaulo s defenses in the execution suit. Eletropaulo appealed and in September 2003, the Appellate Court of the State of Rio de Janeiro (AC) ruled that Eletropaulo was not a proper party to the litigation because any alleged liability had been transferred to CTEEP pursuant to the privatization. In June 2006, the Superior Court of Justice (SCJ) reversed the Appellate Court s decision and remanded the case to the Fifth District Court for further proceedings, holding that Eletropaulo s liability, if any, should be determined by the Fifth District Court. Eletropaulo s subsequent appeals to the Special Court (the highest court within the SCJ) and the Supreme Court of Brazil were dismissed. Eletrobrás later requested that the amount of Eletropaulo s alleged debt be determined by an accounting expert appointed by the Fifth District Court. Eletropaulo consented to the appointment of such an expert, subject to a reservation of rights. In February 2010, the Fifth District Court appointed an accounting expert to determine the amount of the alleged debt and the responsibility for its payment in light of the privatization, in accordance with the methodology proposed by Eletrobrás. Pursuant to its reservation of rights, Eletropaulo filed an interlocutory appeal with the AC asserting that the expert was required to determine the issues in accordance with the methodology proposed by Eletropaulo, and that Eletropaulo should be entitled to take discovery and present arguments on the issues to be determined by the expert. In April 2010, the AC issued a decision agreeing with Eletropaulo s arguments and directing the Fifth District Court to proceed accordingly. Eletrobrás has restarted the accounting proceedings at the Fifth District Court, which will proceed in accordance with the AC s April 2010 decision. The parties are briefing the issues. In the Fifth District Court proceedings, the expert s conclusions will be subject to the Fifth District Court s review and approval. If Eletropaulo is determined to be responsible for the debt, after the amount of the alleged debt is determined, Eletrobrás will be entitled to resume the execution suit in the Fifth District Court at any time. If Eletrobrás does so, Eletropaulo will be required to provide security in the amount of its alleged liability. In that case, if Eletrobrás requests the seizure of such security and the Fifth District Court grants such request, Eletropaulo s results of operations may be materially adversely affected and, in turn the Company s results of operations could be materially adversely affected. In addition, in February 2008, CTEEP filed a lawsuit in the Fifth District Court against Eletrobrás and Eletropaulo seeking a declaration that CTEEP is not liable for any debt under the financing agreement. The parties are disputing the proper venue for the CTEEP lawsuit. Eletropaulo believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In August 2001, the Grid Corporation of Orissa, India, now Gridco Ltd. (Gridco), filed a petition against the Central Electricity Supply Company of Orissa Ltd. (CESCO), an affiliate of the Company, with the Orissa Electricity Regulatory Commission (OERC), alleging that CESCO had defaulted on its obligations as an OERC-licensed distribution company, that CESCO management abandoned the management of CESCO, and seeking interim measures of protection, including the appointment of an administrator to manage CESCO. Gridco, a state-owned entity, is the sole wholesale energy provider to CESCO. Pursuant to the OERC s August 2001 order, the management of CESCO was replaced with a government administrator who was appointed by the OERC. The OERC later held that the Company and other CESCO shareholders were not necessary or proper parties to the OERC proceeding. In August 2004, the OERC issued a notice to CESCO, the Company and others giving the recipients of the notice until November 2004 to show cause why CESCO s distribution license should not be revoked. In response, CESCO submitted a business plan to the OERC. In February 2005, the OERC issued an order rejecting the proposed business plan. The order also stated that the CESCO distribution license would be revoked if an acceptable business plan for CESCO was not submitted to and approved by the OERC prior to March 31, 2005. In its April 2, 2005 order, the OERC revoked the CESCO distribution license. CESCO has filed an appeal against the April 2, 2005 OERC order and that appeal remains pending in the Indian courts. In addition, Gridco asserted that a comfort letter issued by the Company in connection with the Company s indirect investment in CESCO obligates the Company to provide additional financial support to cover all of CESCO s financial obligations to Gridco. In December 2001, Gridco served a notice to arbitrate pursuant to the Indian Arbitration and Conciliation Act of 1996 on the Company, AES Orissa

Distribution Private Limited (AES ODPL), and Jyoti Structures (Jyoti) pursuant to the terms of the CESCO Shareholders Agreement between Gridco, the Company, AES ODPL, Jyoti and CESCO (the CESCO arbitration). In the arbitration, Gridco appeared to be seeking approximately $189 million in damages, plus undisclosed penalties and interest, but a detailed alleged damage analysis was not filed by Gridco. The Company counterclaimed against Gridco for damages. In June 2007, a 2-to-1 majority of the arbitral tribunal rendered its award rejecting Gridco s claims and holding that none of the respondents, the Company, AES ODPL, or Jyoti, had any liability to Gridco. The respondents counterclaims were also rejected. In September 2007, Gridco filed a challenge of the arbitration award with the local Indian court. In June 2008, Gridco filed a separate application with the local Indian court for an order enjoining the Company from selling or otherwise transferring its shares in Orissa Power Generation Corporation Ltd. (OPGC), an equity method investment of the Company, and requiring the Company to provide security in the amount of the contested damages in the CESCO arbitration until Gridco s challenge to the arbitration award is resolved. In June 2010, a 2-to-1 majority of the arbitral tribunal awarded the Company some of its costs relating to the arbitration. In August 2010, Gridco filed a challenge of the cost award with the local Indian court. The Company believes that it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In March 2003, the office of the Federal Public Prosecutor for the State of São Paulo, Brazil (MPF) notified AES Eletropaulo that it had commenced an inquiry related to the BNDES financings provided to AES Elpa and AES Transgás and the rationing loan provided to Eletropaulo, changes in the control of Eletropaulo, sales of assets by Eletropaulo and the quality of service provided by Eletropaulo to its customers, and requested various documents from Eletropaulo relating to these matters. In July 2004, the MPF filed a public civil lawsuit in the Federal Court of São Paulo (FSCP) alleging that BNDES violated Law 8429/92 (the Administrative Misconduct Act) and BNDES s internal rules by: (1) approving the AES Elpa and AES Transgás loans; (2) extending the payment terms on the AES Elpa and AES Transgás loans; (3) authorizing the sale of Eletropaulo s preferred shares at a stock-market auction; (4) accepting Eletropaulo s preferred shares to secure the loan provided to Eletropaulo; and (5) allowing the restructurings of Light Serviços de Eletricidade S.A. and Eletropaulo. The MPF also named AES Elpa and AES Transgás as defendants in the lawsuit because they allegedly benefited from BNDES s alleged violations. In May 2006, the FCSP ruled that the MPF could pursue its claims based on the first, second, and fourth alleged violations noted above. The MPF subsequently filed an interlocutory appeal with the Federal Court of Appeals (FCA) seeking to require the FCSP to consider all five alleged violations. Also, in July 2006, AES Elpa and AES Transgás filed an interlocutory appeal with the FCA, which was subsequently consolidated with the MPF s interlocutory appeal, seeking a transfer of venue and to enjoin the FCSP from considering any of the alleged violations. In June 2009, the FCA granted the injunction sought by AES Elpa and AES Transgás and transferred the case to the Federal Court of Rio de Janeiro. In May 2010, the MPF filed an appeal with the Superior Court of Justice challenging the transfer. The MPF s lawsuit before the FCSP has been stayed pending a final decision on the interlocutory appeals. AES Elpa and AES Brasiliana (the successor of AES Transgás) believe they have meritorious defenses to the allegations asserted against them and will defend themselves vigorously in these proceedings; however, there can be no assurances that they will be successful in their efforts.

In April 2009, the Antimonopoly Agency initiated an investigation of the power sales of Ust-Kamenogorsk HPP (UK HPP) and Shulbinsk HPP, hydroelectric plants under AES concession (collectively, the Hydros), for the period from January through February 2009. The investigation of both Hydros has now been completed. The Antimonopoly Agency determined that the Hydros abused their market position and charged monopolistically high prices for power from January through February 2009. The Agency sought an order from the administrative court requiring UK HPP to pay an administrative fine of approximately KZT 120 million ($1 million) and to disgorge profits for the period at issue, estimated by the Antimonopoly Agency to be approximately KZT 440 million ($3 million). No fines or damages have been paid to date, however, as the proceedings in the administrative court have been suspended due to the initiation of related criminal proceedings against officials of the Hydros. In the course of criminal proceedings, the financial police have expanded the periods at issue to the entirety of 2009 in the case of UK HPP and from January through October 2009 in the case

Table of Contents

of Shulbinsk HPP, and sought increased damages of KZT 1.2 billion ($8 million) in the case of UK HPP and KZT 1.3 billion ($9 million) in the case of Shulbinsk HPP. The Hydros believe they have meritorious defenses and will assert them vigorously in these proceedings; however, there can be no assurances that they will be successful in their efforts.

In July 1993, the Public Attorney s office filed a claim against Eletropaulo, the Sao Paulo State Government, SABESP (a state-owned company), CETESB (the Environmental Agency of Sao Paulo State) and DAEE (the Municipal Water and Electric Energy Department) alleging that they were liable for pollution of the Billings Reservoir as a result of pumping water from the Pinheiros River into the Billings Reservoir. The events in question occurred while Eletropaulo was a state-owned company. An initial lower court decision in 2007 found the parties liable for the payment of approximately R$760 million ($415 million) for remediation. Eletropaulo subsequently appealed the decision to the Appellate Court of the State of Sao Paulo, which reversed the lower court decision. In 2009, the Public Attorney s Office filed appeals to both the Superior Court of Justice and the Supreme Court and such appeals were answered by Eletropaulo in the fourth quarter of 2009. Eletropaulo believes it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

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

On February 2, 2009, the Cayuga facility received a Notice of Violation from the New York State Department of Environmental Conservation (NYSDEC) that the facility had exceeded the permitted volume limit of coal ash that can be disposed of in the on-site landfill. Cayuga has met with NYSDEC and submitted a Landfill Liner Demonstration Report to them. Such report found that the landfill has adequate engineering integrity to support the additional coal ash and there is no inherent environmental threat. NYSDEC has indicated they accept the finding of the report. A permit modification was approved by the NYSDEC on May 14, 2010 and such permit modification allows for closure of this approximately 10-acre portion of the landfill. The construction in accordance with the approved permit modification was completed in November 2010 and the certification report for this construction project was submitted to the NYSDEC in the second quarter of 2011. While at this time it is not possible to predict what impact, if any, this matter may have on the Company, its results of operations or its financial position, based upon the discussions to date, the Company does not believe the impact will be material.

In July 2009, AES Energía Cartagena S.R.L. (AES Cartagena) received notices from the Spanish national energy regulator, Comisión Nacional de Energía (CNE), stating that the proceeds of the sale of electricity from AES Cartagena s plant should be reduced by roughly the value of the CO_2 allowances that were granted to AES Cartagena for free for the years 2007, 2008, and the first half of 2009. In particular, the notices stated that CNE intended to invoice AES Cartagena to recover that value, which CNE calculated as approximately 20 million ($27 million) for 2007-2008 and an amount to be determined for the first half of 2009. In September 2009, AES Cartagena received invoices for 523,548 (approximately $712,000) for the allowances granted for free for 2007 and 19,907,248 (approximately $27 million) for 2008. In July 2010, AES Cartagena received an invoice for approximately 5 million ($7 million) for the allowances granted for free for the first half of 2009. AES Cartagena does not expect to be charged for CO_2 allowances issued free of charge for subsequent periods. AES Cartagena has paid the amounts invoiced and has filed challenges to the CNE s demands in the Spanish judicial system. There can be no assurances that the challenges will be successful. AES Cartagena has demanded indemnification from its fuel supply and electricity toller, GDF Suez S.A. (GDFS), in relation to the CNE

Table of Contents

invoices under the long-term energy agreement (the Energy Agreement) with GDFS. However, GDFS has disputed that it is responsible for the CNE invoices under the Energy Agreement. Therefore, in September 2009, AES Cartagena initiated arbitration against GDFS, seeking to recover the payments made to CNE. In the arbitration, AES Cartagena also seeks a determination that GDFS is responsible for procuring and bearing the cost of CO_2 allowances that are required to offset the CO_2 emissions of AES Cartagena s power plant, which is also in dispute between the parties. To date, AES Cartagena has paid approximately 25 million ($34 million) for the CO_2 allowances that have been required to offset 2008, 2009 and 2010 CO_2 emissions. AES Cartagena expects that allowances will need to be purchased to offset emissions for subsequent years. The evidentiary hearing in the arbitration took place from May 31-June 4, 2010, and closing arguments were heard on September 1, 2010. In February 2011, the arbitral tribunal requested further briefing on certain issues in the arbitration, which was later submitted by the parties. The tribunal has the matter under consideration. If AES Cartagena does not prevail in the arbitration and is required to bear the cost of carbon compliance, its results of operations could be materially adversely affected and, in turn, there could be a material adverse effect on the Company and its results of operations. AES Cartagena believes it has meritorious claims and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts. The parties have agreed to settle the dispute subject to the closing of a share sale agreement, which is subject to regulatory and lender approvals. See Note 20 *Subsequent Events* for further information. If the transaction does not close, the arbitration will continue, including the risks described above.

In November 2009, April 2010, December 2010, April 2011, June 2011, and August 2011, substantially similar personal injury lawsuits were filed by a total of 47 residents and decedent estates in the Dominican Republic against the Company, AES Atlantis, Inc., AES Puerto Rico, LP, AES Puerto Rico, Inc., and AES Puerto Rico Services, Inc., in the Superior Court for the State of Delaware. In each lawsuit the plaintiffs allege that the coal combustion byproducts of AES Puerto Rico s power plant were illegally placed in the Dominican Republic from October 2003 through March 2004 and subsequently caused the plaintiffs birth defects, other personal injuries, and/or deaths. The plaintiffs did not quantify their alleged damages, but generally alleged that they are entitled to compensatory and punitive damages. The AES defendants moved for partial dismissal of both the November 2009 and April 2010 lawsuits on various grounds. In July 2011, the Superior Court dismissed the plaintiffs international law and punitive damages claims, but held that the plaintiffs had stated intentional tort, negligence, and strict liability claims under Dominican law, which the Superior Court found governed the lawsuits. The Superior Court granted the plaintiffs leave to amend their complaints in accordance with its decision, and in September 2011, the plaintiffs in the November 2009 and April 2010 lawsuits did so. The AES defendants will respond to those amended complaints by October 31, 2011. The AES defendants will also respond to the December 2010, April 2011, June 2011 and August 2011 lawsuits after the relevant plaintiffs file amended complaints. The AES defendants believe they have meritorious defenses to the claims asserted against them and will defend themselves vigorously; however, there can be no assurances that they will be successful in their efforts.

On December 21, 2010, AES-3C Maritza East 1 EOOD, which owns an unfinished 670 MW lignite-fired power plant in Bulgaria, made the first in a series of demands on the performance bond securing the construction Contractor s obligations under the parties EPC Contract. The Contractor failed to complete the plant on schedule. The total amount demanded by Maritza under the performance bond was approximately 155 million ($211 million). The Contractor obtained an injunction from a lower French court purportedly preventing the issuing bank from honoring the bond demands. However, the Versailles Court of Appeal canceled the injunction in July 2011, and therefore the issuing bank paid the bond demands in full. The Contractor may attempt to seek relief relating to the bond dispute in the French or English courts. In addition, in December 2010, the Contractor stopped commissioning of the power plant s two units because of the alleged characteristics of the lignite supplied to it for commissioning. In January 2011, the Contractor initiated arbitration on its lignite claim, seeking an extension of time to complete the power plant, an increase to the contract price, and other relief, including in relation to the bond demands. The Contractor later added claims relating to the alleged unavailability of the grid during commissioning. Maritza rejected the Contractor s claims and asserted counterclaims for delay liquidated damages and other relief relating to the Contractor s failure to complete the power plant and other breaches of the

Table of Contents

EPC Contract. Maritza also terminated the EPC Contract for cause and asserted arbitration claims against the Contractor relating to the termination. The Contractor asserted counterclaims relating to the termination. The Contractor is seeking approximately 240 million ($326 million) in the arbitration, unspecified damages for alleged injury to reputation, and other relief. The arbitral hearing on the merits is in September 2012. Maritza believes it has meritorious claims and defenses and will assert them vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

10. PENSION PLANS

Total pension cost for the three and nine months ended September 30, 2011 and 2010 included the following components:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011		2010		2011		2010	
	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign
	(in millions)				(in millions)			
Service cost	$ 1	$ 6	$ 1	$ 3	$ 5	$ 16	$ 4	$ 12
Interest cost	8	145	8	129	24	436	24	380
Expected return on plan assets	(8)	(130)	(7)	(108)	(24)	(391)	(22)	(318)
Amortization of prior service cost	1	-	1	-	3	-	3	-
Amortization of net loss	3	6	3	4	10	18	9	11
Loss on curtailment	-	-	-	-	-	4	-	-
Total pension cost	$ 5	$ 27	$ 6	$ 28	$ 18	$ 83	$ 18	$ 85

Total employer contributions for the nine months ended September 30, 2011 for the Company s U.S. and foreign subsidiaries were $30 million and $132 million, respectively. The expected remaining scheduled employer contributions for 2011 are $7 million for U.S. subsidiaries and $39 million for foreign subsidiaries.

11. EQUITY

STOCK REPURCHASE PROGRAM

In July 2010, the Company s Board of Directors approved a stock repurchase program (the Program) under which the Company can repurchase up to $500 million of AES common stock. The Board authorization permits the Company to repurchase stock through a variety of methods, including open market repurchases and/or privately negotiated transactions. There can be no assurances as to the amount, timing or prices of repurchases, which may vary based on market conditions and other factors. The Program does not have an expiration date and it can be modified or terminated by the Board of Directors at any time. During the nine months ended September 30, 2011, shares of common stock repurchased under this plan totaled 19,987,795 at a total cost of $224 million plus a nominal amount of commissions (average of $11.24 per share including commissions), bringing the cumulative total purchases under the program to 28,370,620 shares at a total cost of $324 million plus a nominal amount of commissions (average of $11.42 per share including commissions).

The shares of stock repurchased have been classified as treasury stock and accounted for using the cost method. A total of 36,832,776 and 17,287,073 shares were held as treasury stock at September 30, 2011 and December 31, 2010, respectively. The Company has not retired any shares held in treasury during the nine months ended September 30, 2011.

Table of Contents

COMPREHENSIVE INCOME

The components of comprehensive income (loss) for the three and nine months ended September 30, 2011 and 2010 were as follows:

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions)		(in millions)	
Net income	$ 175	$ 397	$ 1,085	$ 1,228
Change in fair value of available-for-sale securities, net of income tax benefit of $0, $0, $1 and $4, respectively	(1)	-	(3)	(6)
Foreign currency translation adjustments, net of income tax benefit (expense) of $42, $(15), $28 and $(7), respectively	(589)	285	(327)	519
Derivative activity:				
Reclassification to earnings, net of income tax (expense) of $(13), $(3), $(15) and $(22), respectively	53	13	112	81
Change in derivative fair value, net of income tax benefit of $68, $23, $93 and $82, respectively	(236)	(99)	(305)	(336)
Total net change in fair value of derivatives	(183)	(86)	(193)	(255)
Change in unfunded pension obligation, net of income tax (expense) of $(2), $(1), $(6) and $(3), respectively	5	1	12	6
Other comprehensive income (loss)	(768)	200	(511)	264
Comprehensive income (loss)	(593)	597	574	1,492
Less: Comprehensive (income) loss attributable to noncontrolling interests[(1)]	12	(385)	(651)	(789)
Comprehensive income (loss) attributable to The AES Corporation	$ (581)	$ 212	$ (77)	$ 703

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

The components of accumulated other comprehensive loss as of September 30, 2011 and December 31, 2010 were as follows:

	September 30, 2011	December 31, 2010
	(in millions)	
Foreign currency translation adjustment	$ 2,002	$ 1,824
Unrealized derivative losses, net	511	344
Unfunded pension obligation	212	216
Securities available-for-sale	2	(1)
Accumulated other comprehensive loss	$ 2,727	$ 2,383

EQUITY TRANSACTIONS WITH NONCONTROLLING INTERESTS

On July 7, 2011, a subsidiary of the Company completed the acquisition of an additional 10% equity interest in AES-VCM Mong Duong Power Company Limited (Mong Duong), a 1,200 MW coal-fired power plant in development in the Quang Ninh province in Vietnam, from Vietnam National Coal and Mineral Industries Group, its minority shareholder. On July 8, 2011, through a subsidiary, the Company sold 30% and 19% equity interests in Mong Duong to PSC Energy Global Co., Ltd. (a wholly owned subsidiary of POSCO Corporation) and Stable Investment

Corporation (a wholly owned subsidiary of China Investment Corporation, a related party) respectively, resulting in the Company retaining a 51% indirect equity interest in Mong Duong. As a result of these transactions, the Company did not lose control of Mong Duong, which continues to be accounted for as a consolidated subsidiary. A net gain of $19 million resulting from these transactions was recorded as an equity transaction in additional paid-in capital.

The following table summarizes the net income attributable to The AES Corporation and transfers (to) from noncontrolling interests for the three and nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Net (loss) income attributable to The AES Corporation	$ (131)	$ 114	$ 267	$ 445
Transfers (to) from the noncontrolling interests:				
Net increase in The AES Corporation s paid-in capital for sale of subsidiary shares	19	-	19	-
Net transfers (to) from noncontrolling interest	19	-	19	-
Change from net income attributable to The AES Corporation and transfers (to) from noncontrolling interests	$ (112)	$ 114	$ 286	$ 445

12. SEGMENTS

The Company s current management reporting structure is organized along our two lines of business (Generation and Utilities) and three regions: (1) Latin America & Africa; (2) North America; and (3) Europe, Middle East & Asia (collectively EMEA), each managed by a regional president. The segment reporting structure uses the Company s management reporting structure as its foundation to reflect how the Company manages the business internally. On September 6, 2011, the Company announced the appointment of Andrés Gluski as its President and Chief Executive Officer. Subsequently, on October 18, 2011, the Company announced a plan to redefine its operational management and organizational structure. The planned reporting structure will remain organized along two lines of business Generation and Utilities, however, we are continuing to evaluate both the timing and impact, if any, that the realignment will have on our reportable segments. For the three and nine months ended September 30, 2011 the Company applied the segment reporting accounting guidance, which provides certain quantitative thresholds and aggregation criteria, and concluded it has the following six reportable segments:

Latin America Generation;

Latin America Utilities;

North America Generation;

North America Utilities;

Europe Generation; and

Asia Generation.

