RRI ENERGY INC
Form 10-Q
November 03, 2010

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549
FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2010

OR

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

For the transition period from __________ to __________

Commission file number 1-16455

RRI Energy, Inc.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**76-0655566**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1000 Main Street
Houston, Texas 77002
(Address of Principal Executive Offices) (Zip Code)
(832) 357-3000
(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 þ No o

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 þ No o

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 þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

As of October 26, 2010, the latest practicable date for determination, RRI Energy, Inc. had 353,439,183 shares of common stock outstanding and no shares of treasury stock.

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PART II.
OTHER INFORMATION

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SAFE HARBOR-FORWARD-LOOKING INFORMATION

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are statements that contain projections, assumptions or estimates about our revenues, income, capital structure and other financial items, our plans and objectives for future operations or about our future economic performance, possible transactions, dispositions, financings or offerings, and overview of economic and market conditions. In many cases, you can identify forward-looking statements by terminology such as anticipate, estimate, believe, think, continue, could, intend, may, plan, potential, predict, should, will, expect, objective, projection, foreca outlook, effort, target and other similar words. However, the absence of these words does not mean that the statements are not forward-looking.

Actual results may differ materially from those expressed or implied by the forward-looking statements as a result of many factors or events, including, but not limited to, the following:

- Demand and market prices for electricity, capacity, fuel and emission allowances
- The timing and extent of changes in commodity prices
- Limitations on our ability to set rates at market prices
- Legislative, regulatory and/or market developments
- Changes in environmental regulations that constrain our operations or increase our compliance costs
- Competition in the wholesale power markets
- Operating without long-term power sales agreements
- Ineffective hedging activities
- Our ability to obtain adequate fuel supply and/or transmission services
- Interruption or breakdown of our plants
- Failure of third parties to perform contractual obligations
- Failure to meet our debt service obligations or restrictive covenants
- Changes in the wholesale power market or in our evaluation of our plants
- The outcome of pending or threatened lawsuits, regulatory proceedings, tax proceedings and investigations
- Weather-related events or other events beyond our control
- Financial and economic market conditions and our access to capital and
- The successful and timely completion of the proposed merger with Mirant Corporation and related refinancing, which could be materially and adversely affected by, among other things, the following:
  - resolving any litigation brought in connection with the proposed merger
  - the timing and terms and conditions of required governmental and regulatory approvals
  - the ability to maintain relationships with employees, suppliers or customers as well as the ability to integrate the businesses and realize cost savings

Other factors that could cause our actual results to differ from our projected results are discussed or referred to in the Risk Factors sections of this report and of our most recent Annual Report on Form 10-K filed with the Securities and Exchange Commission. Each forward-looking statement speaks only as of the date of the particular statement and we undertake no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. Our filings and other important information are also available on our investor page at www.rrienergy.com.

PART I.
FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

RRI ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(thousands of dollars, except per share amounts)			
Revenues:				
Revenues (including $49,536, $(25,095), $98,621 and $(51,225) unrealized gains (losses))	$ 697,556	$ 507,179	$ 1,702,464	$ 1,363,140
Expenses:				
Cost of sales (including $856, $31,826, $13,278 and $20,857 unrealized gains)	305,616	267,632	837,415	872,373
Operation and maintenance	116,196	114,457	459,815	428,567
General and administrative	20,215	23,686	76,403	80,345
Western states litigation and similar settlements			17,000	
Gains on sales of assets and emission and exchange allowances, net	(664)	(1,013)	(1,700)	(21,184)
Long-lived assets impairments	112,856		360,571	
Depreciation and amortization	64,968	67,724	196,436	203,228
Total operating expense	619,187	472,486	1,945,940	1,563,329
Operating Income (Loss)	78,369	34,693	(243,476)	(200,189)
Other Income (Expense):				
Debt extinguishments gains (losses)		(103)		741
Interest expense	(39,568)	(44,614)	(122,197)	(136,600)
Interest income	126	407	492	1,376
Other, net	2,040	880	4,663	942
Total other expense	(37,402)	(43,430)	(117,042)	(133,541)
Income (Loss) from Continuing Operations Before Income Taxes	40,967	(8,737)	(360,518)	(333,730)
Income tax expense (benefit)	18,805	9,532	69,657	(105,988)
Income (Loss) from Continuing Operations	22,162	(18,269)	(430,175)	(227,742)
Income from discontinued operations	664	2,841	4,178	864,467
Net Income (Loss)	$ 22,826	$ (15,428)	$ (425,997)	$ 636,725

Basic and Diluted Earnings (Loss) per Share:								
Income (loss) from continuing operations	$	0.06	$	(0.05)	$	(1.22)	$	(0.65)
Income from discontinued operations				0.01		0.01		2.46
Net income (loss)	$	0.06	$	(0.04)	$	(1.21)	$	1.81