Corporate and Other The Company s Europe Utilities, Africa Utilities, Africa Generation, Wind Generation operating segments and other climate solutions and renewables projects are reported within Corporate and Other because they do not meet the criteria to allow for aggregation with another operating segment or the quantitative thresholds that would require separate disclosure under segment reporting accounting guidance. None of these operating segments are currently material to our presentation of reportable segments, individually or in the aggregate. AES Solar and certain other unconsolidated businesses are accounted for using the equity method of accounting;

Table of Contents

therefore, their operating results are included in Net Equity in Earnings of Affiliates on the face of the Consolidated Statements of Operations, not in revenue or gross margin. Corporate and Other also includes costs related to corporate overhead costs which are not directly associated with the operations of our six reportable segments and other intercompany charges such as self-insurance premiums which are fully eliminated in consolidation.

The Company uses Adjusted Gross Margin, a non-GAAP measure, to evaluate the performance of its segments. Adjusted Gross Margin is defined by the Company as: Gross Margin plus depreciation and amortization less general and administrative expenses.

Segment revenue includes inter-segment sales related to the transfer of electricity from generation plants to utilities within Latin America. No material inter-segment revenue relationships exist between other segments. Corporate allocations include certain self insurance activities which are reflected within segment Adjusted Gross Margin. All intra-segment activity has been eliminated with respect to revenue and Adjusted Gross Margin within the segment. Inter-segment activity has been eliminated within the total consolidated results. All balance sheet information for businesses that were discontinued or classified as held for sale as of September 30, 2011 is segregated and is shown in the line Discontinued Businesses in the accompanying segment tables.

Information about the Company s operations by segment for the three and nine months ended September 30, 2011 and 2010 was as follows:

Three Months Ended	**Total Revenue**		**Intersegment**		**External Revenue**	
September 30,	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
			(in millions)			
Latin America Generation	$ 1,302	$ 1,111	$ (328)	$ (267)	$ 974	$ 844
Latin America Utilities	1,930	1,757	-	-	1,930	1,757
North America Generation	372	413	-	-	372	413
North America Utilities	321	306	-	-	321	306
Europe Generation	397	282	-	-	397	282
Asia Generation	172	136	-	-	172	136
Corp/Other & eliminations	(113)	(15)	328	267	215	252
Total Revenue	$ 4,381	$ 3,990	$ -	$ -	$ 4,381	$ 3,990

Nine Months Ended	**Total Revenue**		**Intersegment**		**External Revenue**	
September 30,	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
			(in millions)			
Latin America Generation	$ 3,810	$ 3,178	$ (842)	$ (778)	$ 2,968	$ 2,400
Latin America Utilities	5,774	5,236	-	-	5,774	5,236
North America Generation	1,116	1,173	(4)	-	1,112	1,173
North America Utilities	890	869	-	-	890	869
Europe Generation	1,125	864	(1)	-	1,124	864
Asia Generation	449	491	-	-	449	491
Corp/Other & eliminations	(47)	(34)	847	778	800	744
Total Revenue	$ 13,117	$ 11,777	$ -	$ -	$ 13,117	$ 11,777

Table of Contents

Three Months Ended September 30,	Total Adjusted Gross Margin 2011	Total Adjusted Gross Margin 2010	Intersegment 2011	Intersegment 2010	External Adjusted Gross Margin 2011	External Adjusted Gross Margin 2010
			(in millions)			
Latin America Generation	$ 505	$ 436	$ (313)	$ (262)	$ 192	$ 174
Latin America Utilities	378	306	322	267	700	573
North America Generation	145	146	3	5	148	151
North America Utilities	113	118	-	-	113	118
Europe Generation	128	71	2	2	130	73
Asia Generation	35	51	-	1	35	52
Corp/Other & eliminations	(62)	12	(14)	(13)	(76)	(1)
Reconciliation to Income from Continuing Operations before Taxes						
Depreciation and amortization					(313)	(271)
Interest expense					(432)	(381)
Interest income					103	96
Other expense					(76)	(23)
Other income					58	17
Goodwill impairment					(17)	(18)
Asset impairment expense					(163)	(296)
Foreign currency transaction (losses) gains on net monetary position					(92)	103
Other non-operating expense					(82)	(2)
Income from continuing operations before taxes and equity in earnings of affiliates					$ 228	$ 365

Nine Months Ended September 30,	Total Adjusted Gross Margin 2011	Total Adjusted Gross Margin 2010	Intersegment 2011	Intersegment 2010	External Adjusted Gross Margin 2011	External Adjusted Gross Margin 2010
			(in millions)			
Latin America Generation	$ 1,493	$ 1,296	$ (800)	$ (766)	$ 693	$ 530
Latin America Utilities	1,035	888	820	778	1,855	1,666
North America Generation	402	406	6	12	408	418
North America Utilities	292	324	1	1	293	325
Europe Generation	327	287	4	5	331	292
Asia Generation	133	204	1	3	134	207
Corp/Other & eliminations	(37)	19	(32)	(33)	(69)	(14)
Reconciliation to Income from Continuing Operations before Taxes						
Depreciation and amortization					(909)	(802)
Interest expense					(1,178)	(1,151)
Interest income					293	304
Other expense					(131)	(83)
Other income					108	94
Gain on sale of investments					7	-
Goodwill impairment					(17)	(18)
Asset impairment expense					(196)	(297)
Foreign currency transaction (losses) gains on net monetary position					(21)	(19)
Other non-operating expense					(82)	(7)
Income from continuing operations before taxes and equity in earnings of affiliates					$ 1,519	$ 1,445

Table of Contents

Assets by segment as of September 30, 2011 and December 31, 2010 were as follows:

	Total Assets September 30, 2011	December 31, 2010
	(in millions)	
Assets		
Latin America Generation	$ 10,545	$ 10,373
Latin America Utilities	8,938	9,872
North America Generation	4,403	4,681
North America Utilities	3,218	3,139
Europe Generation	4,264	4,178
Asia Generation	1,725	1,762
Discontinued businesses	407	468
Corp/Other & eliminations	7,383	6,038
Total Assets	$ 40,883	$ 40,511

13. OTHER INCOME (EXPENSE)

The components of other income for the three and nine months ended September 30, 2011 and 2010 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Tax credit settlement	$ 31	$ -	$ 31	$ -
Tax dispute settlement	14	-	14	-
Extinguishment of liability	-	-	-	62
Gain on sale of assets	9	5	25	7
Other	4	12	38	25
Total other income	$ 58	$ 17	$ 108	$ 94

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

Other income of $58 million for the three months ended September 30, 2011 was primarily due to an additional tax credit settlement from a favorable court decision in 2011 concerning reimbursement of excess non-income taxes paid from 1989 to 1992 at Eletropaulo and the reimbursement of income tax expense recognized during the quarter related to an indemnity agreement between Los Mina and the Dominican Republic government. Other income of $17 million for the three months ended September 30, 2010 was primarily related to the gain on sale of assets at Eletropaulo.

Other income of $108 million for the nine months ended September 30, 2011 was primarily related to the items described above, in addition to the gain on sale of mineral rights and land at IPL. Other income of $94 million for the nine months ended September 30, 2010 was primarily related to the extinguishment of a swap liability owed by two of our Brazilian subsidiaries, resulting in the recognition of a $62 million gain. The net impact to the Company after taxes and non-controlling interest was $9 million.

Table of Contents

The components of other expense for the three and nine months ended September 30, 2011 and 2010 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Loss on sale and disposal of assets	$ 31	$ 17	$ 60	$ 36
Loss on extinguishment of debt	36	-	52	9
Wind Generation transaction costs	-	-	-	22
Other	9	6	19	16
Total other expense	$ 76	$ 23	$ 131	$ 83

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

Other expense of $76 million for the three months ended September 30, 2011 was primarily due to the premium paid on the early retirement of debt at Gener and losses on the disposal of assets at TermoAndes and Eletropaulo. Other expense of $23 million for the three months ended September 30, 2010 was primarily comprised of losses on the disposal of assets at Eletropaulo and Gener.

Other expense of $131 million for the nine months ended September 30, 2011 was primarily due to the premium paid on early retirement of debt at Gener, a loss related to the early retirement of senior notes due in 2011 at IPL, and loss on disposal of assets at Eletropaulo and TermoAndes. Other expense of $83 million for the nine months ended September 30, 2010 included the previously capitalized transaction costs of $22 million that were incurred in connection with the preparation for the sale of a noncontrolling interest in our Wind Generation business. These costs were written off upon the expiration of the letter of intent (LOI) on June 30, 2010. Also, there was a $9 million loss on debt extinguishment at the Parent Company from the retirement of senior notes, and losses on disposal of assets at Eletropaulo and Gener.

14. IMPAIRMENTS

Asset Impairment

Asset impairment expense for the three and nine months ended September 30, 2011 and 2010 consisted of:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Wind turbines & deposits	$ 116	$ -	$ 116	$ -
Carbon reduction projects	33	-	33	-
Kelanitissa	4	-	37	-
Southland (Huntington Beach)	-	200	-	200
Tisza II	-	85	-	85
Other	10	11	10	12
Total asset impairment expense	$ 163	$ 296	$ 196	$ 297

During the third quarter of 2011, the Company evaluated the future use of certain wind turbines held in storage pending their installation. Due to reduced wind turbine market pricing and advances in turbine technology, the Company determined it was more likely than not that the turbines would be sold significantly

44

before the end of their previously estimated useful lives. In addition, the Company has concluded that more likely than not non-refundable deposits it had made in prior years to a turbine manufacturer for the purchase of wind turbines are not recoverable. The Company determined it was more likely than not that it would not proceed with the purchase of turbines due to the availability of more advanced and lower cost turbines in the market. These developments were more likely than not as of September 30, 2011 and as a result were considered impairment indicators. In October 2011, the Company determined that an impairment had occured as of September 30, 2011 as the aggregate carrying amount of $161 million of these assets was not recoverable and was reduced to their estimated fair value of $45 million determined under the market approach. This resulted in asset impairment expense of $116 million for the three and nine months ended September 30, 2011. Wind Generation is reported in the Corporate and Other segment

During the third quarter of 2011, the markets for emission reduction offsets, including Certified Emission Reductions (CERs) and European Allowance Units (EUAs), experienced a significant adverse change, as the global economic conditions contributed to unforeseen deterioration in the market prices of CERs and EUAs. This decline in the market prices of emission reduction offsets adversely impacted the Company s Carbon Reduction Projects in Asia and Latin America. The Latin American project also incurred current period operating losses and is projecting continuing operating and cash flow losses for future periods. Consequently, we determined that indicators of impairment existed as of September 30, 2011 and the carrying amounts of these projects were not recoverable based on undiscounted cash flows. The fair value of the projects was then determined using discounted cash flow analysis. The aggregate carrying amount of $49 million of these projects was written down as their estimated fair value was $11 million, resulting in asset impairment expense of $33 million, which was limited to the carrying amounts of long-lived assets. Carbon Reduction Projects are reported in the Corporate and Other segment.

During the second quarter of 2011, the Company recognized asset impairment expense of $33 million for the long-lived assets of Kelanitissa, our diesel-fired generation plant in Sri Lanka. We have continued to evaluate the recoverability of our long-lived assets at Kelanitissa as a result of both the existing government regulation which may require the government to acquire an ownership interest and the current expectation of future losses. Our evaluation during the quarter indicated that the long-lived assets were no longer recoverable and accordingly they were written down to their estimated fair value of $33 million based on a discounted cash flow analysis. The long-lived assets had a carrying amount of $66 million prior to the recognition of asset impairment expense. An additional impairment of $4 million was recognized in the three months ended September 30, 2011. Kelanitissa is a Build-operate-transfer (BOT) generation facility and payments under its PPA are scheduled to decline over the PPA term. It is possible that further impairment charges may be required in the future as Kelanitissa gets closer to the BOT date. Kelanitissa is reported in the Asia Generation reportable segment.

During the third quarter of 2011, the Company concluded it was more likely than not that it would sell its interest in two distribution companies and a small generation plant in Argentina. This was considered an impairment indicator. An evaluation of the recoverability of their carrying amount concluded that using probability-weighted undiscounted cash flows, the carrying amounts of the asset groups were recoverable and no impairment charge was recognized for the three months ended September 30, 2011. However, it is reasonably possible that the estimate of undiscounted cash flows at September 30, 2011 could change in the near term. For example, sales negotiations may be finalized in the near term resulting in the need to recognize an impairment charge, which may be material. The aggregate carrying amount of the entities at September 30, 2011 was approximately $317 million, which includes cumulative translation losses of $208 million currently classified as accumulated other comprehensive loss in equity. As the proceeds from a possible sale are likely to be minimal, we would be required to write down substantially all of the carrying amount of these entities.

During the third quarter of 2010, the Company entered into annual negotiations with the offtaker of its Tisza II generation plant in Hungary. As a result of these preliminary negotiations, as well as the further deterioration of the economic environment in Hungary, the Company determined that an indicator of impairment existed at September 30, 2010. Thus, the Company performed an asset impairment test in accordance with the accounting guidance on property, plant and equipment and determined that based on the undiscounted cash flow analysis, the carrying amount of the Tisza II asset group was not recoverable. The fair value of the asset group was then determined using a discounted cash flow analysis. The carrying value of the Tisza II asset group of $160 million exceeded the fair value of $75 million resulting in the recognition of asset impairment expense of $85 million during the three and nine months ended September 30, 2010. Tisza II is reported in the Europe Generation reportable segment.

In September 2010, the Office of Administrative Law in California approved the policy that will require the Company to change the process through which it uses ocean water to cool the generation turbines at its Alamitos, Huntington Beach and Redondo Beach (collectively Southland) gas-fired generation facilities in California. The policy requires compliance with the new regulations by December 31, 2020. The change in the water cooling process will result in significant future capital expenditures to ensure compliance with the new regulations or a shut down of the plants and the Company determined that an indicator of impairment existed at September 30, 2010. The Company performed an asset impairment test and the asset group was determined to be at the individual plant level and based on the undiscounted cash flow analysis, the Company determined that the Huntington Beach asset group was not recoverable. The fair value of the Huntington Beach asset group was then determined using a discounted cash flow analysis. The carrying value of the Huntington Beach plant of $288 million exceeded the fair value of $88 million resulting in the recognition of asset impairment expense of $200 million for the three and nine months ended September 30, 2010. The undiscounted cash flows of the Alamitos and Redondo Beach asset groups exceeded their respective carrying values and resulted in no impairment. Huntington Beach is reported in the North America Generation reportable segment.

Goodwill Impairment

Goodwill impairment was $17 million for the three and nine months ended September 30, 2011. During the third quarter of 2011, the Company identified higher coal prices and the resulting reduced operating margins in China as an impairment indicator for the goodwill at Chigen, our holding company that holds equity interests in Chinese ventures. A significant downward revision of cash flow forecasts indicated that the fair value of Chigen reporting unit was lower than its carrying amount. See Note 15 Other Non-operating Expense for further information. As of September 30, 2011, Chigen had goodwill of $17 million. The Company performed an interim impairment evaluation of Chigen s goodwill and determined that goodwill had no implied fair value. As a result, the entire carrying amount of $17 million was recognized as goodwill impairment.

Goodwill impairment was $18 million for the three and nine months ended September 30, 2010. During the third quarter of 2010, the Company determined that there was an indicator that the carrying value of goodwill related to Deepwater, our pet coke-fired merchant generation facility in Texas, was not recoverable. This determination was based primarily on the fact that Deepwater did not operate for more than 30 days in the three months ended September 30, 2010, had incurred operating and cash flow losses and was forecasting operating and cash flow losses for the remainder of 2010 through 2014 as a result of decreases in future power price expectations and an increase in pet coke prices affecting the market. Deepwater is reported in the North America Generation segment.

15. OTHER NON-OPERATING EXPENSE

Other non-operating expense of $82 million for the three and nine months ended September 30, 2011 primarily consisted of other-than-temporary impairments of equity method investments in China.

During the third quarter of 2011 as part of the quarterly close process, the Company evaluated YangCheng International Power Generating Co Ltd (YangCheng), a 2,100 MW coal-fired plant in China, for other-than-temporary-impairment. AES owns a 25% interest in YangCheng and the remaining equity interest in the venture is held by Chinese partners. During the nine months ended September 30, 2011, coal prices continued an upward trend in China, thereby, reducing the operating margin of coal generation facilities. During this time, there was no corresponding increase in tariffs to compensate for higher coal prices. Power prices in China are tightly regulated by the national and provincial governments, which often limit power generators ability to pass through increases in fuel costs to customers. In addition, under the YangCheng venture agreement, AES will surrender its equity interest to the venture partners in 2016 without additional compensation. During the nine months ended September 30, 2011, management continued to monitor the situation and in the third quarter determined that it was unlikely that there would be a reversal in the trends in coal prices during the remaining term of the venture. Accordingly, during September 2011, management revised downward its forecasts of earning and cash flows over the remaining term of the venture. The revised forecasts were significantly lower than management s earlier estimates such that the carrying amount of the investment in YangCheng was considered to have incurred an other-than-temporary-impairment. In determining the fair value of our investment, management used a discounted cash flow analysis based on probability-weighted revised cash distribution forecasts under multiple scenarios. As of September 30, 2011, YangCheng had a carrying amount of $100 million which was written down to the estimated fair value of $26 million, and the difference was recognized as other non-operating expense.

Other non-operating expense of $2 million and $7 million, respectively, for the three and nine months ended September 30, 2010 primarily consisted of an other-than-temporary impairment of an equity method investment.

16. DISCONTINUED OPERATIONS AND HELD FOR SALE BUSINESSES

Discontinued operations includes the results of the following generation businesses:

Eletropaulo Telecomunicacões Ltda. and AES Communications Rio de Janeiro S.A (collectively Brazil Telecom), our Brazil telecommunication businesses (held for sale in September 2011);

Eastern Energy, including Cayuga, Greenidge, Somerset and Westover, in New York (held for sale in March 2011);

Borsod and Tiszapalkonya, in Hungary (held for sale in March 2011);

Ras Laffan, in Qatar (sold in October 2010);

Barka, in Oman (sold in August 2010); and

Lal Pir and Pak Gen, in Pakistan (sold in June 2010).

For the nine months ended September 30, 2010, the Company recognized a gain on disposal and impairment losses totaling $57 million. The Company incurred a loss of $14 million, net of tax and noncontrolling interests on Lal Pir and Pak Gen as a result of an increase in net assets carrying value compared to the agreed upon sale proceeds. Additionally, the Company completed the sale of its interest in Barka in August 2010 and recognized a gain on disposal of $63 million, net of noncontrolling interests and $38 million of tax expense associated with the sale.

The following table summarizes the revenue, income from operations, income tax expense, impairment and gain on sale of discontinued operations for the three and nine months ended September 30, 2011 and 2010:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Revenue	$ 107	$ 218	$ 327	$ 948
(Loss) income from operations of discontinued businesses	$ (6)	$ 37	$ (10)	$ 115
Income tax benefit (expense)	31	(8)	33	(23)

Income from operations of discontinued businesses, net of tax	$	25	$	29	$	23	$	92
Gain on sale of discontinued operations	$	-	$	79	$	-	$	57

Table of Contents

17. ACQUISITIONS

In the second quarter of 2011, the Company finalized the purchase price allocation related to the acquisition of Ballylumford. There were no significant adjustments made to the preliminary purchase price allocation recorded in the third quarter of 2010 when the acquisition was completed.

On April 20, 2011, the Company announced the execution of a definitive agreement (the Merger Agreement) with DPL, the parent company of Dayton Power & Light Company, a utility company based in Ohio. Under the terms of the Merger Agreement, AES agreed to acquire DPL for an enterprise value of $4.7 billion, consisting of cash of $3.5 billion and the assumption of net debt of approximately $1.2 billion. Through its operating subsidiaries DP&L and DPL Energy Resources, DPL serves over 500,000 customers in West Central Ohio. Additionally, DPL operates over 3,800 MW of power generation facilities and provides competitive retail energy services to industrial and commercial customers. Upon closing of the transaction, DPL will become a wholly-owned subsidiary of AES.

The consummation of the transaction is subject to approval of the Public Utilities Commission of Ohio and FERC. By September 30, 2011, the transaction had been approved by DPL shareholders and had satisfied the antitrust review under the Hart-Scott-Rodino Act. Remaining approvals are expected to be obtained during the fourth quarter of 2011 or the first quarter of 2012, although there can be no assurance that such approvals will be obtained, or that they will be obtained on reasonable terms. The transaction is also subject to certain other closing conditions. After the announcement of the transaction, certain lawsuits were filed seeking to enjoin the merger and/or seek unspecified monetary damages, some of which name AES as a defendant. The Company believes it has meritorious defenses to the lawsuits and will assert them vigorously; however, there can be no assurances that it will be successful in its efforts.

18. EARNINGS PER SHARE

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

The following tables present a reconciliation of the numerator and denominator of the basic and diluted earnings per share computation for income from continuing operations for the three and nine months ended September 30, 2011 and 2010. In the table below, income represents the numerator and weighted-average shares represent the denominator:

	Three Months Ended September 30,					
	2011			2010		
	Loss	Shares	$ per Share	Income	Shares	$ per Share
	(in millions except per share data)					
BASIC EARNINGS PER SHARE						
Income from continuing operations attributable to The AES Corporation common stockholders	$ (119)	778	$ (0.15)	$ 41	794	$ 0.05
EFFECT OF DILUTIVE SECURITIES						
Stock options	-	-	-	-	2	-
Restricted stock units	-	-	-	-	3	-
DILUTED EARNINGS PER SHARE	$ (119)	778	$ (0.15)	$ 41	799	$ 0.05

48

Table of Contents

	Nine Months Ended September 30, 2011			2010		
	Income	Shares	$ per Share	Income	Shares	$ per Share
	(in millions except per share data)					
BASIC EARNINGS PER SHARE						
Income from continuing operations attributable to The AES Corporation common stockholders	$ 296	783	$ 0.38	$ 354	762	$ 0.46
EFFECT OF DILUTIVE SECURITIES						
Stock options	-	1	-	-	2	-
Restricted stock units	-	3	-	-	3	-
DILUTED EARNINGS PER SHARE	$ 296	787	$ 0.38	$ 354	767	$ 0.46

There were approximately 15,564,118 and 16,951,804 additional options outstanding at September 30, 2011 and 2010, respectively, that could potentially dilute basic earnings per share in the future. Those options were not included in the computation of diluted earnings per share because the exercise price exceeded the average market price during the related periods. For the three months ended September 30, 2011 and 2010, all convertible debentures were omitted from the earnings per share calculation because they were anti-dilutive. During the three months ended September 30, 2011, 115,597 shares of common stock were issued upon the exercise of stock options. For the nine months ended September 30, 2011 and 2010, all convertible debentures were omitted from the earnings per share calculation because they were anti-dilutive. During the nine months ended September 30, 2011, 1,073,539 shares of common stock were issued under the Company s profit sharing plan and 589,948 shares of common stock were issued upon the exercise of stock options.

19. REGULATORY ASSETS AND LIABILITIES

Regulatory liabilities generally represent obligations to make refunds to customers for previous collections of revenue and for costs that are not likely to be incurred or included in future rate events. For example, in July 2011, the Brazilian energy regulator (the Regulator) postponed the periodic review and reset of a component of Eletropaulo s regulated tariff, which determines the margin to be earned by Eletropaulo. The review and reset of this tariff component is performed every four years. From July 2011 through September 2011, Eletropaulo continued to invoice customers under the existing tariff rate, as required by the Regulator. Management believes that it is probable that the new tariff rate will be lower than the existing tariff rate, resulting in future refunds to customers, and has estimated the amount of this liability. Accordingly, as of September 30, 2011, Eletropaulo recognized a regulatory liability and corresponding reduction in revenue of approximately $104 million. It is at least reasonably possible that future events confirming the final amount of the regulatory liability or a change in the estimated amount of the liability will occur in the near term as the periodic review and tariff reset process progresses with the Regulator through the remainder of 2011 and into 2012. The primary factors in the ongoing discussions between the Brazilian distribution companies, including Eletropaulo, and the Regulator that cause the estimate to be sensitive to change include the regulatory asset base and the investment return rate assumptions used in the determination of the margin. The final amount of the regulatory liability may differ from the estimated amount recognized as of September 30, 2011.

20. SUBSEQUENT EVENTS

On October 3, 2011, the Company completed the placement of $1.25 billion aggregate principal amount senior notes with Wells Fargo Bank N.A. See Note 8 *Debt, Non-Recourse* Debt for further information.

In July 2011, a subsidiary of the Company entered into an agreement to sell its ownership interest in two telecommunication companies in Brazil. The Company held approximately 46% ownership interest in these companies through the subsidiary. The transaction closed on October 31, 2011 and the subsidiary received approximately R$1,522 million ($901million), subject to customary purchase price adjustments. The estimated gain on the sale before noncontrolling interests and taxes is approximately R$1,333 million ($789 million), subject to final purchase price adjustments.

On October 20, 2011, a subsidiary of the Company signed a share sale agreement with Electrabel International Holdings B.V. (EIH), a subsidiary of GDF SUEZ S.A. (GDFS) for the sale of 80% of its interest in the wholly-owned holding company that holds the Company s interest in AES Energia Cartagena S.R.L. (AES Cartagena), a 1,199 MW gas-fired generation business in Spain, for 172 million ($234 million), subject to customary purchase price adjustments. AES owns approximately 70.81% of AES Cartagena through this holding company structure. Under the terms of the sale agreement, EIH has an option to purchase AES remaining 20% interest in the holding company for a fixed price of 28 million ($38 million) during a five month period beginning 13 months from the date the sale closes. Subject to regulatory and lenders approvals, the sale is expected to close by the end of 2011. Concurrent with the sale, GDFS agreed to settle the outstanding arbitration between the parties regarding certain emissions costs and other taxes that AES Cartagena sought to recover from GDFS as energy manager under the existing commercial arrangements and to pay 58 million ($79 million) to AES Cartagena for such costs incurred by AES Cartagena during the period up to December 31, 2010 and additional amounts for such costs incurred by AES Cartagena during the period from January 1, 2011 until closing of the sale. However, the settlement of the arbitration is contingent on consummation of the sale. See Note 9 *Contingencies and Commitments* for further information.

Subsequent to September 30, 2011, the Company continued to repurchase stock under the stock repurchase program announced on July 7, 2010. The Company has repurchased 5,554,185 shares at a cost of $54 million subsequent to September 30, 2011, bringing the cumulative total through November 3, 2011 to 33,924,805 shares at a total cost of $378 million (average price of $11.16 per share including commissions). For additional information, see Note 11 *Equity*.

Table of Contents

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

In this Quarterly Report on Form 10-Q (Form 10-Q), the terms AES, the Company, us, or we refer to the consolidated entity and all of its subsidiaries and affiliates, collectively. The term The AES Corporation or the Parent Company refers only to the parent, publicly-held holding company, The AES Corporation, excluding its subsidiaries and affiliates.

On June 1, 2011, The AES Corporation filed a Current Report on Form 8-K (June 2011 Form 8-K) to recast previously filed financial statements included in the Company s Form 10-K for the year ended December 31, 2010 (2010 Form 10-K) to reclassify certain businesses held for sale as discussed in Note 16 *Discontinued Operations and Held for Sale Businesses* to item 1. Financial Statements. The condensed consolidated financial statements included in Item 1. Financial Statements of this Form 10-Q and the discussions contained herein should be read in conjunction with our 2010 Form 10-K and the June 2011 Form 8-K.

FORWARD-LOOKING INFORMATION

The following discussion may contain forward-looking statements regarding us, our business, prospects and our results of operations that are subject to certain risks and uncertainties posed by many factors and events that could cause our actual business, prospects and results of operations to differ materially from those that may be anticipated by such forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those described in Item 1A. Risk Factors of our 2010 Form 10-K filed on February 25, 2011, the Form 10-Q for the first quarter of 2011 filed on May 6, 2011 and this Form 10-Q for the period ended September 30, 2011. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this report. We undertake no obligation to revise any forward-looking statements in order to reflect events or circumstances that may subsequently arise. If we do update one or more forward-looking statements, no inference should be drawn that we will make additional updates with respect to those or other forward-looking statements. Readers are urged to carefully review and consider the various disclosures made by us in this report and in our other reports filed with the SEC that advise of the risks and factors that may affect our business.

Overview of Our Business

We are a global power company. We operate two primary lines of business. The first is our Generation business, where we own and/or operate power plants to generate and sell power to wholesale customers such as utilities, other intermediaries and certain end-users. The second is our Utilities business, where we own and/or operate utilities which distribute, transmit and sell electricity to end-user customers in the residential, commercial, industrial and governmental sectors within a defined service area and in certain circumstances, sell electricity on the wholesale market. For the nine months ended September 30, 2011 our Generation and Utilities businesses comprised approximately 45% and 55% of our consolidated revenue, respectively. For additional information regarding our business, see Item 1. Business of the June 2011 Form 8-K.

We are also continuing to expand our wind and solar businesses. These initiatives are not material contributors to our operating results, but we believe that certain of these initiatives may become material in the future. For additional information regarding our business, see Item 1. Business of the June 2011 Form 8-K.

Our Organization and Segments. The Company s current management reporting structure is organized along our two lines of business (Generation and Utilities) and three regions: (1) Latin America & Africa; (2) North America; and (3) Europe, Middle East & Asia (collectively EMEA), each managed by a regional president. The financial reporting segment structure uses the Company s management reporting structure as its foundation and reflects how the Company manages the business internally. On September 6, 2011, the Company announced the appointment of Andrés Gluski as its President and Chief Executive Officer. Subsequently, on October 18, 2011, the Company announced a plan to redefine its operational management and organizational structure. The planned reporting structure will remain organized along two lines of business Generation and Utilities, however, we are continuing to evaluate both the timing and impact, if any, that the realignment will have on our reportable segments. For the three and nine months ended September 30, 2011, the Company applied the segment reporting accounting guidance, which provides certain quantitative thresholds and aggregation criteria, and concluded that it has the following six reportable segments:

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

Corporate and Other. The Company s Europe Utilities, Africa Utilities, Africa Generation, Wind Generation operating segments and climate solutions and other renewables projects are reported within Corporate and Other because they do not meet the criteria to allow for aggregation with another operating segment or the quantitative thresholds that would require separate disclosure under segment reporting accounting guidance. None of these operating segments are currently material to our financial statement presentation of reportable segments, individually or in the aggregate. Corporate and Other also includes costs related to corporate overhead which are not directly associated with the operations of our six reportable segments and other intercompany charges such as self-insurance premiums which are fully eliminated in consolidation.

Components of Revenue and Cost of Sales. Revenue includes revenue earned from the sale of energy from our utilities and the production of energy from our generation plants, which are classified as regulated and unregulated on the condensed consolidated statements of operations, respectively. Revenue also includes the gains or losses on derivatives (including embedded derivatives other than foreign currency embedded derivatives) associated with the sale of electricity. Cost of sales includes costs incurred directly by the businesses in the ordinary course of business. Examples include electricity and fuel purchases, maintenance, operations, non-income taxes and bad debt expense and recoveries as well as depreciation and general and administrative and support costs, including employee-related costs, that are directly associated with the operations of a particular business. Cost of sales also includes the gains or losses on derivatives (including embedded derivatives other than foreign currency embedded derivatives) associated with the purchase of electricity or fuel.

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

One of the key factors which affect our Generation business is our ability to enter into contracts for the sale of electricity and the purchase of fuel used to produce that electricity. Long-term contracts are intended to reduce the exposure to volatility associated with fuel prices in the market and the price of electricity by fixing the revenue and costs for these businesses. The majority of the electricity produced by our Generation businesses is sold under long-term contracts, or PPAs, to wholesale customers. In turn, most of these businesses enter into long-term fuel supply contracts or fuel tolling arrangements where the customer assumes full responsibility for purchasing and supplying the fuel to the power plant. While these long-term contractual agreements reduce exposure to volatility in the market price for electricity and fuel, the predictability of operating results and cash flows vary by business based on the extent to which a facility s generation capacity and fuel requirements are contracted and the negotiated terms of these agreements. Entering into these contracts exposes us to counterparty credit risk. For further discussion of these risks, see *Supplier and/or customer concentration may expose the Company to significant financial credit or performance risks.* in Item 1A. Risk Factors of the 2010 Form 10-K.

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

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

We also attempt to limit risk by hedging much of our interest rate and commodity risk, and by matching the currency of most of our subsidiary debt to the revenue of the underlying business. However, we only hedge a portion of our currency and commodity risks, and our businesses are still subject to these risks, as further described in Item 1A. Risk Factors of the 2010 Form 10-K, *We may not be adequately hedged against our exposure to changes in commodity prices or interest rates*. Commodity and power price volatility could continue to impact our financial metrics to the extent this volatility is not hedged. For a discussion of our sensitivities to commodity, currency and interest rate risk, see Item 3. Quantitative and Qualitative Disclosures About Market Risk in this Form 10-Q.

Due to our global presence, the Company has significant exposure to foreign currency fluctuations. The exposure is primarily associated with the impact of the translation of our foreign subsidiaries operating results from their local currency to U.S. dollars that is required for the preparation of our consolidated financial statements. Additionally, there is a risk of transaction exposure when an entity enters into transactions, including debt agreements, in currencies other than their functional currency. These risks are further described in Item 1A. Risk Factors of the 2010 Form 10-K, *Our financial position and results of operations may fluctuate significantly due to fluctuations in currency exchange rates experienced at our foreign operations*. In the three and nine months ended September 30, 2011, changes in foreign currency exchange rates have had a significant impact on our operating results. If the current foreign currency exchange rate volatility continues, our gross margin and other financial metrics could be affected.

Another key driver of our results is our ability to bring new businesses into commercial operations successfully. We currently have approximately 2,294 MW of projects under construction in eleven countries. Our prospects for increases in operating results and cash flows are dependent upon successful completion of these projects on time and within budget. However, as disclosed in Item 1A. Risk Factors of the 2010 Form 10-K, *Our business is subject to substantial development uncertainties*, construction is subject to a number of risks, including risks associated with site identification, financing and permitting and our ability to meet construction deadlines. Delays or the inability to complete projects and commence commercial operations can result in increased costs, impairment of assets and other challenges involving partners and counterparties to our construction agreements, PPAs and other agreements.

Our gross margin is also impacted by the fact that in each country in which we conduct business, we are subject to extensive and complex governmental regulations such as regulations governing the generation and distribution of electricity, and environmental regulations which affect most aspects of our business. Regulations differ on a country by country basis (and even at the state and local municipality levels) and are based upon the type of business we operate in a particular country, and affect many aspects of our operations and development projects. Our ability to negotiate tariffs, enter into long-term contracts, pass through costs related to capital expenditures and otherwise navigate these regulations can have an impact on our revenue, costs and gross margin. Environmental and land use regulations, including existing and proposed regulation of GHG emissions, could substantially increase our capital expenditures or other compliance costs, which could in turn have a material adverse affect on our business and results of operations. For a further discussion of the Regulatory Environment, see Note 9 *Contingencies and Commitments Environmental,* included in Item 1. Financial Statements of this Form 10-Q and Item 1. Business *Regulatory Matters Environmental and Land Use Regulations* and Item 1A. Risk Factors Risks Associated with Government Regulation and Laws of the 2010 Form 10-K.

Key Drivers of Results in the Three Months Ended September 30, 2011

During the three months ended September 30, 2011, the Company s gross margin increased $53 million and net income attributable to The AES Corporation decreased $245 million, while net cash from operating activities increased $127 million compared to the same period in 2010.

During the three months ended September 30, 2011, the Company benefited from new businesses including Ballylumford, in Northern Ireland, acquired in August 2010, and Angamos I, in Chile, and Maritza, in Bulgaria, which commenced commercial operations in April and June 2011, respectively. Gener, our generation business in Chile, saw improvements over the prior year due to higher generation at the Electrica Santiago plant running on liquefied natural gas and higher contract and spot sales. These favorable results were offset by the unfavorable impacts of outages in Panama and an unfavorable adjustment to regulatory liabilities at Eletropaulo related to the estimated impact of the July 2011 tariff reset as discussed below. Absent the favorable impact of foreign currency, gross margin for the Company would have remained flat for the quarter. During the three months ended September 30, 2011, gross margin did not increase at the same rate as revenue primarily due to the pass-through of fuel costs and purchased energy that increase revenue but do not have a corresponding impact on gross margin as well as a forced outage in Panama.

For the remainder of 2011 and into 2012, we expect to face continued challenges at certain of our businesses. The determination of the 2011 tariff reset in Brazil has been postponed until late 2011. Although we expect the tariff to decrease, its components and their potential impact on our Brazilian utility, Eletropaulo,

Table of Contents

remain uncertain at this time. Additionally, the Company identified damage to a tunnel at a hydroelectric plant in Panama in late 2010, which will cause the plant to be offline through mid-2012. Until the ultimate disposition of Eastern Energy in New York, which is classified as held for sale, the Company will continue to see the effects of relatively lower gas prices and a decline in power prices relative to coal. These conditions are not hedged for the remainder of 2011. In addition, as further described in *Key Trends and Uncertainties Sale of Eastern Energy* below, we placed Eastern Energy into discontinued operations based on our intention to sell our interest in the business. While we are continuing our efforts to sell our interest in the business and believe that the sale is probable of being consummated by March 31, 2012 for the assets to continue to be presented as discontinued operations, there can be no assurance that we will be successful in these efforts. In addition, we currently anticipate a benefit to our 2011 results if we close the sale of 80% of our interest in AES Cartagena. However, there can be no assurance that we will close the transaction or if we do, that it will close by year-end. Additional items that could impact our 2011 or 2012 results are discussed in *Key Trends and Uncertainties* below, along with the risk factors included in our 2010 Form 10-K and Forms 10-Q for the periods ended March 31, 2011 and September 30, 2011. However, management expects that improved operating performance at certain businesses and growth from newly acquired businesses and businesses expected to commence operations in 2011 may lessen or offset the impact of the challenges described above. If these favorable effects do not occur, or if the challenges described above and elsewhere in this section impact us more significantly than we currently anticipate, or if volatile foreign currencies and commodities move unfavorably, then these adverse factors (or other adverse factors unknown to us) may impact our gross margin, net income attributable to The AES Corporation and cash flows.

The following briefly describes the key changes in our reported revenue, gross margin, net income attributable to The AES Corporation, diluted earnings per share from continuing operations, Adjusted Earnings per Share (a non-GAAP measure) and net cash provided by operating activities for the three and nine months ended September 30, 2011 compared to the three and nine months ended September 30, 2010 and should be read in conjunction with our *Consolidated Results of Operations* discussion below.

Performance Highlights

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	**2010**	**% Change**	**2011**	**2010**	**% Change**
	($ s in millions, except per share amounts)					
Revenue	$ 4,381	$ 3,990	10%	$ 13,117	$ 11,777	11%
Gross Margin	$ 1,020	$ 967	5%	$ 3,019	$ 2,901	4%
Net (Loss) Income Attributable to The AES Corporation	$ (131)	$ 114	-215%	$ 267	$ 445	-40%
Net Cash Provided by Operating Activities	$ 1,127	$ 1,000	13%	$ 2,308	$ 2,416	-4%
Diluted (Loss) Earnings per Share from Continuing Operations	$ (0.15)	$ 0.05	-400%	$ 0.38	$ 0.46	-17%
Adjusted Earnings Per Share (a non-GAAP measure)[1]	$ 0.27	$ 0.20	35%	$ 0.76	$ 0.70	9%

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

Our third quarter and year-to-date financial results include the following highlights:

Three months ended September 30, 2011:

Revenue increased $391 million, or 10%, to $4.4 billion in the three months ended September 30, 2011 compared with $4.0 billion in the three months ended September 30, 2010. Key drivers of the increase included:

- the favorable impact of foreign currency of $173 million;
- the impact of new businesses including Ballylumford, in Northern Ireland, acquired in August 2010 and Angamos I, in Chile, and Maritza, in Bulgaria, that commenced commercial operation in April and June 2011, respectively;

55

- increased prices at our generation businesses in Argentina and at Gener, in Chile; and
- increased volume at our Brazilian utilities, driven by increased market demand.

These increases were partially offset by:

- lower prices at Eletropaulo, our utility in Brazil, primarily related to the estimated impact of the July 2011 tariff reset which has been postponed by the Brazilian energy regulatory agency; and
- the unfavorable impact of an unrealized mark-to-market derivative loss at Sonel.

Gross margin increased $53 million, or 5%, to $1.0 billion in the three months ended September 30, 2011 compared with $967 million in the three months ended September 30, 2010. Key drivers of the increase included:

- the favorable impact of foreign currency of $51 million;
- the impact of new businesses including Ballylumford, acquired in August 2010 and Angamos and Maritza that commenced commercial operation in April and June 2011, respectively;
- increased volume at Gener; and
- decreased fixed costs primarily due to a non-recurring reduction in bad debt expense and lower contingencies at Eletropaulo.

These increases were partially offset by:

- the unfavorable impact of an unrealized mark-to-market derivative loss at Sonel;
- lower prices at our Brazilian utilities, primarily due to the estimated impact of the July 2011 tariff reset as discussed above;
- the unfavorable impact of outages in Panama; and
- higher fuel prices at Gener in Chile.

Net income attributable to The AES Corporation decreased $245 million to a loss of $131 million in the three months ended September 30, 2011 compared with income of $114 million in the three months ended September 30, 2010. Key drivers of the decrease included:

- foreign currency losses at The AES Corporation due to the decrease in valuation of cash, note receivables and trade receivables related to the weakening of the Euro and British Pound and losses in Chile associated with the net working capital denominated in Chilean Pesos due to the devaluation of the Chilean Peso;

- other-than-temporary impairment losses related to two of our equity investments in China; and

- the gain on sale of discontinued operations related to the sale of Barka which occurred in August 2010.

These decreases were partially offset by:

- a decrease in asset impairment losses due to higher impairment losses in the prior year related to Southland and Tisza II generation facilities offset primarily by the current year asset impairment for Wind.

Table of Contents

Net cash provided by operating activities increased $127 million, or 13%, to $1.1 billion in the three months ended September 30, 2011 compared with $1.0 billion in the three months ended September 30, 2010. Key drivers of the increase included:

- an increase at our Latin American generation businesses primarily due to higher collection of account receivables in Chile;
- an increase at our Europe generation businesses as a result of commenced commercial operations at Maritza in Bulgaria and a full quarter of operations at Ballylumford in Northern Ireland; offset by
- a decrease at our Latin American utilities businesses primarily due to higher energy purchases and regulatory charges at Eletropaulo and higher working capital needs in El Salvador;
- a decrease at our Asia generation businesses primarily due to lower operating income at Masinloc in the Philippines as well as from the sale of Ras Laffan in 2010.

Nine months ended September 30, 2011:

Revenue increased $1.3 billion, or 11%, to $13.1 billion in the nine months ended September 30, 2011 compared with $11.8 billion in the nine months ended September 30, 2010. Key drivers of the increase included:

- the favorable impact of foreign currency of $600 million;
- the impact of new businesses including Ballylumford, acquired in August 2010 and Angamos and Maritza, which commenced commercial operations in April and June 2011, respectively;
- increased price and volume in Chile;
- increased price at our generation businesses in Argentina; and
- increased volume at our Brazilian utilities, driven by increased market demand.

These increases were partially offset by:

- lower prices at our utility businesses in Brazil primarily due to the estimated impact of the July 2011 tariff reset which has been postponed by the Brazilian energy regulatory agency;
- lower volume at Cartagena and Tisza II; and
- the unfavorable impact of an unrealized mark-to-market derivative loss at Sonel.

Gross margin increased $118 million, or 4%, to $3.0 billion in the nine months ended September 30, 2011 compared with $2.9 billion in the nine months ended September 30, 2010. Key drivers of the increase included:

- the favorable impact of foreign currency of $148 million;
- the impact of new businesses including Ballylumford, acquired in August 2010, and Angamos and Maritza, which commenced commercial operation in April and June 2011, respectively;
- increased price and volume at Gener; and
- increased volume at our Brazilian utilities, driven by increased market demand.