See Notes to our Unaudited Consolidated Interim Financial Statements

RRI ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	September 30, 2010	December 31, 2009
	(thousands of dollars, except per share amounts)	
	(unaudited)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 781,097	$ 943,440
Restricted cash	6,930	24,093
Accounts and notes receivable, principally customer, net	124,054	152,569
Inventory	280,612	331,584
Derivative assets	175,146	132,062
Margin deposits	124,953	198,582
Prepayments and other current assets	86,404	86,844
Current assets of discontinued operations ($14,823 and $55,855 of margin deposits)	40,641	108,476
Total current assets	1,619,837	1,977,650
Property, plant and equipment, gross	5,766,852	6,330,879
Accumulated depreciation	(1,644,285)	(1,728,566)
Property, Plant and Equipment, net	4,122,567	4,602,313
Other Assets:		
Other intangibles, net	290,977	305,913
Derivative assets	51,488	53,138
Prepaid lease	285,772	277,370
Other ($27,655 and $33,793 accounted for at fair value)	198,165	239,078
Long-term assets of discontinued operations	3,230	5,232
Total other assets	829,632	880,731
Total Assets	$ 6,572,036	$ 7,460,694
LIABILITIES AND EQUITY		
Current Liabilities:		
Current portion of long-term debt	$ 108	$ 404,505
Accounts payable, principally trade	99,346	142,787
Derivative liabilities	88,714	151,461
Margin deposits	33,479	2,860
Other	233,318	169,898
Current liabilities of discontinued operations ($0 and $11,000 of margin deposits)	14,891	58,452

Total current liabilities		469,856		929,963
Other Liabilities:				
Derivative liabilities		35,964		61,436
Other		265,069		260,547
Long-term liabilities of discontinued operations		13,315		13,700
Total other liabilities		314,348		335,683
Long-term Debt		1,949,689		1,949,771
Commitments and Contingencies				
Temporary Equity Stock-based Compensation		7,303		6,890
Stockholders Equity:				
Preferred stock; par value $0.001 per share (125,000,000 shares authorized; none outstanding)				
Common stock; par value $0.001 per share (2,000,000,000 shares authorized; 353,432,149 and 352,785,985 issued)		114		114
Additional paid-in capital		6,268,528		6,259,248
Accumulated deficit		(2,398,386)		(1,972,389)
Accumulated other comprehensive loss		(39,416)		(48,586)
Total stockholders equity		3,830,840		4,238,387
Total Liabilities and Equity	$	6,572,036	$	7,460,694

See Notes to our Unaudited Consolidated Interim Financial Statements

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RRI ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2010	**2009**
	(thousands of dollars)	
Cash Flows from Operating Activities:		
Net income (loss)	$ (425,997)	$ 636,725
Income from discontinued operations	(4,178)	(864,467)
Loss from continuing operations	(430,175)	(227,742)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	196,436	203,228
Deferred income taxes	67,566	(106,923)
Net changes in energy derivatives	(107,469)	30,748
Gains on sales of assets and emission and exchange allowances, net	(1,700)	(21,184)
Western states litigation and similar settlements	17,000	
Long-lived assets impairments	360,571	
Amortization of deferred financing costs	5,220	5,405
Other, net	(7,426)	(1,392)
Changes in other assets and liabilities:		
Accounts and notes receivable, net	29,411	117,255
Inventory	48,189	(1,399)
Margin deposits, net	104,248	(239,903)
Net derivative assets and liabilities	(2,358)	(26,816)
Western states litigation and similar settlement payments		(3,449)
Accounts payable	(23,814)	(9,111)
Other current assets	361	7,817
Other assets	(17,165)	(19,858)
Taxes payable/receivable	773	(3,479)
Other current liabilities	23,726	36,779
Other liabilities	(10,911)	(15,719)
Net cash provided by (used in) continuing operations from operating activities	252,483	(275,743)
Net cash provided by discontinued operations from operating activities	34,586	534,275
Net cash provided by operating activities	287,069	258,532
Cash Flows from Investing Activities:		
Capital expenditures	(64,041)	(157,750)
Proceeds from sales of assets, net	8,385	35,931
Proceeds from sales of emission and exchange allowances	139	19,180
Purchases of emission allowances	(270)	(7,624)
Other, net	4,863	2,998