Table of Contents

These increases were partially offset by:

- lower prices at our Brazilian utility business, primarily related to the estimated impact of the July 2011 tariff reset which has been postponed by the Brazilian energy regulatory agency;
- the unfavorable impact of outages in Panama;
- the unfavorable impact of an unrealized mark-to-market derivative loss at Sonel;
- lower volume at IPL in Indiana;
- an increase in global fixed costs, particularly at our Latin American generation businesses;
- lower spot prices and volume at Masinloc; and
- lower prices at Kilroot.

Net income attributable to The AES Corporation decreased $178 million, or 40%, to $267 million in the nine months ended September 30, 2011 compared with $445 million in the nine months ended September 30, 2010. Key drivers of the decrease included:

- a decrease in net equity in earnings of affiliates partially offset by income tax expense related to the sale of the Company s indirect investment in CEMIG in 2010;
- a decrease in discontinued operations related to the sale of Barka which occurred in August 2010 and lower net income related to discontinued businesses in 2011; and
- other-than-temporary impairment losses related to our equity investments in China.

These decreases were partially offset by:

- a decrease in asset impairment losses as described above;
- a decrease in income tax expense primarily due to the extension of a favorable U.S. tax law in the fourth quarter of 2010 impacting distributions from certain non-U.S. subsidiaries; and
- an increase in gross margin as described above.

Net cash provided by operating activities decreased $108 million, or 4%, to $2.3 billion in the nine months ended September 30, 2011 compared with $2.4 billion in the nine months ended September 30, 2010. Please refer to *Consolidated Cash Flows Operating Activities* for further discussion.

Non-GAAP Measure

We define adjusted earnings per share (Adjusted EPS) as diluted earnings per share from continuing operations excluding gains or losses of the consolidated entity due to (a) mark-to-market amounts related to derivative transactions, (b) unrealized foreign currency gains or losses, (c) significant gains or losses due to dispositions and acquisitions of business interests, (d) significant losses due to impairments, and (e) costs due to the early retirement of debt. The GAAP measure most comparable to Adjusted EPS is diluted earnings per share from continuing operations. AES believes that Adjusted EPS better reflects the underlying business performance of the Company and is considered in the Company s internal evaluation of financial performance. Factors in this determination include the variability due to mark-to-market gains or losses related to derivative transactions, currency gains or losses, losses due to impairments and strategic decisions to dispose or acquire business interests or retire debt, which affect results in a given period or periods. Adjusted EPS should not be construed as an alternative to diluted earnings per share from continuing operations, which is determined in accordance with GAAP.

Table of Contents

For the three months ended September 30, 2011, the Company reported a loss from continuing operations of $0.15 per share. For purposes of measuring diluted loss per share under GAAP, common stock equivalents were excluded from weighted average shares as their inclusion would be antidilutive. However, for purposes of computing Adjusted EPS (a non-GAAP measure), the Company has included the impact of dilutive common stock equivalents as the inclusion of the defined adjustments result in income for Adjusted EPS. The table below reconciles the weighted average shares used in GAAP diluted earnings per share to the weighted average shares used in calculating the non-GAAP measure of Adjusted EPS:

	Three Months Ended September 30, 2011		
	Loss	**Shares**	**$ per Share**
Reconciliation of Denominator Used For Adjusted Earnings Per Share			
GAAP DILUTED EARNINGS PER SHARE			
Loss from continuing operations attributable to The AES Corporation common stockholders	$ (119)	778	$ (0.15)
EFFECT OF DILUTIVE SECURITIES			
Stock options	-	1	-
Restricted stock units	-	3	-
NON-GAAP DILUTED EARNINGS (LOSS) PER SHARE	$ (119)	782	$ (0.15)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Reconciliation of Adjusted Earnings Per Share				
Diluted earnings per share from continuing operations	$ (0.15)	$ 0.05	$ 0.38	$ 0.46
Derivative mark-to-market (gains)/losses(1)	0.02	0.02	0.01	0.01
Currency transaction (gains)/losses(2)	0.10	(0.13)	0.02	(0.04)
Disposition/acquisition (gains)/losses	-	-	-	-(3)
Impairment losses	0.27(4)	0.26(5)	0.31(6)	0.26(5)
Debt retirement (gains)/losses	0.03(7)	-	0.04(8)	0.01(9)
Adjusted earnings per share	$ 0.27	$ 0.20	$ 0.76	$ 0.70

(1) Derivative mark-to-market (gains)/losses were net of income tax per share of $0.01 in the three months ended September 30, 2011 and 2010, and of $0.00 in the nine months ended September 30, 2011 and 2010.

(2) Unrealized foreign currency transaction (gains)/losses were net of income tax per share of $0.01 and $0.00 in the three months ended September 30, 2011 and 2010, respectively, and of $0.00 and $(0.01) in the nine months ended September 30, 2011 and 2010, respectively.

(3) The Company did not adjust for the gain or the related tax effect from the sale of its indirect investment in CEMIG in its determination of Adjusted EPS because the gain was recognized by an equity method investee. The Company does not adjust for transactions of its equity method investees in its determination of Adjusted EPS.

(4) Amount includes equity method investment impairment at Chigen, including YangCheng, of $79 million or $0.10 per share, asset impairments at Wind of $116 million ($76 million, and $0.10 per share, net of income tax), Carbon Reduction Projects of $33 million or $0.04 per share, and Bohemia of $9 million ($6 million, and $0.01 per share, net of income tax), and goodwill impairment at Chigen of $17 million or $0.02 per share.

(5) Amount includes asset impairments at Southland (Huntington Beach) of $200 million and Tisza of $85 million ($130 million, or $0.17 per share, and $55 million, or $0.07 per share, net of income tax, respectively) and goodwill impairment at Deepwater of $18 million ($12 million, or $0.02 per share, net of income tax).

(6) Amount includes asset impairments described in footnote (4) above, in addition to $37 million at Kelanitissa ($34 million, or $0.04 per share, net of noncontrolling interests).

(7) Amount includes loss on retirement of debt at Gener of $38 million ($22 million, or $0.03 per share, net of noncontrolling interests and income tax).

Table of Contents

(8) Amount includes loss on retirement of debt described in footnote (7) above, in addition to IPL of $15 million ($10 million, or $0.01 per share, net of income tax).

(9) Amount includes loss on retirement of Parent Company debt of $9 million ($6 million, or $0.01 per share, net of income tax).

Management s Priorities

Management has re-evaluated its priorities following the recent appointment of its new CEO. Management is focused on the following priorities:

To resolve the remaining conditions precedent to allow us to close the acquisition of DPL, Inc. For a discussion of risks related to the DPL transaction, see Item 1A. *Risk Factors* in our Form 10-Q for the quarter ended March 31, 2011;

Execution of our geographic concentration strategy to maximize shareholder value through a disciplined capital allocation inclusive of: strategic portfolio management, corporate debt reduction, and return of capital to shareholders;

Completing the restructuring/sale of certain businesses such as Eastern Energy and closing the sales of businesses for which we have signed agreements with counterparties such as AES Cartagena;

Implementing a management realignment of our businesses under two business lines: Utilities and Generation and achieving cost savings through the alignment of overhead costs with business requirements, systems automation and optimal allocation of business development spending;

Continued improvement of operations in the existing portfolio;

Repairing the Esti hydro tunnel in Panama, as further described in *Key Trends and Uncertainties Operations* below;

Achieving full commercial operation at Maritza in Bulgaria. The plant has started partial operations with commercial production now at 620 MW and has passed capacity tests at 670 MW. Final regulatory approval for full production at 670 MW is pending as further described in *Key Trends and Uncertainties Development* below; and

Completion of an approximately 2,294 MW (including the remaining capacity at Maritza) construction program; and the integration of new projects into existing businesses. During the three months ended September 30, 2011, the following projects commenced commercial operations:

Project	**Location**	**Fuel**	**Gross MW**	**AES Equity Interest (Percent, Rounded)**
Trinidad I[1]	Trinidad	Gas	394	10%
Changuinola I	Panama	Hydro	111	100%
Laurel Mountain	US-WV	Wind	98	100%
AES Solar	Italy	Solar	18	50%
Sao Joaquim	Brazil	Hydro	3	24%

(1) Trinidad is an equity method investment held by AES.

Key Trends and Uncertainties

Our operations continue to face many risks as discussed in Item 1A. Risk Factors of the 2010 Form 10-K. Some of these challenges are also described above in *Key Drivers of Results in the Three Months Ended September 30, 2011*. We continue to monitor our operations and address challenges as they arise.

Table of Contents

Development

During the quarter, the Company successfully completed construction and commenced commercial operations at projects totaling approximately 624 MW. In addition, engineering efforts were completed to increase capacity at Maritza, a 670 MW coal-fired project in Bulgaria. After certain delays, Maritza began commercial operations on June 3, 2011 at a reduced capacity level of 494 MW. During the quarter, engineering efforts increased capacity to its full design of 670 MW. As noted above, Maritza is currently operating at 620 MW and efforts continue to obtain regulatory approval to operate at the full design capacity of 670 MW. As a result of delays in reaching commercial operations, the project debt is in default and the Company is working with its lenders to resolve the default. In addition, the Company is in litigation with the contractor regarding the cause of delays. The EPC contract was terminated for cause by the Company during the first quarter of 2011. At this time, we believe that Maritza will receive regulatory approval to operate at full capacity by the end of 2011. However, due to the inherent uncertainties, there could be further delays in obtaining regulatory approval to operate at the full design capacity. There can be no assurance that Maritza will resolve the default with the lenders or prevail in the litigation referenced above, which could result in loss in the value of some or all of our investment or require additional funding for the project. Any of these events could have a material adverse effect on the Company s operating results or financial position.

In addition, the Company has a number of additional projects under construction which are expected to commence commercial operations in 2011, including Changuinola II in Panama, and a number of wind and solar projects. While we expect these projects will be completed on time, there can be no assurance that these projects will commence commercial operations on time and on budget, due to the inherent uncertainties associated with the development process. For further discussion of the risks associated with development, see Item 1A. Risk Factors *Our business is subject to substantial development uncertainties* of the 2010 Form 10-K.

Operations

Beginning in August 2010 the Esti power plant, a 120 MW run-of-river hydroelectric power plant in Panama, experienced a reduction in power generation. Following an inspection of its tunnel infrastructure in October 2010, which indicated damage, the plant was taken offline. A significant repair of the Esti tunnel and additional surrounding support structures was deemed necessary to allow the plant to continue operation and to prevent future potential damage to the tunnel. AES Panama is partially covered for business interruption losses and property damage under existing insurance programs. In June 2011, AES Panama entered into a contract for the repair of the Esti tunnel and the surrounding support structures and on July 15, 2011 the Notice to Proceed was executed. Under the contract, the repairs will be performed over an 11-month period. The Esti power plant is projected to resume operations by the second quarter of 2012. However, due to the inherent uncertainties associated with construction, it is possible that commercial operations may resume after this timeframe.

Our utility businesses are subject to significant government laws and regulations. Changes in these regulations are often uncertain and difficult to predict. In particular, our inability to predict, influence or respond appropriately to changes in law or regulatory schemes, including the inability to obtain expected or contracted increases in electricity tariff rates or tariff adjustments for increased expenses, could have an unfavorable impact on the results of operations of these businesses. For example, since 2005, one of our distribution companies in Argentina has only received partial increases in its tariff associated with operational costs and cost of capital. Operating deficits and unfunded capital investments have been subsidized by the Company. A decision to sell or dispose of the distribution company (which we believe is more likely than not) or further delays in receiving the remaining portion of the tariff could adversely affect the carrying amount of the distribution company, which could be material. The carrying amount of the distribution company at September 30, 2011 was approximately $189 million, which includes cumulative translation losses of $140 million currently classified as accumulated other comprehensive loss in equity. As the proceeds from a possible sale are likely to be minimal, we would be required to write down substantially all of the carrying amount of the distribution company.

Table of Contents

Other regulatory changes that have a potential to adversely impact the results of our utility businesses include regulatory tariff revisions. For example, Eletropaulo, our utility business in Brazil, is currently billing its customers under the current tariff as required by the regulator. In July 2011, the regulator postponed the review and reset of Eletropaulo s regulated tariff, which includes a tariff component that determines the margin Eletropaulo is allowed to earn. The review and reset of the regulated tariff is performed every four years. Management believes that it is probable that the new tariff rate will be lower than the current tariff rate, resulting in future refunds to customers, and based on its best estimate continues to record the amount of future refunds as a reduction of revenue and a regulatory liability. The estimate is sensitive to the key assumptions that determine Eletropaulo s margin such as the regulatory asset base and the investment return rate. These assumptions are subject to ongoing discussions with the regulator. As the periodic review and reset process progresses with the regulator through the remainder of 2011 and into 2012, it is at least reasonably possible that the estimated amount of refunds will change in amounts that could require more refunds than we currently expect, in amounts that could be material.

Indiana Tree Trimming Regulation

In February 2009, an IPL customer filed a formal complaint claiming IPL s tree trimming practices were unreasonable and expressed concerns with language contained in IPL s tariff that addressed IPL s tree trimming and tree removal rights. Subsequently, the Indiana Utility Regulatory Commission (IURC) initiated a generic investigation into electric utility tree trimming practices and tariffs in Indiana. In November 2010, the IURC issued an order in the investigation, which imposed additional requirements on the conduct of tree trimming. The order included requirements on utilities to provide advance customer notice and obtain customer consent or additional easements if existing easements and rights of way are insufficient to permit pruning in accordance with the required industry standards or in the event that a tree would need to have more than 25% of its canopy removed. The order also directed that a rulemaking would be initiated to further address vegetation management practices. In December 2010, notices of appeal and petitions for reconsideration, clarification and/or rehearing were filed by multiple parties, including IPL.

On July 7, 2011, the IURC issued an additional tree trimming order which did not provide the relief IPL was seeking, but clarified utility customer notice requirements and the relationship of the order to property rights and tariff requirements. It also clarified that in cases of emergency or public safety, utilities may, without customer consent, remove more than 25% of a tree or trim beyond existing easement or right of way boundaries to remedy the situation. The IURC is currently in the process of promulgating formal rules to implement the order. IPL and other interested parties will participate in this rulemaking process. It is not possible to predict the outcome of this matter, but these proceedings could significantly increase IPL s vegetation management costs and the costs of defending IPL s vegetation management program in litigation, which could have a material impact on our consolidated financial statements.

Sale of Eastern Energy

As disclosed in the Company s Form 10-K for the year ended December 31, 2010 filed on February 28, 2011 and our Form 8-K dated June 1, 2011, the Company s North American businesses continue to face pressure as a result of high coal prices relative to natural gas, which has affected the results of certain of our coal plants in the region, particularly those which are merchant plants that are exposed to market risk, such as Eastern Energy. The Company has also previously disclosed that it is seeking a sale or restructuring of its interest in Eastern Energy and if these efforts are not successful, Eastern Energy may not be able to continue operations. As a result of the continued pressure on energy prices and negative forecasted operating cash flow and losses, management does not believe that cash flow from operations, together with available liquidity, will be sufficient to cover expected capital requirements or Eastern Energy s obligations, including, without limitation, its debt and certain lease obligations. For example, in July 2011, Eastern Energy made payments on certain lease obligations utilizing funds from a reserve account. The reserve account does not have sufficient funds to make the next payment which is due in January 2012. In addition, one of the holding companies has outstanding debt that came due as of July 6, 2011, which was used to cover normal operating activities. The holding company entered into an agreement with its lenders which provides forbearance for the past due payment, which expires on November 7, 2011. While discussions are continuing regarding an extension of the forbearance period there can be no assurance that an extension will be obtained. In the event that an extension is not granted, the holding company s lenders could foreclose on the holding company, including the shares of those subsidiaries which it owns, which could result in the loss of AES majority interest in those subsidiaries, which would result in a cross default on other debt and lease obligations. If Eastern Energy defaults on its debt or lease obligations, Eastern Energy could be subject to full payment of the outstanding principal or lease payments, accrued interest, termination costs under its lease arrangements and debt obligations, and other costs. In addition, as of March 31, 2011, we placed Eastern Energy into discontinued operations based on our intention to sell our interest in the business. We believe that the sale is probable of being consummated by March 31, 2012 for the business to continue to be presented as discontinued operations. However, while efforts to sell Eastern Energy continue, there can be no assurance that we will be able to sell our interest in Eastern Energy. If the Company s efforts to sell its interest in Eastern Energy fail, or the attempts to restructure Eastern Energy s obligations fail, Eastern Energy defaults on its debt, or it otherwise becomes clear that Eastern Energy cannot meet its future obligations, or Eastern Energy determines to file for bankruptcy and there could be a material impact on the Company and its results of operations. For example, it is possible that in prior periods, Eastern Energy may no longer be classified as discontinued operations and that the Company may be required to include Eastern Energy s losses in the Company s results of operations, which could have a material impact on those periods.

Global Economic Considerations. During the past few years, economic conditions in some countries where our subsidiaries conduct business have deteriorated. Global economic conditions remain volatile and could have an adverse impact on our businesses in the event these recent trends continue.

Our business or results of operations could be impacted if we or our subsidiaries are unable to access the capital markets on favorable terms or at all, are unable to raise funds through the sale of assets or are otherwise unable to finance or refinance our activities. At this time, the Euro Zone continues to face a sovereign debt crisis, the impacts of which are described below. The Company could also be adversely affected if capital market disruptions result in increased borrowing costs (including with respect to interest payments on the Company s or our subsidiaries variable rate debt) or if commodity prices affect the profitability of our plants or their ability to continue operations.

In addition, in recent months, global economic sentiment has indicated that there is a possibility of global economic slowdown in the coming months. The Company could be adversely affected if general economic or political conditions in the markets where our subsidiaries operate deteriorate, resulting in a reduction in cash flow from operations, a reduction in the availability and/or an increase in the cost of capital, or if the value of our assets remain depressed or decline further. Any of the foregoing events or a combination thereof could have a material impact on the Company, its results of operations, liquidity, financial covenants, and/or its credit rating.

Our subsidiaries are subject to credit risk, which includes risk related to the ability of counterparties (such as parties to our PPAs, fuel supply agreements, hedging agreements and other contractual arrangements) to deliver contracted commodities or services at the contracted price or to satisfy their financial or other contractual obligations. The Company has not suffered any material effects related to its counterparties during the nine months ended September 30, 2011. However, if macroeconomic conditions impact our counterparties, they may be unable to meet their commitments which could result in the loss of favorable contractual positions, which could have a material impact on our business.

In addition, during the past year, certain European Union countries have continually faced a sovereign debt crisis and it is possible that this crisis could spread to other countries. This crisis has resulted in an increased risk of default by governments and the implementation of austerity measures in certain countries. If the crisis continues, worsens, or spreads, there could be a material adverse impact on the Company. Our businesses may be impacted if they are unable to access the capital markets, face increased taxes or labor costs, or if governments fail to fulfill their obligations to us or adopt austerity measures which adversely impact our projects. In addition, as discussed in Item 1A. Risk Factors *Our renewable energy projects and other initiatives face considerable uncertainties including development, operational and regulatory challenges* of the 2010 Form 10-K, our renewables businesses are dependent on favorable regulatory incentives, including subsidies, which are provided by sovereign governments, including European governments. If these subsidies or other incentives are reduced or repealed, or sovereign governments are unable or unwilling to fulfill their commitments or maintain favorable regulatory incentives for renewables, in whole or in part, this could impact the ability of the affected businesses to continue to sustain and/or grow their operations. For example, in May 2011, the Spanish government issued a decree, which limits the feed-in-tariff and number of photovoltaic hours eligible for the feed-in-tariff. Similarly, the Italian government also published a decree in May 2011, which restricts the size of projects on agricultural land and replaced the old feed-in-tariff for projects not interconnected by May 31, 2011 with a new feed-in-tariff, resulting in an approximate 30% reduction to the current tariff. These decrees may have an adverse impact in Spain and Italy on AES Solar Energy Ltd., our international solar joint venture. For further information on the Spain decree, see Item 1. Regulatory Spain of the 2010 Form 10-K. In addition, any of the foregoing could also impact contractual counterparties of our subsidiaries in core power or renewables. If such counterparties are adversely impacted, then they may be unable to meet their commitments to our subsidiaries. For further information on the importance of long-term contracts and our counterparty credit risk, see Item 1A. Risk Factors *We may not be able to enter into long-term contracts, which reduce volatility in our results of operations* of the 2010 Form 10-K. As a result of any of the foregoing events, we may have to provide loans or equity to support affected businesses or projects, restructure them, write down their value and/or face the possibility that these projects cannot continue operations or provide returns consistent with our expectations, any of which could have a material impact on the Company. The Company s investment in AES Solar Energy Ltd., whose primary operations are in Europe, was $243 million at September 30, 2011. During the nine months ended September 30, 2011, in connection with the Italian decree noted above, AES Solar Energy Ltd. recognized an impairment of $20 million on its assets, of which AES s share was $10 million.

As noted in Item 7 Management s Discussion and Analysis, Key Drivers of Results in 2010, and Item 7A. Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk of the 2010 Form 10-K, the Company s North American businesses continue to face pressure as a result of high coal prices relative to natural gas, which has affected the results of certain of our coal plants in the region, particularly those which are merchant plants that are exposed to market risk and those that have hybrid merchant risk, meaning those businesses that have a PPA in place, but purchase fuel at market prices or under short term contracts. On February 1, 2011, AES Thames, LLC (Thames), our 208 MW coal-fired plant in Connecticut, filed petitions for bankruptcy protection under Chapter 11 in the U. S. Bankruptcy Court. In addition, as disclosed in *Key Trends and Uncertainties, Sale of Eastern Energy*, while our efforts to sell Eastern Energy continue, there can be no assurance that we will be successful in those efforts. At this time, AES Deepwater has been idled to mitigate operating risks caused by high fuel costs and other competitive pressures. If the conditions describe above continue or worsen, our North American businesses with market or hybrid merchant exposure may need to restructure their obligations or seek additional funding (including from the Parent) or face the possibility that they may be unable to meet their obligations and continue operations, which could result in the loss of earnings or cash flow or result in a write down in the value of these assets, any of which could have a material impact on the Company. For further discussion of the risks associated with commodity prices, see We may not be adequately hedged against our exposure to changes in commodity prices or interest rates in Item 1A. Risk Factors of the 2010 Form 10-K.

If global economic conditions worsen, it could also affect the prices we receive for the electricity we generate or transmit. Utility regulators or parties to our generation contracts may seek to lower our prices based on prevailing market conditions as PPAs, concession agreements or other contracts come up for renewal or reset. In addition, rising fuel and other costs coupled with contractual price or tariff decreases could restrict our ability to operate profitably in a given market. Each of these factors, as well as those discussed above, could result in a decline in the value of our assets including those at the businesses we operate, our equity investments and projects under development and could result in asset impairments that could be material to our operations. We continue to monitor our projects and businesses.

Table of Contents

Impairments.

Long-lived assets. The global economic conditions and other adverse factors discussed above heighten the risk of a significant asset impairment. Examples of conditions that could be indicative of impairment which would require us to evaluate the recovery of a long-lived asset or asset group include:

- current period operating or cash flow losses combined with a history of operating or cash flow losses or a projection that demonstrates continuing losses associated with the use of a long-lived asset group;
- a significant adverse change in legal factors, including changes in environmental or other regulations or in the business climate that could affect the value of a long-lived asset group, including an adverse action or assessment by a regulator;
- a significant adverse change in the extent or manner in which a long-lived asset group is being used or in its physical condition; and
- a current expectation that, more likely than not, a long-lived asset (asset group) will be sold or otherwise disposed of significantly before the end of its previously estimated useful life.

During the third quarter of 2011, the Company evaluated the future use of certain wind turbines held in storage pending their installation. Due to reduced wind turbine market pricing and advances in turbine technology, the Company determined that it was more likely that not the turbines would be sold significantly before the end of their previously estimated useful lives. At the same time, the Company also concluded that more likely than not non-refundable deposits that it had made in prior years to a turbine manufacturer for the purchase of wind turbines were not recoverable. The Company determined it was more likely than not that it would not proceed with the purchase of turbines due to the availability of more advanced and lower cost turbines in the market. In October 2011, the Company determined that an impairment had occured as of September 30, 2011 and wrote down the aggregate carrying amount of $161 million of these assets to their estimated fair value of $45 million by recognizing asset impairment expense of $116 million. It is reasonably possible that the turbines could incur further loss in value due to changing marketing conditions and advances in technology.

The prices for emission reduction offsets, including Certified Emission Reductions (CERs) and European Allowance Units (EUAs), have trended downward during 2011. This decline adversely impacted the Company s Carbon Reduction Projects in Asia and Latin America. The Latin American project also incurred current period operating losses and is projecting continuing operating and cash flow losses for future periods. The aggregate carrying amount of $49 million of these projects was written down as their estimated fair value was $11 million, resulting in asset impairment expense of $33 million, which was limited to the carrying amount of long-lived assets. It is reasonably possible that the prices of CERs and EUAs could decrease further and require the Company to record additional impairment expense.

We have continued to evaluate the recoverability of our long-lived assets at Kelanitissa, our diesel-fired generation plant in Sri Lanka, as a result of both the existing government regulation which may require the government to acquire an ownership interest and the current expectation of future losses. Our evaluation during the second quarter of 2011 indicated that the long-lived assets were not recoverable and accordingly, they were written down to their estimated fair value of $33 million based on a discounted cash flow analysis. An additional impairment of $4 million was recognized in the three months ended September 30, 2011. Kelanitissa is a Build-operate-transfer (BOT) generation facility and payments under its PPA are scheduled to decline over the PPA term. It is possible that further impairment charges may be required in the future as Kelanitissa gets closer to the BOT date.

Equity method investments. Adverse changes in economic and business conditions could also impact the value of our equity method investments. For example, YangCheng, our 2100 MW coal-fired plant in China, continues to experience lower operating margin due to higher coal prices. The coal prices have trended upward during the nine months ended September 30, 2011 and it is unlikely that the trend will reverse in the next several

Table of Contents

years. Due to the tight governmental control on tariff, it is also difficult to pass through the increase in fuel costs to customers. At the end of the venture in 2016, AES is required to surrender its interest to other venture partners without additional compensation. During the third quarter of 2011, an other-than-temporary-impairment of $74 million was recorded to write down YangCheng to its estimated fair value of $26 million. It is reasonably possible that further impairment expense may be required on YangCheng or any other equity method investments if adverse changes occur in economic or business environments.

Goodwill. The Company seeks business acquisitions as one of its growth strategies. We have achieved significant growth in the past as a result of several business acquisitions, which also resulted in the recognition of goodwill. As noted in Item 1A. Risk Factors of the 2010 Form 10-K, there is always a risk that *Our acquisitions may not perform as expected.* The benefits of goodwill are typically realized through the future operating results of an acquired business. Management believes that the recoverability of goodwill is positively correlated with the economic environments in which our acquired businesses operate and a severe economic downturn could negatively impact the recoverability of goodwill. Also, the evolving environmental regulations, including GHG regulations, around the globe continue to increase the operating costs of our generation businesses. In extreme situations, the environmental regulations could even make a once profitable business uneconomical. In addition, most of our generation businesses have a finite life and as the acquired businesses reach the end of their finite lives, the carrying amount of goodwill is gradually recovered through their periodic operating results. The accounting guidance, however, prohibits the systematic amortization of goodwill and rather requires an annual impairment evaluation. Thus, as some of our acquired businesses approach the end of their finite lives, they may incur goodwill impairment charges even if there are no discrete adverse changes in the economic environment.

In the fourth quarter of 2010, the Company completed its annual goodwill impairment evaluation and did not have any reporting units that were considered at risk. A reporting unit is considered at risk when its fair value is not higher than its carrying amount by more than 10%. While there were no potential impairment indicators at that time that could result in the recognition of goodwill impairment at our reporting units, it is possible we may incur goodwill impairment at our reporting units in future periods if any of the following events occur: a significant adverse change in business climate or legal factors, an adverse action or assessment by a regulator, a sale of assets at less than carrying amount, unanticipated competition, a loss of key personnel, an acquisition not performing as expected, changing environmental regulations that significantly increase the cost of doing business, or a business reaches the end of its finite life. The likelihood of the occurrence of these events may increase if global economic conditions remain volatile or deteriorate further. For example, during the third quarter of 2011, the Company identified higher coal prices and the resulting reduced operating margins in China as an impairment indicator of goodwill at Chigen, our holding company that holds AES interests in Chinese joint ventures. An interim evaluation of goodwill was performed at September 30, 2011 and its entire carrying amount of $17 million was recognized as a goodwill impairment. See Note 14 Impairment Expense to Item 1. Financial Statements for further information.

Regulatory Environment. The Company is subject to numerous environmental laws and regulations in the jurisdictions in which it operates. The Company expenses environmental regulation compliance costs as incurred unless the underlying expenditure qualifies for capitalization under its property, plant and equipment policies. The Company faces certain risks and uncertainties related to these environmental laws and regulations, including existing and potential greenhouse gas (GHG) legislation or regulations, and actual or potential laws and regulations pertaining to water discharges, waste management (including disposal of coal combustion byproducts), and certain air emissions, such as SO_2, NO_x, particulate matter and mercury. Such risks and uncertainties could result in increased capital expenditures or other compliance costs which could have a material adverse effect on certain of our U.S. or international subsidiaries and our consolidated results of operations. For further information about these risks, see Item 1A. Risk Factors, *Our businesses are subject to stringent environmental laws and regulations*, *Our businesses are subject to enforcement initiatives from environmental regulatory agencies,* and *Regulators, politicians, non-governmental organizations and other private parties have expressed concern about greenhouse gas, or GHG, emissions and the potential risks associated with*

Table of Contents

climate change and are taking actions which could have a material adverse impact on our consolidated results of operations, financial condition and cash flows set forth in the Company s Form 10-K for the year ended December 31, 2010.

Legislation and Regulation of GHG Emissions

Currently, in the United States there is no federal legislation establishing mandatory GHG emissions reduction programs (including CO_2) affecting the electric power generation facilities of the Company s subsidiaries. There are numerous state programs regulating GHG emissions from electric power generation facilities and there is a possibility that federal GHG legislation will be enacted within the next several years. Further, the United States Environmental Protection Agency (EPA) has adopted regulations pertaining to GHG emissions and has announced its intention to propose new regulations for electric generating units under Section 111 of the United States Clean Air Act (CAA).

Potential U.S. Federal GHG Legislation Federal legislation passed the U.S. House of Representatives in 2009 that, if adopted, would have imposed a nationwide cap-and-trade program to reduce GHG emissions. This legislation was never signed into law, and is no longer under consideration. In the U.S. Senate, several different draft bills pertaining to GHG legislation have been considered, including comprehensive GHG legislation similar to the legislation that passed the U.S. House of Representatives and more limited legislation focusing only on the utility and electric generation industry. It is uncertain whether any legislation pertaining to GHG emissions will be voted on and passed by the U.S. Senate and House of Representatives. If any such legislation is enacted into law, the impact could be material to the Company.

EPA GHG Regulation The EPA has promulgated regulations governing GHG emissions from automobiles under the CAA. The effect of the EPA s regulation of GHG emissions from mobile sources is that certain provisions of the CAA will also apply to GHG emissions from existing stationary sources, including many U.S. power plants. In particular, beginning January 2, 2011, construction of new stationary sources and modifications to existing stationary sources that result in increased GHG emissions became subject to permitting requirements under the prevention of significant deterioration (PSD) program of the CAA. The PSD program, as currently applicable to GHG emissions, requires sources that emit above a certain threshold of GHGs to obtain PSD permits prior to commencement of new construction or modifications to existing facilities. In addition, major sources of GHG emissions may be required to amend, or obtain new, Title V air permits under the CAA to reflect any new applicable GHG emissions requirements for new construction or for modifications to existing facilities.

The EPA promulgated a final rule on June 3, 2010 (the Tailoring Rule) that sets thresholds for GHG emissions that would trigger PSD permitting requirements. The Tailoring Rule, which became effective in January of 2011, provides that sources already subject to PSD permitting requirements need to install Best Available Control Technology (BACT) for greenhouse gases if a proposed modification would result in the increase of more than 75,000 tons per year of GHG emissions. Also, under the Tailoring Rule, any new sources of GHG emissions that would emit over 100,000 tons per year of GHG emissions, in addition to any modification that would result in GHG emissions exceeding 75,000 tons per year, require PSD review and are subject to related permitting requirements. The EPA anticipates that it will adjust downward the permitting thresholds of 100,000 tons and 75,000 tons for new sources and modifications, respectively, in future rulemaking actions. The Tailoring Rule substantially reduces the number of sources subject to PSD requirements for GHG emissions and the number of sources required to obtain Title V air permits, although new thermal power plants may still be subject to PSD and Title V requirements because annual GHG emissions from such plants typically far exceed the 100,000 ton threshold noted above. The 75,000 ton threshold for increased GHG emissions from modifications to existing sources may reduce the likelihood that future modifications to plants owned by some of our United States subsidiaries would trigger PSD requirements, although some projects that would expand capacity or electric output are likely to exceed this threshold, and in any such cases the capital expenditures necessary to comply with the PSD requirements could be significant.

Table of Contents

In December 2010, the EPA entered into a settlement agreement with several states and environmental groups to resolve a petition for review challenging the EPA s new source performance standards (NSPS) rulemaking for electric utility steam generating units (EUSGUs) based on the NSPS s failure to address GHG emissions. Under the settlement agreement, the EPA had committed to propose GHG emissions standards for EUSGUs by July 26, 2011. The EPA previously announced that it would delay the proposal of such standards until September 30, 2011, and it subsequently announced a further delay without specifying a deadline for the proposal of such standards. The EPA has also committed to finalize GHG NSPS for EUSGUs by May 26, 2012. The NSPS will establish GHG emission standards for newly constructed and reconstructed EUSGUs. The NSPS also will establish guidelines regarding the best system for achieving further GHG emissions reductions from existing EUSGUs. Based on the guidelines, individual states will be required to develop regulations establishing GHG performance standards for existing EUSGUs within their states. It is impossible to estimate the impact and compliance cost associated with any future NSPS applicable to EUSGUs until such regulations are finalized. However, the compliance costs could have a material and adverse impact on our consolidated financial condition or results of operations.

Regional Greenhouse Gas Initiative To date, the primary regulation of GHG emissions affecting the Company s U.S. plants has been through the Regional Greenhouse Gas Initiative (RGGI). Under RGGI, ten northeastern states have coordinated to establish rules that require reductions in CO_2 emissions from power plant operations within those states through a cap-and-trade program. States participating in RGGI in which our subsidiaries have generating facilities include Connecticut, Maryland, New York and New Jersey. Under RGGI, power plants must acquire one carbon allowance through auction or in the emission trading markets for each ton of CO_2 emitted. As noted in the Company s most recent Form 10-Q, we have estimated the costs to the Company of compliance with RGGI to be approximately $15 million for 2011.

International GHG Regulation The primary international agreement concerning GHG emissions is the Kyoto Protocol, which became effective on February 16, 2005 and requires the industrialized countries that have ratified it to significantly reduce their GHG emissions. The vast majority of the developing countries which have ratified the Kyoto Protocol have no GHG emissions reduction requirements. Many of the countries in which the Company s subsidiaries operate have no emissions reduction obligations under the Kyoto Protocol. In addition, of the 27 countries in which the Company s subsidiaries operate, all but one the United States (including Puerto Rico) have ratified the Kyoto Protocol. The first commitment period under the Kyoto Protocol is currently expected to expire at the end of 2012, and countries have been unable to agree on a successor commitment period. The next annual United Nations conference to develop a successor international agreement is scheduled for November 2011 in South Africa. It currently appears unlikely that a successor agreement will be reached at such conference; however, if a successor agreement is reached the impact could be material to the Company.

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

Table of Contents

Other U.S. Air Emissions Regulations and Legislation

The Company s subsidiaries in the United States are subject to the Clean Air Act (CAA) and various state laws and regulations that regulate emissions of air pollutants, including SO_2, NO_X, particulate matter (PM), mercury and other hazardous air pollutants (HAPs).

The EPA promulgated the Clean Air Interstate Rule (CAIR) on March 10, 2005, which 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 was subsequently challenged in federal court, and on July 11, 2008, the United States Court of Appeals for the D.C. Circuit issued an opinion striking down much of CAIR and remanding it to the EPA. In response to the D.C. Circuit s opinion, on July 7, 2011, the EPA issued a final rule titled Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States, which is now referred to as the Cross-State Air Pollution Rule (CSAPR). Starting in 2012, the CSAPR requires significant reductions in SO_2 and NO_x emissions from covered sources, such as power plants, in many states in which subsidiaries of the Company operate. Once fully implemented in 2014, the rule requires additional SO_2 emission reductions of 73% and additional NO_x reductions of 54% from 2005 levels. The CSAPR will be implemented, in part, through a market-based program under which compliance may be achievable through the acquisition and use of new emissions allowances that the EPA will create. The CSAPR contemplates limited interstate and intra-state trading of emissions allowances by covered sources. Initially, at least through 2012, the EPA will issue emissions allowances to affected power plants based on state emissions budgets established by the EPA under the CSAPR. The availability of and cost to purchase allowances to meet the emission reduction requirements is uncertain at this time. The CSAPR was published in the Federal Register on August 8, 2011 and on October 6, 2011, the EPA proposed some technical revisions to the CSAPR, including allowing for additional allowances for certain states. The EPA will be taking public comments on the proposed revisions for thirty days, and such public comments will be considered by the EPA prior to promulgating a final rule. Many states, utilities and other affected parties have filed lawsuits in the U.S. Court of Appeals for the District of Columbia seeking to stay the implementation of the CSAPR and challenging the validity of the CSAPR. We cannot predict the outcome of such litigation or the effect it might have on the possible implementation of the CSAPR. To comply with the CSAPR, additional pollution control technology may be required by some of our subsidiaries, and the cost of implementing any such technology could affect the financial condition or results of operations of these subsidiaries or the Company. Additionally, compliance with the CSAPR could require the purchase of newly issued allowances, the switch to higher priced, lower sulfur coal or the retirement of existing generating units. While the capital costs, other expenditures or operational restrictions necessary to comply with the CSAPR cannot be specified at this time, and the outcome of litigation pertaining to CSAPR is uncertain, the Company anticipates that the CSAPR may have a material impact on the Company s business and results of operations.

As a result of prior EPA determinations and the D.C. Circuit Court ruling, the EPA is obligated under Section 112 of the CAA to develop a rule requiring pollution controls for hazardous air pollutants, including mercury, hydrogen chloride, hydrogen fluoride, and other metal species from coal and oil-fired power plants. The EPA has entered into a consent decree under which it is obligated to finalize the rule by November 2011, and it has subsequently requested an extension of this deadline until December 16, 2011. In connection with such rule, the CAA requires the EPA to establish maximum achievable control technology (MACT) standards for each pollutant regulated under the rule. MACT is defined as the emission limitation achieved by the best performing 12% of sources in the source category. The EPA published a proposed rule on May 3, 2011 that would establish national emissions standards for hazardous air pollutants (NESHAP) from coal- and oil-fired electric utility steam generating units. The rule, as currently proposed, may require all coal-fired power plants to retire operations or install acid gas control technology, upgrade particulate control devices and/or install some other type of mercury control technology, such as sorbent injection. The public comment period for this proposed rule has expired, and the public comments will be considered by the EPA prior to promulgating a final rule. Most of the United States coal-fired plants operated by the Company s subsidiaries have acid gas scrubbers or comparable control technologies, but as proposed there are other improvements to such control technologies that may be needed at some of the Company s plants. Under the CAA, compliance is required within three years of

Table of Contents

the effective date of the rule; however, the compliance period for a unit, or group of units, may be extended by state permitting authorities (for one additional year) or through a determination by the President (for up to two additional years). At this time, the Company cannot predict the extent of the final regulations for hazardous air pollutants, but the cost of compliance with any such regulations could be material.

Other International Air Emissions Regulations and Legislation

On January 18, 2011, the President of Chile approved a new air emissions regulation submitted to him by the national environmental regulatory agency (CONAMA). The new regulation establishes limits on emissions of NO_x, SO_2, metals and particulate matter for both existing and new thermal power plants, with more stringent limitations on new facilities. The regulation became effective on June 23, 2011. The regulation will require AES Gener, the Company s Chilean subsidiary, to install emissions reduction equipment at its existing thermal plants from late 2011 through 2015. The costs of compliance with such regulation have not yet been determined and the Company believes some of the compliance costs are contractually passed through to counterparties. However, the compliance costs could be material.

Cooling Water Intake Regulations

The Company s U.S. facilities are subject to the U.S. Clean Water Act Section 316(b) rule issued by the EPA which seeks to protect fish and other aquatic organisms by requiring existing steam electric generating facilities to utilize the best technology available for cooling water intake structures. The EPA published a proposed rule establishing requirements under 316(b) regulations on April 20, 2011. The proposal, based on Section 316(b) of the U.S. Clean Water Act, establishes Best Technology Available (BTA) requirements regarding impingement standards with respect to aquatic organisms for all facilities that withdraw above 2 million gallons per day of water from certain water bodies and utilize at least 25% of the withdrawn water for cooling purposes. To meet these BTA requirements, as currently proposed, cooling water intake structures associated with once through cooling processes will need modifications of existing traveling screens that protect aquatic organisms and will need to add a fish return and handling system for each cooling system. Existing closed cycle cooling facilities may require upgrades to water intake structure systems. The proposal would also require comprehensive site-specific studies during the permitting process and may require closed-cycle cooling systems in order to meet BTA entrainment standards.

The public comment period for this proposed rule has expired, and the EPA will consider the public comments with a view to issuing a final rule by July of 2012. 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 protecting fish and other aquatic organisms 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. On September 27, 2010, the California Office of Administrative Law approved a policy adopted by the California Water Resources Control Board with respect to power plant cooling water intake structures. This policy became effective on October 1, 2010, and establishes technology-based standards to implement Section 316(b) of the U.S. Clean Water Act. At this time, it is contemplated that the Company s Redondo Beach, Huntington Beach and Alamitos power plants in California will need to have in place best technology available by December 31, 2020, or repower the facilities. 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, many of the Company s facilities generate coal combustion byproducts (CCB), including fly ash, requiring disposal or processing. On June 21, 2010 the EPA published in the Federal Register a proposed rule to regulate CCB under the Resource Conservation and Recovery Act (RCRA). The

Table of Contents

proposed rule provides two possible options for CCB regulation, and both options contemplate heightened structural integrity requirements for surface impoundments of CCB. The first option contemplates regulation of CCB as a hazardous waste subject to regulation under Subtitle C of the RCRA. Under this option, existing surface impoundments containing CCB would be required to be retrofitted with composite liners and these impoundments would likely be phased out over several years. State and/or federal permit programs would be developed for storage, transport and disposal of CCB. States could bring enforcement actions for non-compliance with permitting requirements, and the EPA would have oversight responsibilities as well as the authority to bring lawsuits for non-compliance. The second option contemplates regulation of CCB under Subtitle D of the RCRA. Under this option, the EPA would create national criteria applicable to CCB landfills and surface impoundments. Existing impoundments would also be required to be retrofitted with composite liners and would likely be phased out over several years. This option would not contain federal or state permitting requirements. The primary enforcement mechanism under regulation pursuant to Subtitle D would be private lawsuits.

The public comment period for this proposed regulation has expired, and the EPA is required to consider the public comments prior to promulgating a final rule. Requirements under a final rule are expected to become effective by January 2012, with a compliance schedule of five years. While the exact impact and compliance cost associated with future regulations of CCB cannot be established until such regulations are finalized, there can be no assurance that the Company s businesses, financial condition or results of operations would not be materially and adversely affected by such regulations.

Indiana Senate Bill 251

In May 2011, Senate Bill 251 became a law in the State of Indiana. Senate Bill 251 is a comprehensive bill which, among other things, provides Indiana utilities, including IPL, with a means for recovering 80% of costs incurred to comply with federal mandates through a periodic retail rate adjustment mechanism, and additional cost recovery is possible through a subsequent general rate case. This includes costs to comply with regulations from the EPA, FERC, NERC, the Department of Energy, etc., including capital intensive requirements and/or proposals such as those relating to cooling water intake regulations, waste management and coal combustion byproducts, wastewater effluent, MISO transmission expansion costs and polychlorinated biphenyls. It does not change existing legislation that allows for 100% recovery of clean coal technology designed to reduce air pollutants (Indiana Senate Bill 29).