Net cash used in continuing operations from investing activities		(50,924)		(107,265)
Net cash provided by (used in) discontinued operations from investing activities		(4,402)		313,775
Net cash provided by (used in) investing activities		(55,326)		206,510
Cash Flows from Financing Activities:				
Payments of long-term debt		(399,809)		(59,413)
Proceeds from issuances of stock		1,899		4,584
Net cash used in continuing operations from financing activities		(397,910)		(54,829)
Net cash used in discontinued operations from financing activities				(260,707)
Net cash used in financing activities		(397,910)		(315,536)
Net Change in Cash and Cash Equivalents, Total Operations		(166,167)		149,506
Less: Net Change in Cash and Cash Equivalents, Discontinued Operations		(3,824)		(100,197)
Cash and Cash Equivalents at Beginning of Period, Continuing Operations		943,440		1,004,367
Cash and Cash Equivalents at End of Period, Continuing Operations	$	781,097	$	1,254,070
Supplemental Disclosure of Cash Flow Information:				
Cash Payments:				
Interest paid (net of amounts capitalized) for continuing operations	$	93,071	$	89,127
Income taxes paid (net of income tax refunds received) for continuing operations		1,167		4,582

See Notes to our Unaudited Consolidated Interim Financial Statements

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RRI ENERGY, INC. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED INTERIM FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

(a) Background.

RRI Energy refers to RRI Energy, Inc. and we, us and our refer to RRI Energy, Inc. and its consolidated subsidiaries. We provide energy, capacity, ancillary and other energy services to wholesale customers in competitive energy markets in the United States through our ownership and operation of and contracting for power generation capacity. Our business consists of four reportable segments. See note 17. Our consolidated interim financial statements and notes (interim financial statements) are unaudited, omit certain disclosures and should be read in conjunction with our audited consolidated financial statements and notes in our Form 10-K.

See note 2 for discussion of our proposed merger with Mirant Corporation (Mirant).

(b) Basis of Presentation.

Estimates. Management makes estimates and assumptions to prepare financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) that affect:

- the reported amounts of assets, liabilities and equity
- the reported amounts of revenues and expenses
- our disclosure of contingent assets and liabilities at the date of the financial statements

Actual results could differ from those estimates.

We evaluate our estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic environment, which we think to be reasonable under the circumstances. We adjust such estimates and assumptions when facts and circumstances dictate.

Adjustments and Reclassifications. The interim financial statements reflect all normal recurring adjustments necessary, in management s opinion, to present fairly our financial position and results of operations for the reported periods. Amounts reported for interim periods, however, may not be indicative of a full year period because of seasonal fluctuations in demand for electricity and energy services, changes in commodity prices, and changes in regulations, timing of maintenance and other expenditures, dispositions, changes in interest expense and other factors.

Inventory. We value fuel inventories at the lower of average cost or market. We reduce these inventories as they are used in the production of electricity or sold. We recorded $1 million and $23 million during the three months ended September 30, 2010 and 2009, respectively, for lower of average cost or market valuation adjustments in cost of sales and recorded $4 million and $82 million during the nine months ended September 30, 2010 and 2009, respectively.

New Accounting Pronouncement Improving Disclosures about Fair Value Measurements. Effective for the first quarter of 2010, this guidance requires disclosures of significant transfers in and out of Levels 1 and 2. In addition, it clarifies existing disclosure requirements regarding inputs and valuation techniques as well as the appropriate level of disaggregation for fair value measurements disclosures. See note 4. Effective for the first quarter of 2011 financial statements, this guidance requires separate presentation of purchases, sales, issuances and settlements within the Level 3 reconciliation.

(2) Proposed Merger with Mirant

On April 11, 2010, we entered into an Agreement and Plan of Merger with Mirant. We have formed a new wholly-owned subsidiary that will merge with and into Mirant upon closing. As a result, Mirant will be a wholly-owned subsidiary of RRI Energy. We anticipate completing the merger before the end of 2010.

Upon closing the merger, each issued and outstanding share of Mirant common stock, including shares in reserve under the Chapter 11 plan of reorganization for Mirant, will convert into the right to receive 2.835 shares of common stock of RRI Energy, including the preferred share purchase rights granted under the Rights Agreement dated January 15, 2001, between RRI Energy and The Chase Manhattan Bank as Rights Agent. Mirant stock options and other equity awards will convert upon completion of the merger into vested stock options and equity awards with respect to RRI Energy common stock, after giving effect to the exchange ratio. The exchange ratio is fixed but subject to adjustment for a proposed reverse stock split.

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Completion of the merger is subject to each of RRI Energy and Mirant receiving legal opinions that the merger will qualify as a tax-free reorganization under the Internal Revenue Code of 1986, as amended. Under a tax-free reorganization, none of RRI Energy, Mirant or any of the Mirant stockholders generally will recognize any gain or loss in the transaction, except that Mirant stockholders will recognize gain with respect to cash received in lieu of fractional shares of RRI Energy common stock.