Some of the most important features of Senate Bill 251 to IPL are as follows: any energy utility in Indiana seeking to recover federally mandated costs incurred in connection with a compliance project shall apply to the Indiana Utility Regulatory Commission (IURC) for a certificate of public convenience and necessity (CPCN) for the compliance project. It sets forth certain factors that the IURC must consider in determining whether to grant a CPCN. It further specifies that if the IURC approves a proposed compliance project and the projected federally mandated costs associated with the project, the following apply: (i) 80% of the approved costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism; (ii) 20% of the approved costs shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the IURC; and (iii) actual costs exceeding the projected federally mandated costs of the approved compliance project by more than 25% shall require specific justification and approval by the IURC before being authorized in the energy utility s next general rate case.

Recent Events

On October 20, 2011, a subsidiary of the Company signed a share sale agreement with Electrabel International Holdings B.V. (EIH), a subsidiary of GDF SUEZ S.A. (GDFS) for the sale of 80% of its interest in the wholly-owned holding company that holds the Company s interest in AES Energia Cartagena S.R.L. (AES Cartagena), a 1,199 MW gas-fired generation business in Spain, for 172 million ($234 million), subject to customary purchase price adjustments. AES owns approximately 70.81% of AES Cartagena through this holding company structure. Under the terms of the sale agreement, EIH has an option to purchase AES remaining 20% interest in the holding company for a fixed price of 28 million ($38 million) during a five month period beginning 13 months from the date the sale closes. Subject to regulatory and lenders approvals, the sale is expected to close by the end of 2011. Concurrent with the sale, GDFS agreed to settle the outstanding arbitration between the parties regarding certain emissions costs and other taxes that AES Cartagena sought to recover from GDFS as energy manager under the existing commercial arrangements and to pay 58 million ($79 million) to AES Cartagena for such costs incurred by AES Cartagena during the period up to December 31, 2010 and additional amounts for such costs incurred by AES Cartagena during the period from January 1, 2011 until closing of the sale. However, the settlement of the arbitration is contingent on consummation of the sale. See Note 9 *Contingencies and Commitments* for further information.

In July 2011, a subsidiary of the Company entered into an agreement to sell its ownership interest in two telecommunication companies in Brazil. The Company held approximately 46% ownership interest in these companies through the subsidiary. The transaction closed on October 31, 2011 and the subsidiary received approximately R$1,522 million ($901 million), subject to customary purchase price adjustments. The estimated gain on the sale before noncontrolling interests and taxes is approximately R$1,333 million ($789 million), subject to final purchase price adjustments.

On October 3, 2011, the Company completed the placement of $1.25 billion aggregate principal amount senior notes with Wells Fargo Bank N.A. See Note 8 *Debt, Non-Recourse Debt* for further information.

Subsequent to September 30, 2011, the Company continued to repurchase stock under the stock repurchase program announced on July 7, 2010. The Company has repurchased 5,554,185 shares at a cost of $54 million subsequent to September 30, 2011, bringing the cumulative total through November 3, 2011 to 33,924,805 shares at a total cost of $378 million (average price of $11.16 per share including commissions). For additional information, see Note 11 *Equity*.

Table of Contents

Consolidated Results of Operations

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011	2010	$ change	% change	2011	2010	$ change	% change
	(in millions, except per share amounts)				(in millions, except per share amounts)			
Revenue:								
Latin America Generation	$ 1,302	$ 1,111	$ 191	17%	$ 3,810	$ 3,178	$ 632	20%
Latin America Utilities	1,930	1,757	173	10%	5,774	5,236	538	10%
North America Generation	372	413	(41)	-10%	1,116	1,173	(57)	-5%
North America Utilities	321	306	15	5%	890	869	21	2%
Europe Generation	397	282	115	41%	1,125	864	261	30%
Asia Generation	172	136	36	26%	449	491	(42)	-9%
Corporate and Other(1)	215	252	(37)	-15%	800	744	56	8%
Eliminations(2)	(328)	(267)	(61)	-23%	(847)	(778)	(69)	-9%
Total Revenue	$ 4,381	$ 3,990	$ 391	10%	$ 13,117	$ 11,777	$ 1,340	11%
Gross Margin:								
Latin America Generation	$ 440	$ 386	$ 54	14%	$ 1,308	$ 1,145	$ 163	14%
Latin America Utilities	305	247	58	23%	810	714	96	13%
North America Generation	110	111	(1)	-1%	301	300	1	-%
North America Utilities	71	78	(7)	-9%	170	206	(36)	-17%
Europe Generation	95	47	48	102%	240	221	19	9%
Asia Generation	38	52	(14)	-27%	136	197	(61)	-31%
Corporate and Other(3)	(37)	33	(70)	-212%	37	85	(48)	-56%
Eliminations(4)	(2)	13	(15)	-115%	17	33	(16)	-48%
General and administrative	(91)	(98)	7	7%	(283)	(279)	(4)	-1%
Interest expense	(432)	(381)	(51)	-13%	(1,178)	(1,151)	(27)	-2%
Interest income	103	96	7	7%	293	304	(11)	-4%
Other expense	(76)	(23)	(53)	-230%	(131)	(83)	(48)	-58%
Other income	58	17	41	241%	108	94	14	15%
Gain on sale of investments	-	-	-	-%	7	-	7	100%
Goodwill impairment	(17)	(18)	1	-6%	(17)	(18)	1	6%
Asset impairment expense	(163)	(296)	133	45%	(196)	(297)	101	34%
Foreign currency transaction gains (losses) on net monetary position	(92)	103	(195)	-189%	(21)	(19)	(2)	-11%
Other non-operating expense	(82)	(2)	(80)	-4000%	(82)	(7)	(75)	-1071%
Income tax expense	(84)	(102)	18	18%	(469)	(540)	71	13%
Net equity in earnings of affiliates	6	26	(20)	-77%	12	174	(162)	-93%
Income from continuing operations	150	289	(139)	-48%	1,062	1,079	(17)	-2%
Income from operations of discontinued businesses	25	29	(4)	-14%	23	92	(69)	-75%
Gain from disposal of discontinued businesses	-	79	(79)	-100%	-	57	(57)	-100%
Net income	175	397	(222)	-56%	1,085	1,228	(143)	-12%
Noncontrolling interests:								
Income from continuing operations attributable to noncontrolling interests	(269)	(248)	(21)	-8%	(766)	(725)	(41)	-6%
Income from discontinued operations attributable to noncontrolling interests	(37)	(35)	(2)	-6%	(52)	(58)	6	10%
Net (loss) income attributable to The AES Corporation	$ (131)	$ 114	$ (245)	-215%	$ 267	$ 445	$ (178)	-40%
Per Share Data:								
Basic (loss) income per share from continuing operations	$ (0.15)	$ 0.05	$ (0.20)	-400%	$ 0.38	$ 0.46	$ (0.08)	-17%
Diluted (loss) income per share from continuing operations	$ (0.15)	$ 0.05	$ (0.20)	-400%	$ 0.38	$ 0.46	$ (0.08)	-17%

(1) Corporate and Other includes revenue from our generation and utilities businesses in Africa, utilities businesses in Europe, Wind Generation and other renewables initiatives.
(2) Represents inter-segment eliminations of revenue primarily related to transfers of electricity from Tietê (generation) to Eletropaulo (utility).
(3) Corporate and Other gross margin includes gross margin from our generation and utilities businesses in Africa, utilities businesses in Europe, Wind Generation and other renewables initiatives.
(4) Represents inter-segment eliminations of gross margin related to corporate charges for self insurance premiums.

Table of Contents

Segment Analysis

Latin America

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

	For the Three Months Ended September 30,			For the Nine Months Ended September 30,		
	2011	2010	% Change	2011	2010	% Change
	($ s in millions)			($ s in millions)		
Latin America Generation						
Revenue	$ 1,302	$ 1,111	17%	$ 3,810	$ 3,178	20%
Gross Margin	$ 440	$ 386	14%	$ 1,308	$ 1,145	14%

Excluding the favorable impact of foreign currency translation and remeasurement of $8 million, generation revenue for the three months ended September 30, 2011 increased $183 million, or 16%, compared to the three months ended September 30, 2010 primarily due to:

higher energy prices of $54 million attributable to a price adjustment for consuming an alternate fuel and $9 million associated with higher availability in Argentina;

new business of $37 million at Angamos, Gener s 264 MW coal-fired plant in Chile, which commenced commercial operations in April 2011;

higher revenue of $29 million at Tietê in Brazil due to the combined effect of higher contract prices associated with CPI indexation in the second half of 2011 and higher volume due to an increase in energy demand in Brazil;

higher contract prices of $26 million at Gener in Chile as a result of price indexation mainly driven by higher fuel costs;

higher ancillary services and third party gas sales of $17 million, and higher energy prices of $13 million primarily from PPAs in the Dominican Republic; and

higher volume of $16 million in Colombia and Panama driven by higher generation mainly due to higher water inflows in the system.

These increases were partially offset by:

lower generation volume of $25 million in Argentina due to reduced capacity of the plant to operate on alternate fuel; and

lower spot prices of $13 million in Colombia and Panama due to higher water inflows in the system.

Excluding the favorable impact of foreign currency translation and remeasurement of $15 million, primarily in Brazil, generation gross margin for the three months ended September 30, 2011 increased $39 million, or 10%, compared to the three months ended September 30, 2010 primarily due to:

higher volume of $44 million at Gener Electrica Santiago primarily associated with higher spot sales and improved fuel availability;

higher volume and contract energy prices at Tietê of $32 million as result of higher energy demand and CPI indexation in the second half of 2011;

higher volume of $24 million in Colombia and Panama as a result of higher generation;

- higher ancillary services and gas sales of $12 million and higher energy prices of $7 million in the Dominican Republic as mentioned above;

- higher energy prices of $7 million at a coal generation business in Argentina as a result of higher thermal generation with alternate fuel; and

- new business of $4 million at Angamos as described above.

These increases were partially offset by:

- higher fuel costs at Gener in Chile of $21 million;

- a net decrease of $22 million related to higher spot purchases and the forced outage in Panama;

- lower generation volume of $13 million in Argentina due to reduced capacity of the plant to operate on alternate fuel;

- lower spot prices of $13 million in Colombia and Panama due to higher water inflows in the system; and

- higher fixed and operating costs of $20 million across the region, primarily attributable to higher maintenance costs as well as higher depreciation at Tietê due to the change in useful lives and salvage values of property, plant and equipment, as a result of new regulatory information.

For the three months ended September 30, 2011, revenue increased 17%, while gross margin increased by 14%. This was primarily due to the higher spot purchases in Panama resulting from the forced outage, and the price adjustment in Argentina for consuming an alternate fuel that had no corresponding impact on gross margin and higher fixed costs.

Excluding the favorable impact of foreign currency translation and remeasurement of $44 million, generation revenue for the nine months ended September 30, 2011 increased $588 million, or 19%, compared to the nine months ended September 30, 2010 primarily due to:

- higher energy prices of $200 million in Argentina attributable to a price adjustment for consuming an alternate fuel;

- higher contract and spot prices of $164 million at Gener as a result of low water inflows in the Central Interconnected System and PPA price indexation;

- new business of $109 million at Angamos;

- higher volume of $99 million in Colombia and Panama due to higher water inflows in the system during the first six months of 2011;

- higher volume of $70 million at Gener Electrica Santiago primarily associated with higher spot sales and improved fuel availability;

- higher contract prices of $40 million at Tietê due to CPI indexation in the second half of 2011; and

- higher contract prices of $34 million primarily from PPAs indexed to coal, higher ancillary services and higher third party gas sales of $38 million in the Dominican Republic.

These increases were partially offset by:

- lower spot prices of $123 million in Colombia and Panama due to higher water inflows in the system during the first six months of 2011;

Table of Contents

- lower volume of $32 million at Tietê mainly driven by reduced requirements per PPA settlement terms during the first six months of 2011;
- $32 million related to the final settlement of the power sales agreement between Uruguaiana and Sul in the second quarter of 2010; and
- a net decrease of $26 million related to the forced outage in Panama.

Excluding the favorable impact of foreign currency translation and remeasurement of $51 million, primarily in Brazil, generation gross margin for the nine months ended September 30, 2011 increased $112 million, or 10%, compared to the nine months ended September 30, 2010 primarily due to:

- higher volume of $127 million at Gener Electrica Santiago primarily associated with higher spot sales and improved fuel availability;
- higher volume of $115 million in Colombia and Panama as a result of higher water inflows in the system during the first six months of 2011;
- higher contract prices of $43 million at Tietê, as discussed above;
- higher contract and spot prices of $42 million at Gener as a result of low water inflows in the Central Interconnected System;
- new business of $41 million at Angamos, as described above;
- higher energy prices of $28 million and higher ancillary services and gas sales of $20 million in the Dominican Republic, as described above; and
- higher volume of $13 million at coal generation businesses in Argentina as a result of low hydrology.

These increases were partially offset by:

- lower spot prices of $110 million in Colombia and Panama due to higher water inflows in the system during the first six months of 2011;
- a net decrease of $82 million related to higher spot purchases and the forced outage in Panama;
- lower volume of $40 million at Tietê, as discussed above;
- $32 million related to the final settlement of the power sales agreement between Uruguaiana and Sul; and

higher fixed and operating costs of $71 million across the region, primarily attributable to higher employee costs, maintenance costs, increase in non-income taxes in Argentina and Colombia, and higher depreciation at Tietê due to the change in useful lives and salvage values of property, plant and equipment, as a result of new regulatory information.

For the nine months ended September 30, 2011, revenue increased 20%, while gross margin increased by 14%. This was primarily due to the higher spot purchases in Panama resulting from the forced outage, the price adjustment in Argentina for consuming an alternate fuel that had no corresponding impact on gross margin and higher fixed costs.

Table of Contents

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

	For the Three Months Ended September 30,			For the Nine Months Ended September 30,		
	2011	2010	% Change	2011	2010	% Change
		($ s in millions)			($ s in millions)	
Latin America Utilities						
Revenue	$ 1,930	$ 1,757	10%	$ 5,774	$ 5,236	10%
Gross Margin	$ 305	$ 247	23%	$ 810	$ 714	13%

Excluding the favorable impact of foreign currency translation of $122 million, primarily in Brazil, utilities revenue for the three months ended September 30, 2011 increased $51 million, or 3%, compared to the three months ended September 30, 2010 primarily due to:

- higher volume of $63 million, primarily in Brazil, due to increased market demand; and
- higher tariffs of $45 million at Sul in Brazil and our utility businesses in El Salvador primarily due to higher energy prices associated with energy purchases and pass-through transmission costs.

These increases were partially offset by:

- expected lower tariffs of $55 million at Eletropaulo in Brazil, primarily related to the estimated impact of the July 2011 tariff reset which has been postponed by the Brazilian energy regulatory agency.

Excluding the favorable impact of foreign currency translation of $27 million, primarily in Brazil, utilities gross margin for the three months ended September 30, 2011 increased $31 million, or 13%, compared to the three months ended September 30, 2010 primarily due to:

- lower fixed costs of $64 million primarily due to contingency reversals and a non-recurring reduction in bad debt expense in Brazil; and
- higher volume of $23 million, primarily in Brazil, due to increased market demand.

These increases were partially offset by:

- expected lower tariffs of $35 million at Eletropaulo in Brazil, primarily related to the estimated impact of the July 2011 tariff reset which has been postponed by the Brazilian energy regulatory agency; and
- higher depreciation of $11 million at our businesses in Brazil, mainly due to the change in useful lives and salvage values of property, plant and equipment, as a result of new regulatory information.

For the three months ended September 30, 2011, revenue increased 10%, while gross margin increased by 23%. This was primarily due to non-recurring lower fixed costs in Brazil.

Excluding the favorable impact of foreign currency translation of $446 million, primarily in Brazil, utilities revenue for the nine months ended September 30, 2011 increased $92 million, or 2%, compared to the nine months ended September 30, 2010 primarily due to:

higher volume of $223 million, primarily in Brazil, due to increased market demand; and

higher tariffs of $53 million at our utility businesses in El Salvador primarily due to higher energy prices associated with energy purchases and pass-through transmission costs.

These increases were partially offset by:

- lower tariffs of $153 million at Eletropaulo in Brazil, primarily related to the estimated impact of the July 2011 tariff reset which has been postponed by the Brazilian energy regulatory agency and lower energy prices associated with energy purchases and pass-through transmission costs.

Excluding the favorable impact of foreign currency translation of $76 million, primarily in Brazil, utilities gross margin for the nine months ended September 30, 2011 increased $20 million, or 3%, compared to the nine months ended September 30, 2010 primarily due to:

- higher volume of $118 million, primarily in Brazil, due to increased market demand;
- $32 million related to the final settlement of a power sales agreement between Sul and Uruguaiana in the second quarter of 2010; and
- lower fixed costs of $12 million, primarily in Brazil, due to contingency reversals and a non-recurring reduction in bad debt expense, partially offset by higher employee costs, regulatory penalties and maintenance costs.

These increases were partially offset by:

- lower tariffs of $94 million primarily related to the estimated impact of the July 2011 tariff reset at Eletropaulo which has been postponed by the Brazilian energy regulatory agency; and
- higher depreciation of $37 million at our businesses in Brazil, mainly due to the change in useful lives and salvage values of property, plant and equipment, as a result of new regulatory information.

North America

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

	For the Three Months Ended September 30,			For the Nine Months Ended September 30,		
	2011	2010	% Change	2011	2010	% Change
		($ s in millions)			($ s in millions)	
North America Generation						
Revenue	$ 372	$ 413	-10%	$ 1,116	$ 1,173	-5%
Gross Margin	$ 110	$ 111	-1%	$ 301	$ 300	0%

Excluding the favorable impact of foreign currency translation of $4 million in Mexico, generation revenue for the three months ended September 30, 2011 decreased $45 million, or 11%, compared to the three months ended September 30, 2010 primarily due to:

- a decrease of $27 million at Thames in Connecticut due to the plant shutdown in January 2011 and its deconsolidation as of February 2011 as a result of loss of control to the U.S. Bankruptcy Court for the District of Delaware when it filed for bankruptcy protection;
- a decrease of $8 million at Merida in Mexico due to a combination of forced and scheduled outages; and

a decrease in volume of $8 million at Deepwater in Texas due to the layup of the plant caused by high fuel costs and diminishing power prices.

Excluding the favorable impact of foreign currency translation of $1 million in Mexico, generation gross margin for the three months ended September 30, 2011 decreased $2 million, or 2%, compared to the three months ended September 30, 2010 primarily due to:

- a decrease of $8 million at TEG/TEP in Mexico due to management fee adjustments; and
- a decrease of $6 million at Merida due to a combination of forced and scheduled outages.

These decreases were partially offset by:

- an increase of $8 million in Hawaii due to a favorable impact of prior year mark-to-market derivative adjustments.

For the three months ended September 30, 2011, revenue decreased 10%, while gross margin decreased by 1%. This was primarily due to outages at Merida and Puerto Rico, which had a greater impact on revenue than gross margin.

Excluding the favorable impact of foreign currency translation of $15 million in Mexico, generation revenue for the nine months ended September 30, 2011 decreased $72 million, or 6%, compared to the nine months ended September 30, 2010 primarily due to:

- a net decrease of $69 million at Thames as discussed above;
- a decrease in volume of $21 million at Deepwater as discussed above; and
- decreases at Merida of $16 million due to lower rates, and volume and $8 million due to a combination of forced and scheduled outages.

These decreases were partially offset by:

- increases at Puerto Rico of $21 million primarily due to a prior year forced outage and related penalty and $13 million due to higher rates.

Excluding the favorable impact of foreign currency translation of $2 million in Mexico, generation gross margin for the nine months ended September 30, 2011 decreased $1 million, or 0%, compared to the nine months ended September 30, 2010 primarily due to:

- decreases of $14 million at TEG/TEP due to a combination of forced and scheduled outages and higher fuel costs and $8 million due to management fee adjustments;
- a decrease of $8 million at Shady Point in Oklahoma due to higher fuel costs;
- a decrease in volume of $7 million at Deepwater as discussed above; and
- a decrease of $7 million at Merida due to a combination of forced and scheduled outages.

These decreases were partially offset by:

- an increase in Puerto Rico of $15 million primarily due to a prior year forced outage and related penalty;
- an increase of $15 million in Hawaii due to a favorable impact of prior year mark-to-market derivative adjustments; and
- lower fixed costs at Deepwater of $7 million as discussed above.

Table of Contents

For the nine months ended September 30, 2011, revenue decreased 5%, while gross margin remained flat. This was primarily due to the favorable impact of the mark-to-market derivative gain in Hawaii as discussed above.

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

	For the Three Months Ended September 30,			For the Nine Months Ended September 30,		
	2011	2010	% Change	2011	2010	% Change
	($ s in millions)			($ s in millions)		
North America Utilities						
Revenue	$ 321	$ 306	5%	$ 890	$ 869	2%
Gross Margin	$ 71	$ 78	-9%	$ 170	$ 206	-17%

Utilities revenue for the three months ended September 30, 2011 increased $15 million, or 5%, compared to the three months ended September 30, 2010 primarily due to:

- higher prices of $19 million primarily due to higher fuel adjustment charges of $17 million.

This increase was partially offset by:

- lower retail volume of $4 million primarily due to unfavorable weather.

Utilities gross margin for the three months ended September 30, 2011 decreased $7 million, or 9%, compared to the three months ended September 30, 2010 primarily due to:

- higher outage costs of $4 million for repairs and maintenance on generating units.

For the three months ended September 30, 2011, revenue increased 5%, while gross margin decreased by 9% primarily due to the positive impact of higher pass-through fuel costs on revenue, which had no corresponding impact on gross margin.

Utilities revenue for the nine months ended September 30, 2011 increased $21 million, or 2%, compared to the nine months ended September 30, 2010 primarily due to:

- higher prices of $51 million, primarily due to higher fuel adjustment charges of $45 million.

This increase was partially offset by:

- lower wholesale volume of $17 million, primarily due to increased generating unit outages; and

- lower retail volume of $12 million, primarily due to unfavorable weather.

Utilities gross margin for the nine months ended September 30, 2011 decreased $36 million, or 17%, compared to the nine months ended September 30, 2010 primarily due to:

- lower wholesale margin of $11 million, primarily due to increased generating unit outages;

higher outage costs of $9 million for repairs and maintenance on generating units;

lower retail margin of $6 million, primarily due to a non-recurring charge to retail revenue in the first quarter of 2011 and unfavorable weather; and

Table of Contents

higher non-outage salaries, wages and benefits of $5 million, primarily due to increases in pension and health insurance expenses, as well as higher pay rates in 2011.