The primary remaining condition to closing the merger is completion by the Department of Justice (DOJ) of its review of the merger. On June 14, 2010, we and Mirant filed notification of the proposed transaction with the Federal Trade Commission and the DOJ under the Hart-Scott-Rodino Antitrust Improvements Act (the HSR Act). On July 15, 2010, we received a request for additional information from the DOJ. The additional information is to assist the DOJ on its review of the merger.

On September 20, 2010, both companies entered into agreements which provide for the companies to borrow $1.925 billion upon the closing of the proposed merger. In addition, the companies entered into a revolving credit facility. Completion of these financings is subject to the satisfaction of customary conditions. Upon closing of the merger, the proceeds of these financings and cash on hand will be used to (a) discharge the RRI Energy senior notes due 2014 and the Mirant North America (MNA) senior unsecured notes due 2013, (b) defease the RRI Energy Pennsylvania Economic Development Financing Authority (PEDFA) 6.75% bonds due 2036, (c) repay the MNA senior secured term loan maturing in 2013 and (d) pay related fees and expenses, including accrued interest. Upon their completion, these financings will satisfy the financing condition in the merger agreement.

(3) Stock-based Compensation

Our compensation expense for our stock-based incentive plans was:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in millions)			
Stock-based incentive plans compensation expense (pre-tax) (1)	$ 2(2)	$ 3	$ 9(2)	$ 7

(1) See note 10 to our consolidated financial statements in our Form 10-K for information about our stock-based incentive plans compensation expense/income.

(2) During the three and nine months ended September 30, 2010, we recorded an

insignificant amount and $2 million, respectively, of expense related to the modification of our outstanding time-based stock options in contemplation of the merger. See note 2 for discussion of the merger.

During March 2010, the compensation committee of our board of directors granted (a) 917,746 time-based restricted stock options (exercise price of $4.28 per share which vest in three equal installments during March 2011, 2012 and 2013), (b) 462,500 time-based restricted stock options (exercise price of $4.20 per share which vest in three equal installments during March 2011, 2012 and 2013), (c) 909,423 time-based restricted stock units (which vest during March 2013), (d) 317,890 time-based cash units (which vest during March 2013) and (e) 690,123 performance-based cash units (which vest during March 2013) to employees under our stock and incentive plans. The performance-based cash units, which are liability-classified awards, are each payable into a cash amount equal to the market value of one share of our common stock based on the three-year average total shareholder return for the period beginning March 3, 2010 and ending March 3, 2013 compared to the relative three-year average total shareholder return for the same period of a group of our peer companies. The Monte Carlo simulation valuation model is used, on each reporting measurement date, to estimate the fair value of these performance-based cash awards.

No tax benefits related to stock-based compensation were realized during the three and nine months ended September 30, 2010 and 2009 because of our net operating loss carryforwards.

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(4) Fair Value Measurements

Fair Value Hierarchy and Valuation Techniques. We apply recurring fair value measurements to our financial assets and liabilities. In determining fair value, we generally use a market approach and incorporate assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and/or the risks inherent in the inputs to the valuation techniques. These inputs can be readily observable, market corroborated, or generally unobservable internally developed inputs. Based on the observability of the inputs used in our valuation techniques, our financial assets and liabilities are classified as follows:

Level 1: Level 1 represents unadjusted quoted market prices in active markets for identical assets or liabilities that are accessible at the measurement date. This category primarily includes our energy derivative instruments that are exchange-traded or that are cleared and settled through the exchange. Our cash equivalents and available-for-sale and trading securities are also valued using Level 1 inputs.

Level 2: Level 2 represents quoted market prices for similar assets or liabilities in active markets, quoted market prices in markets that are not active or other inputs that are observable or can be corroborated by observable market data. This category includes emission allowances futures that are exchange-traded and over-the-counter (OTC) derivative instruments such as generic swaps, forwards and options.

Level 3: This category includes our energy derivative instruments whose fair value is estimated based on internally developed models and methodologies utilizing significant inputs that are generally less readily observable from objective sources (such as implied volatilities and correlations). Our OTC, complex or structured derivative instruments that are transacted in less liquid markets with limited pricing information are included in Level 3. Examples are coal contracts, longer term natural gas contracts and options valued using implied or internally developed inputs.

The fair value measurements of these derivative assets and liabilities are based largely on unadjusted indicative quoted prices from independent brokers in active markets who regularly facilitate our transactions. An active market is considered to have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. Derivative instruments for which fair value is calculated using quoted prices that are deemed not active or that have been extrapolated from quoted prices in active markets are classified as Level 3. For certain natural gas and power contracts, we adjust seasonal or calendar year quoted prices based on historical observations to represent fair value for each month in the season or calendar year, such that the average of all months is equal to the quoted price. A derivative instrument that has a tenor that does not span the quoted period is considered an unobservable Level 3 measurement.