For the nine months ended September 30, 2011, revenue increased 2%, while gross margin decreased by 17% primarily due to the positive impact of higher pass-through fuel costs on revenue, which had no corresponding impact on gross margin, and increased maintenance costs due to outages.

Europe

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

	For the Three Months Ended September 30,			For the Nine Months Ended September 30,		
	2011	2010	% Change	2011	2010	% Change
		($ s in millions)			($ s in millions)	
Europe Generation						
Revenue	$ 397	$ 282	41%	$ 1,125	$ 864	30%
Gross Margin	$ 95	$ 47	102%	$ 240	$ 221	9%

Excluding the favorable impact of foreign currency translation of $24 million, generation revenue for the three months ended September 30, 2011 increased $91 million, or 32%, compared to the three months ended September 30, 2010 primarily due to:

new business of $77 million at Maritza, in Bulgaria, which commenced commercial operations in June 2011; and

a net increase of $49 million from the operations of Ballylumford, in Northern Ireland, which was acquired in August 2010.

These increases were partially offset by:

lower revenue of $27 million at Cartagena, primarily due to lower pass-through energy; and

lower revenue of $7 million at Kilroot, in Northern Ireland, primarily driven by the cancellation of the long-term PPA and related supplementary agreements in November 2010 and a subsidy for flue gas desulphurization (FGD) investment that ended in 2010, partially offset by increased energy prices and CO_2 contributions passed through in the market price.

Excluding the favorable impact of foreign currency translation of $6 million, generation gross margin for the three months ended September 30, 2011 increased $42 million, or 89%, compared to the three months ended September 30, 2010 primarily due to:

new business of $26 million at Maritza, which commenced commercial operations in June 2011, and $12 million from the reversal of fixed costs as a result of liquidated damages received from a subcontractor; and

a net increase of $16 million from the operations at Ballylumford, which was acquired in August 2010.

These increases were partially offset by:

a net decrease of $10 million at Kilroot primarily driven by the cancellation of the long-term PPA and related supplementary agreements in November 2010, lower volumes, and an increase in maintenance expense, partially offset by CO_2 contributions passed through in the market price; and

Table of Contents

- $9 million in Hungary, primarily from lower contract sales and lower volume on ancillary services, partially offset by higher capacity prices.

For the three months ended September 30, 2011, revenue increased 41%, while gross margin increased by 102% primarily due to the recovery of liquidated damages received from a subcontractor at Maritza, lower maintenance expense at Ballylumford, as the plant was under an outage in September 2010, lower pass-through revenue at Cartagena that had no corresponding impact on gross margin, and the reversal of bad debt in Kazakhstan.

Excluding the favorable impact of foreign currency translation of $58 million, generation revenue for the nine months ended September 30, 2011 increased $203 million, or 23%, compared to the nine months ended September 30, 2010 primarily due to:

- a net increase of $237 million from the operations of Ballylumford, which was acquired in August 2010; and
- new business of $107 million at Maritza, which commenced commercial operations in June 2011.

These increases were partially offset by:

- lower revenue of $76 million at Cartagena, primarily due to lower pass-through energy;
- lower revenue of $39 million at Kilroot, primarily driven by the cancellation of the long-term PPA and related supplementary agreements in November 2010; and
- a net decrease of $35 million in Hungary primarily from lower contract sales and lower volume on ancillary services, partially offset by higher capacity prices.

Excluding the favorable impact of foreign currency translation of $14 million, generation gross margin for the nine months ended September 30, 2011 increased $5 million, or 2%, compared to the nine months ended September 30, 2010 primarily due to:

- gross margin of $70 million from the operations at Ballylumford, which was acquired in August 2010; and
- gross margin of $27 million at Maritza, which commenced commercial operations in June 2011.

These increases were partially offset by:

- decreased gross margin of $60 million at Kilroot primarily driven by the cancellation of the long-term PPA and related supplementary agreements in November 2010, partially offset by CO_2 contributions passed through in the market price; and
- lower gross margin of $36 million in Hungary primarily due to a decline in contract energy prices and negative dark spread.

For the nine months ended September 30, 2011, revenue increased 30% while gross margin increased by 9% primarily due to the acquisition of Ballylumford, which had a larger positive impact on revenue than gross margin, higher energy revenues at Kilroot, which as a pass-through had no corresponding impact on gross margin, and increased fixed costs at Maritza due to delays in the commencement of commercial operations, partially offset by the reversal of liquidated damages at Maritza in July 2011 and the reversal of bad debt in Kazakhstan.

Table of Contents

Asia

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

	For the Three Months Ended September 30,			For the Nine Months Ended September 30,		
	2011	2010	% Change	2011	2010	% Change
		($ s in millions)			($ s in millions)	
Asia Generation						
Revenue	$ 172	$ 136	26%	$ 449	$ 491	-9%
Gross Margin	$ 38	$ 52	-27%	$ 136	$ 197	-31%

Excluding the favorable impact of foreign currency translation of $8 million, generation revenue for the three months ended September 30, 2011 increased $28 million, or 21%, compared to the three months ended September 30, 2010 primarily due to:

- higher generation volume of $27 million at Kelanitissa in Sri Lanka due to higher offtaker demand as a result of lower hydrology and higher prices of $12 million at Kelanitissa due to higher pass-through fuel prices; and
- offset by outages of $6 million in Kelanitissa during the three months ended in September 30, 2011.

Excluding the favorable impact of foreign currency translation of $4 million, generation gross margin for the three months ended September 30, 2011 decreased $18 million, or 35%, compared to the three months ended September 30, 2010 primarily due to:

- a net decrease of $8 million at Masinloc attributable to lower spot prices offset in part by higher contract volume;
- a negative impact on gross margin of approximately $4 million at Kelanitissa due primarily to the planned plant outage.

For the three months ended September 30, 2011, revenue increased 26%, while gross margin decreased by 27%. This was primarily due to the negative influence on gross margin arising from lower rates at Masinloc and the outage at Kelanitissa.

Excluding the favorable impact of foreign currency translation of $20 million, generation revenue for the nine months ended September 30, 2011 decreased $62 million, or 13%, compared to the nine months ended September 30, 2010 primarily due to:

- a decrease of $55 million at Masinloc in the Philippines primarily due to lower generation prices and volume. Spot volume and prices were lower due to flat electricity demand and higher available capacity in the grid.

Excluding the favorable impact of foreign currency translation of $9 million, generation gross margin for the nine months ended September 30, 2011 decreased $70 million, or 36%, compared to the nine months ended September 30, 2010 primarily due to:

- a decrease of $64 million at Masinloc primarily attributable to lower generation prices and volume driven by a combination of flat market demand and lower spot prices, and higher coal prices.

For the nine months ended September 30, 2011, revenue decreased 9%, while gross margin decreased by 31%. This was primarily due to higher coal prices at Masinloc and pass-through revenue at Kelanitissa.

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, Wind Generation and other climate solutions and renewables projects which are immaterial for the purposes of separate segment disclosure. The following table excludes inter-segment activity and summarizes revenue and gross margin for Corporate and Other entities for the periods indicated:

	For the Three Months Ended September 30,			For the Nine Months Ended September 30,		
	2011	2010	% Change	2011	2010	% Change
	($ s in millions)			($ s in millions)		
Revenue						
Europe Utilities	$ 93	$ 90	3%	$ 293	$ 258	14%
Africa Utilities	61	91	-33%	271	279	-3%
Africa Generation	23	22	5%	67	66	2%
Wind Generation	42	44	-5%	172	139	24%
Corp/Other	5	11	-55%	21	22	-5%
Eliminations	(9)	(6)	-50%	(24)	(20)	-20%
Total Corporate and Other	$ 215	$ 252	-15%	$ 800	$ 744	8%
Gross Margin						
Europe Utilities	$ 5	$ 6	-17%	$ 15	$ 14	7%
Africa Utilities	(49)	7	-800%	(47)	10	-570%
Africa Generation	11	12	-8%	36	35	3%
Wind Generation	1	-	100%	49	20	145%
Corp/Other	(5)	5	-200%	(19)	1	-2000%
Eliminations	-	3	-100%	3	5	-40%
Total Corporate and Other	$ (37)	$ 33	-212%	$ 37	$ 85	-56%

Excluding the favorable impact of foreign currency translation of $7 million, revenue for the three months ended September 30, 2011 decreased $44 million, or 17%, compared to the three months ended September 30, 2010 primarily due to:

- a decrease of $38 million at Sonel, in Cameroon, from the unfavorable impact of an unrealized mark-to-market derivative adjustment, partially offset by higher tariff and volume.

Excluding the unfavorable impact of foreign currency translation of $2 million, gross margin for the three months ended September 30, 2011 decreased $68 million, or 206%, compared to the three months ended September 30, 2010 primarily due to:

- a decrease of $55 million at Sonel from the unfavorable impact of an unrealized mark-to-market derivative adjustment, the recognition of service disruption penalties and increased fixed costs, partially offset by higher tariff and volume.

For the three months ended September 30, 2011, revenue decreased 15%, while gross margin decreased by 212%. This was primarily due to the recognition of service disruption penalties at Sonel.

Excluding the favorable impact of foreign currency translation of $17 million, revenue for the nine months ended September 30, 2011 increased $39 million, or 5%, compared to the nine months ended September 30, 2010 primarily due to:

- higher tariff, partially offset by lower volume, of $35 million at our utility businesses in the Ukraine; and

Table of Contents

the additional revenue of $15 million from a wind generation project in Bulgaria that commenced operations in March 2010.

These increases were partially offset by:

a decrease of $25 million at Sonel from the unfavorable impact of an unrealized mark-to-market derivative adjustment, partially offset by higher tariff and volume.

Excluding the unfavorable impact of foreign currency translation of $4 million, gross margin for the nine months ended September 30, 2011 decreased $44 million, or 52%, compared to the nine months ended September 30, 2010 primarily due to:

a decrease of $53 million at Sonel from the unfavorable impact of an unrealized mark-to-market derivative adjustment, the recognition of service disruption penalties and increased fixed costs, partially offset by higher tariff and volume.

This decrease was partially offset by:

gross margin of $12 million from a wind generation project in Bulgaria that commenced operations in March 2010.

For the nine months ended September 30, 2011, revenue increased 8%, while gross margin decreased by 56%. This was primarily due to higher tariffs at our utility businesses in Ukraine, which only had a marginal impact on gross margin, and higher fixed costs and the recognition of service disruption penalties at Sonel.

General and Administrative Expense

General and administrative expense decreased $7 million, or 7%, to $91 million for the three months ended September 30, 2011. The decrease was primarily due to a reduction of SAP implementation costs and business development costs, partially offset by DPL transaction costs.

General and administrative expense increased $4 million, or 1%, to $283 million for the nine months ended September 30, 2011. The increase was primarily due to DPL transaction costs, partially offset by a reduction of SAP implementation and business development costs.

Interest expense

Interest expense increased $51 million, or 13%, to $432 million for the three months ended September 30, 2011. The increase was primarily due to increased average outstanding indebtedness at the Parent Company and less interest capitalization at Maritza due to the commencement of power plant operations.

Interest expense increased $27 million, or 2%, to $1.2 billion for the nine months ended September 30, 2011. The increase was primarily due to higher interest rates offset by lower average outstanding indebtedness, an unfavorable impact of foreign currency translation in Brazil, a monetary correction related to VAT over commercial losses at Eletropaulo, and additional bridge loan fees at the Parent Company.

Interest income

Interest income increased $7 million, or 7%, to $103 million for the three months ended September 30, 2011. The increase is primarily due to favorable foreign currency translation.

Interest income decreased $11 million, or 4%, to $293 million for the nine months ended September 30, 2011. The decrease was primarily due to the settlement of a dispute related to inflation adjustments for energy sales in Tiete in 2010 and a settlement of a loan receivable at a wind development project in Brazil in 2010. The decreases were partially offset by the favorable impact on foreign currency translation in Brazil.

Other expense

Other expense of $76 million for the three months ended September 30, 2011 was primarily due to the premium paid on the early retirement of debt at Gener, and losses on the disposal of assets at TermoAndes and Eletropaulo. Other expense of $23 million for the three months ended September 30, 2010 was primarily comprised of losses on disposal of assets at Eletropaulo and Gener.

Other expense of $131 million for the nine months ended September 30, 2011 was primarily due to the premium paid on early retirement of debt at Gener, a loss related to the early retirement of senior notes due in 2011 at IPL, and loss on disposal of assets at Eletropaulo and TermoAndes. Other expense of $83 million for the nine months ended September 30, 2010 included the previously capitalized transaction costs of $22 million that were incurred in connection with the preparation for the sale of a noncontrolling interest in our Wind Generation business. These costs were written off upon the expiration of the letter of intent (LOI) on June 30, 2010. Also, there was a $9 million loss on debt extinguishment at the Parent Company from the retirement of senior notes, and losses on disposal of assets at Eletropaulo and Gener.

Other income

Other income of $58 million for the three months ended September 30, 2011 was primarily due to an additional tax credit settlement from a favorable court decision in 2011 concerning reimbursement of excess non-income taxes paid from 1989 to 1992 at Eletropaulo, and the reimbursement of income tax expense recognized during the quarter related to an indemnity agreement between Los Mina and the Dominican Republic government. Other income of $17 million for the three months ended September 30, 2010 was primarily related to gain on sale of assets at Eletropaulo.

Other income of $108 million for the nine months ended September 30, 2011 was primarily related to the items described above, in addition to the gain on sale of mineral rights and land at IPL. Other income of $94 million for the nine months ended September 30, 2010 was primarily related to the extinguishment of a swap liability owed by two of our Brazilian subsidiaries, resulting in the recognition of a $62 million gain. The net impact to the Company after taxes and noncontrolling interest was $9 million. Other income also included a gain on sale of assets at Eletropaulo.

Goodwill impairment

Goodwill impairment was $17 million for the three and nine months ended September 30, 2011.

During the third quarter of 2011, the Company identified higher coal prices and the resulting reduced operating margins in China as a goodwill impairment indicator for Chigen, our holding company that holds AES interests in Chinese joint ventures. A significant downward revision of cash flow forecasts indicated that the fair value of Chigen reporting unit was lower than its carrying amount. See Note 15 *Other Non-operating Expense* to Item 1. Financial Statements for further information. As of September 30, 2011, Chigen had goodwill of $17 million. The Company performed an interim impairment evaluation of Chigen s goodwill and determined that goodwill had no implied fair value. As a result, the entire carrying amount of $17 million was recognized as goodwill impairment.

Goodwill impairment was $18 million for the three and nine months ended September 30, 2010.

During the third quarter of 2010, the Company determined there was an indicator that the carrying value of goodwill related to Deepwater, our pet coke-fired merchant generation facility in Texas, was not recoverable. This determination was based primarily on the fact that Deepwater did not operate for more than 30 days in the three months ended September 30, 2010, had incurred current operating and cash flow losses, and was forecasting operating and cash flow losses for the remainder of 2010 through 2014 as a result of decreases in future power price expectations and an increase in pet coke prices. Deepwater is reported in the North America Generation segment.

Asset impairment expense

Asset impairment expense was $163 million and $196 million for the three and nine months ended September 30, 2011, respectively.

During the third quarter of 2011, the Company evaluated the future use of certain wind turbines held in storage pending their installation. Due to reduced wind turbine market pricing and advances in turbine technology, the Company determined it was more likely than not that the turbines would be sold significantly before the end of their previously estimated useful lives. In addition, the Company has concluded that more likely than not non-refundable deposits it had made in prior years to a turbine manufacturer for the purchase of wind turbines are not recoverable. The Company determined it was more likely than not that it would not proceed with the purchase of turbines due to the availability of more advanced and lower cost turbines in the market. These developments were more likely than not as of September 30, 2011 and as a result were considered impairment indicators. In October 2011, the Company determined that an impairment had occurred as of September 30, 2011 as the aggregate carrying amount of $161 million of these assets was not recoverable and was reduced to their estimated fair value of $45 million determined under the market approach. This resulted in asset impairment expense of $116 million for the three and nine months ended September 30, 2011. Wind Generation is reported in the Corporate and Other segment.

During the third quarter of 2011, the markets for emission reduction offsets, including Certified Emission Reductions (CERs) and European Allowance Units (EUAs), experienced a significant adverse change, as the global economic conditions contributed to unforeseen deterioration in the market prices of CERs and EUAs. This decline in the market prices of emission reduction offsets adversely impacted the Company s Carbon Reduction Projects in Asia and Latin America. The Latin American project also incurred current period operating losses and is projecting continuing operating and cash flow losses for future periods. Consequently, we determined that indicators of impairment existed as of September 30, 2011 and the carrying amounts of these projects were not recoverable based on undiscounted cash flows. The fair value of the projects was then determined using discounted cash flow analysis. The aggregate carrying amount of $49 million of these projects was written down as their estimated fair value was $11 million, resulting in asset impairment expense of $33 million, which was limited to the carrying amounts of long-lived assets. Carbon Reduction Projects are reported in the Corporate and Other segment.

During the second quarter of 2011, the Company recognized asset impairment expense of $33 million for the long-lived assets of Kelanitissa, our diesel-fired generation plant in Sri Lanka. We have continued to evaluate the recoverability of our long-lived assets at Kelanitissa as a result of both the existing government regulation which may require the government to acquire an ownership interest and the current expectation of future losses. Our evaluation during the quarter indicated that the long-lived assets were no longer recoverable and accordingly they were written down to their estimated fair value of $33 million based on a discounted cash flow analysis. The long-lived assets had a carrying amount of $66 million prior to the recognition of asset impairment expense. An additional impairment of $4 million was recognized in the three months ended September 30, 2011. Kelanitissa is a Build-operate-transfer (BOT) generation facility and payments under its PPA are scheduled to decline over the PPA term. It is possible that further impairment charges may be required in the future as Kelanitissa gets closer to the BOT date. Kelanitissa is reported in the Asia Generation reportable segment.

Asset impairment expense was $296 million and $297 million for the three and nine months ended September 30, 2010, respectively.

Table of Contents

During the third quarter of 2010, the Company entered into annual negotiations with the offtaker of its Tisza II generation plant in Hungary. As a result of these preliminary negotiations, as well as the further deterioration of the economic environment in Hungary, the Company determined that an indicator of impairment existed at September 30, 2010. Thus, the Company performed an asset impairment test and determined that based on the undiscounted cash flow analysis, the carrying amount of the Tisza II asset group was not recoverable. The fair value of the asset group was then determined using a discounted cash flow analysis. The carrying value of the Tisza II asset group of $160 million exceeded the fair value of $75 million resulting in the recognition of asset impairment expense of $85 million during the three and nine months ended September 30, 2010. Tisza II is reported in the Europe Generation reportable segment.

In September 2010, the Office of Administrative Law in California approved the policy that would require the Company to change the process through which it uses ocean water to cool the generation turbines at its Alamitos, Huntington Beach and Redondo Beach (collectively Southland) gas-fired generation facilities in California. The policy requires compliance with the new regulations by December 31, 2020. The change in the water cooling process will result in significant future capital expenditures to ensure compliance with the new regulations or a shut down of the plants and, therefore, the Company determined that an indicator of impairment existed at September 30, 2010. The Company performed an asset impairment test and the asset group was determined to be at the individual plant level and based on the undiscounted cash flow analysis, the Company determined that the Huntington Beach asset group was not recoverable. The fair value of the Huntington Beach asset group was then determined using a discounted cash flow analysis. The carrying value of the Huntington Beach plant of $288 million exceeded the fair value of $88 million resulting in the recognition of asset impairment expense of $200 million for the three and nine months ended September 30, 2010. The undiscounted cash flows of the Alamitos and Redondo Beach asset groups exceeded their respective carrying values and resulted in no impairment. Huntington Beach is reported in the North America Generation reportable segment.

Gain on sale of investments

There was no gain on sale of investments for the three months ended September 30, 2011 and 2010.

Gain on sale of investments for the nine months ended September 30, 2011 was $7 million, primarily related to our sale of Wuhu, an equity investment in China that was accounted for under the equity method of accounting. There was no gain on sale of investments for the nine months ended September 30, 2010.

Foreign currency transaction gains (losses) on net monetary position

Foreign currency transaction gains (losses) were as follows:

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	(in millions)		(in millions)	
AES Corporation	$ (37)	$ 53	$ 10	$ (33)
Chile	(22)	27	(24)	7
Philippines	-	18	8	18
Brazil	(15)	5	(11)	(8)
Argentina	(1)	(2)	11	11
Colombia	3	(7)	(1)	(13)
Other	(20)	9	(14)	(1)
Total[(1)]	$ (92)	$ 103	$ (21)	$ (19)

(1) Includes $16 million in gains and $16 million in losses on foreign currency derivative contracts for the three months ended September 30, 2011 and 2010, respectively, and $35 million and $1 million in gains on foreign currency derivative contracts for the nine months ended September 30, 2011 and 2010, respectively.

Table of Contents

The Company recognized foreign currency transaction losses of $92 million for the three months ended September 30, 2011. These consisted primarily of losses at The AES Corporation, in Chile and in Brazil.

Losses of $37 million at The AES Corporation were primarily due to a decrease in the valuation of notes and trade receivables, primarily resulting from the weakening of the Euro and British Pound during the quarter.

Losses of $22 million in Chile were primarily due to an 11% devaluation of the Chilean Peso, resulting in losses at Gener (a U.S. Dollar functional currency subsidiary) associated with net working capital denominated in Chilean Pesos, primarily cash, accounts receivable and tax receivables as well as a $2 million loss on foreign currency derivatives.

Losses of $15 million in Brazil were primarily due to a 19% devaluation of the Brazilian Real, resulting in losses associated with U.S. Dollar denominated debt at the Company s subsidiaries in Brazil.

The Company recognized foreign currency transaction gains of $103 million for the three months ended September 30, 2010. These consisted primarily of gains at The AES Corporation, in Chile and in the Philippines.

Gains of $53 million at The AES Corporation were primarily due to the strengthening of the Euro and British Pound during the quarter, resulting in gains on notes receivables and cash balances denominated in Euros, which were partially offset by losses on debt denominated in British Pounds.