We evaluate and validate the inputs we use to estimate fair value by a number of methods, including validating against market published prices and daily broker quotes obtainable from multiple pricing services. For OTC derivative instruments classified as Level 2, indicative quotes obtained from brokers in liquid markets generally represent fair value of these instruments. We think these price quotes are executable. Adjustments to the quotes are adjustments to the bid or ask price depending on the nature of the position to appropriately reflect exit pricing and are considered a Level 3 input to the fair value measurement. In less liquid markets such as coal, in which a single broker s view of the market is used to estimate fair value, we consider such inputs to be unobservable Level 3 inputs. We do not use third party sources that determine price based on market surveys or proprietary models.

We value some of our OTC, complex or structured derivative instruments using a variety of valuation models, which utilize inputs that may not be corroborated by market data and vary in complexity depending on the contractual terms of, and inherent risks in, the instrument being valued. We use both industry-standard models as well as internally developed proprietary valuation models that consider various assumptions, such as market prices for power and fuel, price shapes, volatilities and correlations as well as other relevant factors. When such inputs are significant to the fair value measurement, the derivative assets or liabilities are classified as Level 3 when we do not have corroborating market evidence to support significant valuation model inputs and cannot verify the model to market transactions. We think the transaction price is the best estimate of fair value at inception under the exit price methodology.

Accordingly, when a pricing model is used to value such an instrument, the resulting value is adjusted so the model value at inception equals the transaction price. Valuation models are typically impacted by Level 1 or Level 2 inputs that can be observed in the market, as well as unobservable Level 3 inputs. Subsequent to initial recognition, we update Level 1 and Level 2 inputs to reflect observable market changes. Level 3 inputs are updated when corroborated by available market evidence. In the absence of such evidence, management s best estimate is used.

See note 7 for discussion of our fair value measurements for some non-financial assets.

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Fair Value of Derivative Instruments and Certain Other Assets. We apply recurring fair value measurements to our financial assets and liabilities. Fair value measurements of our financial assets and liabilities by class are as follows:

	September 30, 2010									
		Level 1(1)		Level 2(1)		Level 3 (in millions)		Reclassifications(2)		Total Fair Value
Derivative assets:										
Power	$	73	$	42	$	6	$		$	121
Power basis				1		7				8
Capacity energy						4				4
Natural gas		71								71
Natural gas basis		6								6
Coal						15				15
Other								1		1
Total derivative assets	$	150	$	43	$	32	$	1	$	226
Derivative liabilities:										
Power	$	18	$	83	$	4	$		$	105
Power basis				7						7
Natural gas		1				1				2
Natural gas basis		4								4
Coal						3				3
Emissions				2						2
Other								1		1
Total derivative liabilities	$	23	$	92	$	8	$	1	$	124
Cash equivalents(3)	$	781	$		$		$		$	781
Other assets(4)	$	28	$		$		$		$	28

(1) Transfers between Level 1 and Level 2 are recognized as of the beginning of the reporting period. There were no significant transfers during the nine months ended September 30, 2010.

(2) Reclassifications are required to reconcile to our consolidated balance sheet presentation.

(3) Represent investments in money market funds and are included in cash and cash equivalents in our consolidated balance sheet.

(4) Include $10 million in available-for-sale securities (shares in a public exchange) and $18 million in trading securities (rabbi trust investments (which are comprised of mutual funds) associated with our non-qualified deferred compensation plans for key and highly compensated employees).

	December 31, 2009				
	Level 1	Level 2	Level 3	Reclassifications(1)	Total Fair Value
			(in millions)		
Total derivative assets	$ 137	$ 46	$ 4	$ (2)	$ 185
Total derivative liabilities	49	134	32	(2)	213
Cash equivalents(2)	965				965
Other assets(3)	34				34

(1) Reclassifications are required to reconcile to our consolidated balance sheet presentation.

(2) Represent investments in money market funds and are included in cash and cash equivalents and restricted cash in our consolidated balance sheet. We had $943 million of cash equivalents included in cash and cash equivalents and $22 million of cash equivalents included in restricted cash.

(3) Include $13 million in available-for-sale securities (shares in a public exchange) and $21 million in trading securities (rabbi trust investments (which are comprised of mutual funds) associated with our non-qualified deferred compensation plans for key and highly compensated employees).

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The following is a reconciliation of changes in fair value of net commodity derivative assets and liabilities classified as Level 3:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	Net Derivatives (Level 3)		Net Derivatives (Level 3)	
	(in millions)			
Balance, beginning of period (net asset (liability))	$ 10	$ (117)	$ (28)	$ (114)
Total gains (losses) realized/unrealized included in earnings[1]	19	(7)	59	(78)
Purchases, issuances and settlements (net)	(5)	47	(7)	115
Transfers into Level 3[2]				
Transfers out of Level 3[2]				
Balance, end of period (net asset (liability))	$ 24	$ (77)	$ 24	$ (77)
Changes in unrealized gains (losses) relating to derivative assets and liabilities still held as of September 30, 2010 and 2009:				
Revenues	$ 7	$	$ 11	$ (1)
Cost of sales	8	(6)	21	(41)
Total	$ 15	$ (6)	$ 32	$ (42)

(1) Recorded in revenues and cost of sales.

(2) Recognized as of the beginning of the reporting period.

Nonperformance Risk. Derivative assets are discounted for credit risk using a yield curve representative of the counterparty s probability of default. The counterparty s default probability is based on a modified version of published default rates, taking 20-year historical default rates from Standard & Poor s and Moody s and adjusting them to reflect a rolling five-year average. Fair value measurement of our derivative liabilities reflects the nonperformance risk related to that liability, which is our own credit risk. We derive our nonperformance risk by applying our credit default swap spread against the respective derivative liability.

Fair Value of Other Financial Instruments. The fair values of cash, accounts receivable and payable and margin deposits approximate their carrying amounts. Values of our debt for continuing operations (see note 9) are:

	September 30, 2010		December 31, 2009	
	Carrying Value	Fair Value[1]	Carrying Value	Fair Value[1]

				(in millions)				
Fixed rate debt	$	1,950	$	1,912	$	2,355	$	2,333
Total debt	$	1,950	$	1,912	$	2,355	$	2,333

(1) We based the fair values of our fixed rate debt on market prices and quotes from an investment bank.

See note 5.

(5) Derivative Instruments and Hedging Activities

Changes in commodity prices prior to the energy delivery period are inherent in our business. Accordingly, we may enter selective hedges, including originated transactions, to (a) seek potential value greater than what is available in the spot or day-ahead markets, (b) address operational requirements or (c) seek a specific financial objective. For our risk management activities, we use derivative and non-derivative contracts that provide for settlement in cash or by delivery of a commodity. We use derivative instruments such as futures, forwards, swaps and options to execute our hedge strategy. We may also enter into derivatives to manage our exposure to changes in prices of emission and exchange allowances.

We account for our derivatives under one of three accounting methods (mark-to-market, accrual (under the normal purchase/normal sale exception to fair value accounting) or cash flow hedge accounting) based on facts and circumstances. See note 4 for discussion on fair value measurements.

A derivative is recognized at fair value in the balance sheet whether or not it is designated as an accounting hedge, except for derivative contracts designated as normal purchase/normal sale exceptions, which are not in our consolidated balance sheet or results of operations prior to settlement resulting in accrual accounting treatment.

Realized gains and losses on derivative contracts used for risk management purposes and not held for trading purposes are reported either on a net or gross basis based on the relevant facts and circumstances. Hedging transactions that do not physically flow are included in the same caption as the items being hedged.

A summary of our derivative activities and classification in our results of operations is:

Instrument	Primary Risk Exposure	Purpose for Holding or Issuing Instrument(1)	Transactions that Physically Flow/Settle(2)	Transactions that Financially Settle(3)
Power futures, forward, swap and option contracts	Price risk	Power sales to customers	Revenues	Revenues
		Power purchases related to operations	Cost of sales	Revenues
		Power purchases/sales related to legacy trading and non-core asset management positions(4)	Revenues	Revenues
Natural gas and fuel futures, forward, swap and option contracts	Price risk	Natural gas and fuel sales related to operations	Revenues/Cost of sales	Cost of sales
		Natural gas sales related to power generation(5)	N/A(6)	Revenues
		Natural gas and fuel purchases related to operations	Cost of sales	Cost of sales
		Natural gas and fuel purchases/sales related to legacy trading and non-core asset management positions(4)	Cost of sales	Cost of sales
Emission and exchange allowances futures(7)	Price risk	Purchases/sales of emission and exchange allowances	N/A(6)	Revenues/Cost of sales

(1) The purpose for holding or issuing does not impact the accounting

method elected for each instrument.

(2) Includes classification of unrealized gains and losses for derivative transactions reclassified to inventory or intangibles upon settlement.

(3) Includes classification for mark-to-market derivatives and amounts reclassified from accumulated other comprehensive income/loss related to cash flow hedges.

(4) See discussion below regarding trading activities.

(5) Natural gas financial swaps and options transacted to economically hedge generation in the PJM region (in our East Coal and East Gas segments).