Gains of $27 million in Chile were primarily due to a 12% appreciation of the Chilean Peso resulting in gains at Gener associated with working capital denominated in Chilean Pesos, primarily cash, accounts receivable and tax receivables. These gains were partially offset by a $3 million loss on foreign currency derivatives.

Gains of $18 million in the Philippines were primarily due to appreciation of the Philippine Peso of 5% during the quarter, resulting in gains at Masinloc (a Philippine Peso functional currency subsidiary) on the remeasurement of U.S. Dollar denominated debt.

The Company recognized foreign currency transaction losses of $21 million for the nine months ended September 30, 2011. These consisted primarily of losses in Chile and Brazil, partially offset by gains in Argentina.

Losses of $24 million in Chile were primarily due to an 11% devaluation of the Chilean Peso, resulting in losses at Gener associated with net working capital denominated in Chilean Pesos, primarily cash, accounts receivable and tax receivables as well as an $8 million loss on foreign currency derivatives.

Losses of $11 million in Brazil were primarily due to a 11% devaluation of the Brazilian Real, resulting in losses associated with U.S. Dollar denominated debt at the Company s subsidiaries in Brazil.

Gains of $11 million in Argentina were primarily due to a gain on a foreign currency embedded derivative related to government receivables, partially offset by losses due to the devaluation of the Argentine Peso by 6%, resulting in losses at Alicura (an Argentine Peso functional currency subsidiary) associated with its U.S. Dollar denominated debt.

Table of Contents

The Company recognized foreign currency transaction losses of $19 million for the nine months ended September 30, 2010. These consisted primarily of losses at The AES Corporation and in Colombia, partially offset by gains in the Philippines and Argentina.

Losses of $33 million at The AES Corporation were primarily due to the weakening of the Euro during the nine months ended September 30, 2010, resulting in the devaluation of notes receivable and cash balances denominated in Euros.

Losses of $13 million in Colombia were primarily due to the appreciation of the Colombian Peso by 12%, resulting in losses at Chivor associated with its Colombian Peso denominated debt. In addition, there was a loss of $5 million from foreign currency derivatives.

Gains of $18 million in the Philippines were primarily due to appreciation of the Philippine Peso of 5% during the third quarter, resulting in gains at Masinloc on the remeasurement of U.S. Dollar denominated debt.

Gains of $11 million in Argentina were primarily due to a gain on a foreign currency embedded derivative related to government receivables, partially offset by losses due to the devaluation of the Argentine Peso by 4%, resulting in losses at Alicura with its U.S. Dollar denominated debt.

Other non-operating expense

Other non-operating expense of $82 million for the three and nine months ended September 30, 2011 primarily consisted of other-than-temporary impairments of equity method investments in China.

During the third quarter of 2011 as part of the quarterly close process, the Company evaluated YangCheng International Power Generating Co Ltd (YangCheng), a 2,100 MW coal-fired plant in China, for other-than-temporary-impairment. AES owns a 25% interest in YangCheng and the remaining equity interest in the venture is held by Chinese partners. During the nine months ended September 30, 2011, coal prices continued an upward trend in China, thereby, reducing the operating margin of coal generation facilities. During this time, there was no corresponding increase in tariffs to compensate for higher coal prices. Power prices in China are tightly regulated by the national and provincial governments, which often limit power generators ability to pass through increases in fuel costs to customers. In addition, under the YangCheng venture agreement, AES will surrender its equity interest to the JV partners in 2016 without additional compensation. During the nine months ended September 30, 2011, management continued to monitor the situation and in the third quarter determined that it was unlikely that there would be a reversal in the trends in coal prices during the remaining term of the venture. Accordingly, during September 2011, management revised downward its forecasts of earning and cash flows over the remaining term of the venture. The revised forecasts were significantly lower than management s earlier estimates such that the carrying amount of the investment in YangCheng was considered to have incurred an other-than-temporary-impairment. In determining the fair value of our investment, management used a discounted cash flow analysis based on probability-weighted revised cash distribution forecasts under multiple scenarios. As of September 30, 2011, YangCheng had a carrying amount of $100 million which was written down to the estimated fair value of $26 million, and the difference was recognized as other non-operating expense.

Other non-operating expense of $2 million and $7 million, respectively, for the three and nine months ended September 30, 2010 primarily consisted of an other-than-temporary impairment of an equity method investment.

Income tax expense

Income tax expense on continuing operations decreased $18 million, or 18%, to $84 million for the three months ended September 30, 2011 compared to $102 million for the three months ended September 30, 2010. The Company s effective tax rates were 37% and 28% for the three months ended September 30, 2011 and 2010, respectively.

Table of Contents

The net increase in the effective tax rate for the three months ended September 30, 2011 compared to the same period in 2010 was primarily due to a valuation allowance recorded at one of our Argentinean subsidiaries, the impact of the impairments recorded in the current period, and tax benefit related to a reversal of a Chilean withholding tax liability recorded in the third quarter of 2010. See Note 14 *Impairments* for additional information regarding the current period impairments. These items were offset by the extension of a favorable U.S. tax law in the fourth quarter of 2010 impacting distributions from certain non-U.S. subsidiaries and the impact of a depreciating Peso in certain of our Mexican subsidiaries.

Income tax expense on continuing operations decreased $71 million, or 13%, to $469 million for the nine months ended September 30, 2011 compared to $540 million for the nine months ended September 30, 2010. The Company s effective tax rates were 31% and 37% for the nine months ended September 30, 2011 and 2010, respectively.

The net decrease in the effective tax rate for the nine months ended September 30, 2011 compared to the same period in 2010 was primarily due to the extension of a favorable U.S. tax law in the fourth quarter of 2010 impacting distributions from certain non-U.S. subsidiaries and expense recorded in the second quarter of 2010 relating to the CEMIG sale transaction. These items were offset by a tax benefit related to a reversal of a Chilean withholding tax liability recorded in the third quarter of 2010. Included in the net 2010 tax expense relating to the CEMIG sale is tax expense on the equity earnings associated with the reversal of the net long-term liability and tax benefit upon the release of a valuation allowance against deferred tax assets.

Net equity in earnings of affiliates

Net equity in earnings of affiliates decreased $20 million, or 77%, to $6 million for the three months ended September 30, 2011. The decrease was primarily due to decreased earnings at Guacolda in Chile due to lower spot sales as well as foreign currency losses recognized at our affiliates in Turkey and our equity affiliate Cayman Energy Traders in Brazil.

Net equity in earnings of affiliates decreased $162 million, or 93%, to $12 million for the nine months ended September 30, 2011. The decrease was primarily due to the sale of our interest in CEMIG during the second quarter of 2010, higher coal prices at Yangcheng in China in 2011, and $30 million in impairments at AES Solar in 2011 of which our share was $15 million.

Income from continuing operations attributable to noncontrolling interests

Income from continuing operations attributable to noncontrolling interests increased $21 million, or 8%, to $269 million for the three months ended September 30, 2011. The increase was primarily due to increased volume at Eletropaulo driven by market demand as well as the appreciation of the Brazilian Real. These increases were partially offset by the devaluation of the Chilean Peso, losses on the extinguishment of debt at Gener and lower gross margin at Sonel due mainly to the unfavorable impact of an unrealized mark to market adjustment.

Income from continuing operations attributable to noncontrolling interests increased $41 million, or 6%, to $766 million for the nine months ended September 30, 2011. The increase was primarily due to the appreciation of the Brazilian Real and increased gross margin at Gener, partially offset by lower gross margin at Sonel due mainly to the unfavorable impact of an unrealized mark to market adjustment.

Discontinued operations

As further discussed in Note 16 *Discontinued Operations and Held for Sale Businesses,* discontinued operations include the results of the following businesses:

Brazil Telecom, 46% owned telecommunication businesses in Brazil (held for sale as of September 2011);

Eastern Energy, including Cayuga, Greenidge, Somerset and Westover, 100% owned coal-fired power plants in New York (held for sale since March 2011);

Borsod and Tiszapalkonya, 100% owned biomass and coal-fired facility and multi-fuel facility, respectively, in Hungary (held for sale since March 2011);

Ras Laffan, 55% owned combined cycle gas facility and water desalination plant in Qatar (sold in October 2010);

Barka, 35% owned combined cycle gas facility and water desalination plant in Oman (sold in August 2010); and

Lal Pir and Pak Gen, 55% owned oil-fired facilities in Pakistan (sold in June 2010).

Prior periods have been restated to reflect these businesses within Discontinued Operations for all periods presented.

For the three months and nine months ended September 30, 2011, operations of discontinued businesses, net of tax and income attributable to noncontrolling interests, incurred a net loss of $12 million and $29 million, respectively. Discontinued operations reflected the operations of Brazil Telecom, Eastern Energy, Borsod and Tiszapalkonya.

For the three months and nine months ended September 30, 2010, income from operations of discontinued businesses, net of tax and income attributable to noncontrolling interests, was $12 million and $42 million, respectively. Discontinued operations reflected the operations of all generation facilities mentioned above. During the three months ended September 30, 2010, the Barka plant was sold resulting in a gain on sale of $63 million, net of tax and income attributable to noncontrolling interests. During the nine months ended September 30, 2010, the Company recognized impairment and a loss on the sale of Lal Pir and Pak Gen of $14 million, net of tax and noncontrolling interests, consisting of $7 million impairment in the first quarter and $7 million loss on sale. Including the Barka sale, total impairments and gains on sales were $49 million for the nine months ended September 30, 2010, net of tax and noncontrolling interests.

Capital Resources and Liquidity

Overview

As of September 30, 2011, the Company had unrestricted cash and cash equivalents of $3.4 billion, of which approximately $2.1 billion was held at the Parent Company and qualified holding companies, and short term investments of $1.1 billion. In addition, we had restricted cash and debt service reserves of $1.7 billion. The Company also had non-recourse and recourse aggregate principal amounts of debt outstanding of $14.7 billion and $6.2 billion, respectively. Of the approximately $2.2 billion of our short-term non-recourse debt, $864 million was presented as current because it is due in the next twelve months and $1.3 billion relates to defaulted debt. We expect such current maturities will be repaid from net cash provided by operating activities of the subsidiary to which the debt relates or through opportunistic refinancing activity or some combination thereof. Approximately $11 million of our recourse debt matures within the next twelve months, which we expect to repay using cash on hand at the Parent Company or through net cash provided by operating activities. See further discussion of Parent Company Liquidity below.

During 2011, the Company issued $2.05 billion of recourse debt, which, among other things, may be used to partially finance the contemplated DPL acquisition, see Note 8 *Debt* and Note 17 *Acquisitions* in Notes to Condensed Consolidated Financial Statements in Item 1.

Table of Contents

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

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

Given our long-term debt obligations, the Company is subject to interest rate risk on debt balances that accrue interest at variable rates. When possible, the Company will borrow funds at fixed interest rates or hedge its variable rate debt to fix its interest costs on such obligations. In addition, the Company has historically tried to maintain at least 70% of its consolidated long-term obligations at fixed interest rates, including fixing the interest rate through the use of interest rate swaps. These efforts apply to the notional amount of the swaps compared to the amount of related underlying debt. Presently, the Parent Company s only material un-hedged exposure to variable interest rate debt relates to indebtedness under its senior secured credit facility. On a consolidated basis, of the Company s $14.7 billion of total non-recourse debt outstanding as of September 30, 2011, approximately $4.5 billion bore interest at variable rates that were not subject to a derivative instrument which fixed the interest rate.

In addition to utilizing non-recourse debt at a subsidiary level when available, the Parent Company provides a portion, or in certain instances all, of the remaining long-term financing or credit required to fund development, construction or acquisition of a particular project. These investments have generally taken the form of equity investments or intercompany loans, which are subordinated to the project s non-recourse loans. We generally obtain the funds for these investments from our cash flows from operations, proceeds from the sales of assets and/or the proceeds from our issuances of debt, common stock and other securities. Similarly, in certain of our businesses, the Parent Company may provide financial guarantees or other credit support for the benefit of counterparties who have entered into contracts for the purchase or sale of electricity, equipment or other services with our subsidiaries or lenders. In such circumstances, if a business defaults on its payment or supply obligation, the Parent Company will be responsible for the business obligations up to the amount provided for in the relevant guarantee or other credit support. At September 30, 2011, the Parent Company had provided outstanding financial and performance-related guarantees or other credit support commitments to or for the benefit of our businesses, which were limited by the terms of the agreements, of approximately $357 million in aggregate (excluding investment commitments and those collateralized by letters of credit and other obligations discussed below).

As a result of the Parent Company s below investment grade rating, counterparties may be unwilling to accept our general unsecured commitments to provide credit support. Accordingly, with respect to both new and existing commitments, the Parent Company may be required to provide some other form of assurance, such as a letter of credit, to backstop or replace our credit support. The Parent Company may not be able to provide adequate assurances to such counterparties. To the extent we are required and able to provide letters of credit or

Table of Contents

other collateral to such counterparties, this will reduce the amount of credit available to us to meet our other liquidity needs. At September 30, 2011, we had $12 million in letters of credit outstanding, provided under the senior secured credit facility, and $260 million in cash collateralized letters of credit outstanding outside of the senior secured credit facility. These letters of credit operate to guarantee performance relating to certain project development activities and business operations. During the quarter ended September 30, 2011, the Company paid letter of credit fees ranging from 0.25% to 3.25% per annum on the outstanding amounts.

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

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

As of September 30, 2011, the Company had approximately $365 million of trade accounts receivable related to certain of its generation and utility businesses in Latin America classified as other long-term assets. These consist primarily of trade accounts receivable that, pursuant to amended agreements or government resolutions, have collection periods that extend beyond September 30, 2012, or one year past the balance sheet date. The Company is actively collecting these receivables and believes such amounts are collectible based on collection history and performance under agreements. Additionally, the current portion of these trade accounts receivable was $36 million at September 30, 2011.

Consolidated Cash Flows. During the nine months ended September 30, 2011, cash and cash equivalents increased $842 million to $3.4 billion. The increase in cash and cash equivalents was due to $2.3 billion of cash provided by operating activities, $1.7 billion of cash used for investing activities, $347 million of cash provided by financing activities and the unfavorable effect of foreign currency exchange rates on cash of $79 million.

Operating Activities

Net cash provided by operating activities decreased $108 million to $2.3 billion during the nine months ended September 30, 2011 compared to $2.4 billion during the nine months ended September 30, 2010. This net decrease was primarily the result of the following:

- a decrease of $138 million at our Asia generation businesses primarily due to lower operating income and higher working capital requirements at Masinloc in the Philippines as well as from the sale of Lal Pir, Pak Gen, Barka and Ras Laffan in 2010;

- a decrease of $128 million at our North America generation businesses primarily due to reduced operations at our New York Plants and higher working capital requirements at Puerto Rico; offset by

- an increase of $83 million at our Latin American generation businesses primarily due to higher gross margin at our businesses in Chile and the Dominican Republic partially offset by lower margin in Panama and higher tax payments at Gener.

Table of Contents

Investing Activities

Net cash used for investing activities increased $387 million to $1.7 billion during the nine months ended September 30, 2011 compared to net cash used of $1.3 billion during the nine months ended September 30, 2010. This net increase was primarily due to the following:

- an increase of $370 million in debt service reserves and other assets during the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010. During the nine months ended September 30, 2011, $379 million of funds were transferred to debt service reserves and other assets primarily related to the collateralization for a letter of credit of $223 million at the Parent Company for the Mong Duong project, escrowed cash reserves of $115 million to cover certain expenses associated with the DPL acquisition financing at Dolphin II, lender imposed restrictions on funds of $25 million at Sonel and funds requested to pay a construction retainage at Panama of $24 million. These increases were partially offset by a transfer out of debt service reserves and other assets for payment of rent of $33 million at New York;

- a decrease of $322 million in proceeds from the sale of businesses for the nine months ended September 30, 2011. The decrease was primarily due to proceeds of $170 million related to the sale in August 2010 of Barka in Oman, the final settlement proceeds of $99 million received in January 2010 from the termination of a management agreement with Kazakhmys PLC in Kazakhstan related to Ekibastuz and Maikuben which were sold in May 2008 and the net proceeds from the sale of Lal Pir and Pak Gen in Pakistan in June 2010 of $100 million. These decreases were partially offset by an increase in proceeds of $36 million at Vietnam due to the sale of a 49% interest in Mong Duong;

- an increase of $304 million in capital expenditures to $1.8 billion primarily due to net increases in capital expenditures of $173 million at our Brazilian subsidiaries, $134 million at Vietnam, $80 million at Kribi and $71 million at Ipalco. These increases were partially offset by net decreases in capital expenditures of $96 million at Gener and $66 million at Maritza in Bulgaria;

- a decrease of $132 million in proceeds from loan repayments for the nine months ended September 30, 2011. In 2010, we received $132 million in proceeds related to the repayment of the loan receivable from a wind development project in Brazil; partially offset by

- an increase of $516 million to $559 million from the sale of short-term investments, net of purchases, for the nine months ended September 30, 2011 from $43 million from the sale of short-term investments, net of purchases for the nine months ended September 30, 2010. The increase was primarily due to increases in net sales of $437 million and $97 million at our Brazilian subsidiaries and Gener, respectively, due to the use of investment proceeds for dividend distributions. Net sales were partially offset by an increase in net purchases of $29 million at Chivor; and

- an increase of $199 million in proceeds related to a performance bond received at Maritza in Bulgaria to compensate for construction delays. There were no proceeds from performance bonds in 2010.

Financing Activities

Net cash provided by financing activities increased $325 million to $347 million during the nine months ended September 30, 2011 compared to $22 million during the nine months ended September 30, 2010. This net increase was primarily due to the following:

- a $2 billion increase in proceeds from the issuance of recourse debt at the Parent Company which is expected to be used to partially fund the acquisition of DPL;

a $145 million decrease in repayments of recourse debt due to higher repayments of maturing debt at the Parent Company in 2010; partially offset by a $1.6 billion decrease in the issuance of common stock, net of transaction costs due to the China Investment Corporation transaction in 2010;

a $210 million increase in the purchase of treasury stock under the company s common stock repurchase plan; and

a $103 million increase in payments for financing fees primarily due to the issuance of debt at the Parent Company, Vietnam and Gener.

Parent Company Liquidity

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

dividends and other distributions from our subsidiaries, including refinancing proceeds;

proceeds from debt and equity financings at the Parent Company level, including availability under our credit facilities; and

proceeds from asset sales.

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

interest;

principal repayments of debt;

acquisitions;

construction commitments;

other equity commitments;

equity repurchases;

taxes; and

Parent Company overhead and development costs.

Table of Contents

The Company defines Parent Company Liquidity as cash available to the Parent Company plus available borrowings under existing credit facilities. The cash held at qualified holding companies represents cash sent to subsidiaries of the Company domiciled outside of the U.S. Such subsidiaries have no contractual restrictions on their ability to send cash to the Parent Company. Parent Company Liquidity is reconciled to its most directly comparable U.S. GAAP financial measure, cash and cash equivalents at September 30, 2011 and December 31, 2010 as follows:

Parent Company Liquidity	**September 30, 2011**	**December 31, 2010**
	(in millions)	
Consolidated cash and cash equivalents	$ 3,392	$ 2,550
Less: Cash and cash equivalents at subsidiaries	(1,303)	(1,428)
Parent and qualified holding companies cash and cash equivalents	2,089	1,122
Commitments under Parent credit facilities	800	800
Less: Borrowings and letters of credit under the credit facilities	(12)	(85)
Borrowings available under Parent credit facilities	788	715
Total Parent Company Liquidity	$ 2,877	$ 1,837

The following table summarizes our Parent Company contingent contractual obligations as of September 30, 2011:

Contingent contractual obligations	**Amount (in millions)**	**Number of Agreements**	**Maximum Exposure Range for Each Agreement (in millions)**
Guarantees	$ 357	23	<$1 - $53
Letters of credit under the senior secured credit facility	12	11	<$1 - $7
Cash collateralized letters of credit	260	13	<$1 - $223
Total	$ 629	47	

As of September 30, 2011, the Company had $16 million of commitments to invest in subsidiaries under construction and to purchase related equipment that were not included in the letters of credit discussed above. The Company expects to fund these net investment commitments in 2011. The exact payment schedules will be dictated by the construction milestones. Additionally, subject to regulatory approvals, the Company is committed to purchase DPL for $3.5 billion, see Note 17 *Acquisitions* for further information. We expect to fund these commitments from a combination of current liquidity and internally generated Parent Company cash flow.

As of September 30, 2011, Parent Company Liquidity included the proceeds from the senior secured term loan and the 7.375% 2021 Notes, which may, among other things, be used to partially finance the Company s contemplated acquisition of DPL Inc., as discussed further in Note 17 *Acquisitions*.

We have a diverse portfolio of performance related contingent contractual obligations. These obligations are designed to cover potential risks and only require payment if certain targets are not met or certain contingencies occur. The risks associated with these obligations include change of control, construction cost overruns, subsidiary default, political risk, tax indemnities, spot market power prices, sponsor support and liquidated damages under power sales agreements for projects in development, in operation and under construction. While we do not expect that we will be required to fund any material amounts under these contingent contractual obligations during 2012 or beyond, many of the events which would give rise to such obligations are beyond our control. We can provide no assurance that we will be able to fund our obligations under these contingent contractual obligations if we are required to make substantial payments thereunder.

Table of Contents

While we believe that our sources of liquidity will be adequate to meet our needs for the foreseeable future, this belief is based on a number of material assumptions, including, without limitation, assumptions about our ability to access the capital markets (see *Key Trends and Uncertainties* and *Global Economic Conditions*), the operating and financial performance of our subsidiaries, currency exchange rates, power market pool prices, and the ability of our subsidiaries to pay dividends. In addition, our subsidiaries ability to declare and pay cash dividends to us (at the Parent Company level) is subject to certain limitations contained in loans, governmental provisions and other agreements. We can provide no assurance that these sources will be available when needed or that the actual cash requirements will not be greater than anticipated. We have met our interim needs for shorter-term and working capital financing at the Parent Company level with our senior secured credit facility. See Item 1A. Risk Factors, *The AES Corporation is a holding company and its ability to make payments on its outstanding indebtedness, including its public debt securities, is dependent upon the receipt of funds from its subsidiaries by way of dividends, fees, interest, loans or otherwise.* of the Company s 2010 Form 10-K.

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

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