(6) N/A is not applicable.

(7) Includes emission and

exchange allowances futures for sulfur dioxide (SO_2), nitrogen oxide (NOx) and carbon dioxide (CO_2).

In addition to price risk, we are exposed to credit and operational risk. We have a risk control framework to manage these risks, which include: (a) measuring and monitoring these risks, (b) review and approval of new transactions relative to these risks, (c) transaction validation and (d) portfolio valuation and reporting. We use mark-to-market valuation, value-at-risk and other metrics in monitoring and measuring risk. Our risk control framework includes a variety of separate but complementary processes, which involve commercial and senior management and our Board of Directors. See note 6 for further discussion of our credit policy.

Earnings Volatility from Derivative Instruments. We procure power, natural gas, coal, oil, natural gas transportation and storage capacity and other energy-related commodities to support our business. We may experience volatility in our earnings resulting from contracts receiving accrual accounting treatment while related derivative instruments are marked to market through earnings. As discussed in note 1(b), our financial statements include estimates and assumptions made by management throughout the reporting periods and as of the balance sheet dates. It is reasonable that subsequent to the balance sheet date of September 30, 2010, changes, some of which could be significant, have occurred in the inputs to our various fair value measures, particularly relating to commodity price movements.

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Unrealized gains and losses on energy derivatives consist of both gains and losses on energy derivatives during the current reporting period for derivative assets or liabilities that have not settled as of the balance sheet date and the reversal of unrealized gains and losses from prior periods for derivative assets or liabilities that settled prior to the balance sheet date during the current reporting period.

Cash Flow Hedges. During the first quarter of 2007, we de-designated our remaining cash flow hedges; therefore, as of September 30, 2010 and December 31, 2009, we do not have any designated cash flow hedges. The fair value of our de-designated cash flow hedges are deferred in accumulated other comprehensive loss, net of tax, to the extent the contracts have been effective as hedges, until the forecasted transactions affect earnings. At the time the forecasted transactions affect earnings, we reclassify the amounts in accumulated other comprehensive loss into earnings. Amounts included in accumulated other comprehensive loss are:

	September 30, 2010	
	At the End of the Period	Expected to be Reclassified into Results of Operations in Next 12 Months
	(in millions)	
De-designated cash flow hedges, net of tax[(1)(2)]	$ 22	$ 12

(1) No component of the derivatives gain or loss was excluded from the assessment of effectiveness.

(2) During the three and nine months ended September 30, 2010 and 2009, $0 was recognized in our results of operations as a result of the discontinuance of cash flow hedges because it was probable that the forecasted

transaction would not occur.

Presentation of Derivative Assets and Liabilities. We present our derivative assets and liabilities on a gross basis (regardless of master netting arrangements with the same counterparty). Cash collateral amounts are also presented on a gross basis.

As of September 30, 2010, our commodity derivative assets and liabilities include amounts for non-trading and trading activities as follows:

	Derivative Assets		Derivative Liabilities		Net Derivative Assets
	Current	Long-term	Current	Long-term	(Liabilities)
			(in millions)		
Non-trading	$ 168	$ 51	$ (84)	$ (35)	$ 100
Trading	7		(5)		2
Total derivatives	$ 175	$ 51	$ (89)	$ (35)	$ 102

We have the following derivative commodity contracts outstanding as of September 30, 2010:

		Notional Volumes[2]	
Commodity	Unit[1]	Current	Long-term
		(in millions)	
Power	MWh	(6)	(1)
Capacity energy	MWh	(1)	
Natural gas [3]	MMBtu	25	7
Natural gas basis	MMBtu	(1)	
Coal	MMBtu	93	113

(1) MWh is megawatt hours and MMBtu is million British thermal units.

(2) Negative amounts indicate net forward sales.

(3) Includes current and long-term volumes related to purchases of put options.

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The income (loss) associated with our energy derivatives during the three and nine months ended September 30, 2010 and 2009 is:

Derivatives Not Designated as Hedging Instruments	Three Months Ended September 30, 2010 Revenues	2010 Cost of Sales	2009 Revenues	2009 Cost of Sales
	(in millions)			
Non-Trading Commodity Contracts:				
Unrealized[1]	$ 50	$ 6	$ (25)	$ 34
Realized[2][3][4]	58	(46)	105	(62)
Total non-trading	$ 108	$ (40)	$ 80	$ (28)
Trading Commodity Contracts:				
Unrealized[1]	$	$ (5)	$	$ (2)
Realized[2]		(8)		
Total trading	$	$ (13)	$	$ (2)

Derivatives Not Designated as Hedging Instruments	Nine Months Ended September 30, 2010 Revenues	2010 Cost of Sales	2009 Revenues	2009 Cost of Sales
	(in millions)			
Non-Trading Commodity Contracts:				
Unrealized[1]	$ 99	$ 30	$ (51)	$ 25
Realized[2][3][4]	207	(158)	292	(136)
Total non-trading	$ 306	$ (128)	$ 241	$ (111)
Trading Commodity Contracts:				
Unrealized[1]	$	$ (17)	$	$ (4)
Realized[2]		(11)		20
Total trading	$	$ (28)	$	$ 16

(1) As discussed above, during 2007, we de-designated our remaining cash flow hedges; during

the three and nine months ended September 30, 2010 and 2009, previously measured ineffectiveness gains/losses in revenues reversing related to settlement of the derivative contracts were insignificant.

(2) Does not include realized gains or losses associated with cash month transactions, non-derivative transactions or derivative transactions that qualify for the normal purchase/normal sale exception.

(3) Excludes settlement value of fuel contracts classified as inventory upon settlement.

(4) Includes gains or losses from de-designated cash flow hedges reclassified from accumulated other comprehensive loss related to settlement of the derivative contracts. See note 8.

Trading Activities. Prior to March 2003, we engaged in proprietary trading activities. Trading positions entered into prior to our decision to exit this business are being closed on economical terms or are being retained and settled over the contract terms. In addition, we have current transactions relating to non-core asset management, such as gas storage and transportation contracts not tied to generation assets, which are classified as trading activities. The income (loss) associated with these transactions is:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
	(in millions)			
Revenues	$ 1	$	$ 1	$
Cost of sales	1	5	2	21
Total[(1)]	$ 2	$ 5	$ 3	$ 21

(1) Includes realized and unrealized gains and losses on both derivative instruments and non-derivative instruments.

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(6) Credit Risk

We have a credit policy that governs the management of credit risk, including the establishment of counterparty credit limits and specific transaction approvals. Credit risk is monitored daily and the financial condition of our counterparties is reviewed periodically. We try to mitigate credit risk by entering into contracts that permit netting and allow us to terminate upon the occurrence of certain events of default. We measure credit risk as the replacement cost for our derivative positions plus amounts owed for settled transactions.

Our credit exposure is based on (a) derivative assets and accounts receivable from our counterparties (each included in our consolidated balance sheet) and (b) contracts classified as normal purchase/normal sale and non-derivative contractual commitments (each not included in our consolidated balance sheet except for any related accounts receivable), all after taking into consideration netting within each contract and any master netting contracts with counterparties. We think this represents the maximum potential loss we could incur if our counterparties to the contracts discussed above failed to perform according to their contract terms.

As of September 30, 2010, our credit exposure is summarized as follows:

Credit Rating Equivalent	Exposure Before Collateral[1]	Credit Collateral Held[2]	Exposure Net of Collateral	Number of Counterparties >10%	Net Exposure of Counterparties >10%
			(dollars in millions)		
Investment grade	$ 179	$ 5	$ 174	3[3]	$ 137
Non-investment grade	8		8		
No external ratings:					
Internally rated Investment grade	24		24	1[4]	23
Internally rated Non-investment grade	19	13	6		
Total	$ 230	$ 18	$ 212	4	$ 160

(1) The table includes amounts related to certain contracts classified as discontinued operations in our consolidated balance sheets. These contracts settle through the expiration date in 2013.

(2)

Collateral consists of cash, standby letters of credit and other forms approved by management.

(3) These counterparties are two utility companies and a power grid operator.

(4) This counterparty is a financial institution.

As of December 31, 2009, three investment grade counterparties (a power grid operator, a utility company and a financial institution) represented 56% ($138 million) of our credit exposure net of collateral held. As of December 31, 2009, we had $45 million of collateral held.

Based on our current credit ratings, any additional collateral postings that would be required from us as a result of a credit downgrade would be immaterial.

We have cash collateral posted and letters of credit issued as follows:

	September 30, 2010		December 31, 2009	
	Cash	Letters of Credit[1]	Cash	Letters of Credit[1]
	(in millions)			
Commodity contracts[2]	$ 99	$ 48	$ 207	$ 52
Derivative contracts receiving mark-to-market accounting treatment[2][3]	$ 20	$ 2	$ 97	$ 5
Other[4]	$ 34	$	$ 47	$

(1) See note 9.

(2) Includes activity for both continuing and discontinued operations.

(3) These amounts are included in the amounts above for commodity contracts.

(4) Represents cash posted under surety bonds related to environmental obligations to the Pennsylvania Department of Environmental Protection.

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(7) Long-Lived Assets Impairments

We periodically evaluate the recoverability of our long-lived assets (property, plant and equipment and intangible assets), which involves significant judgment and estimates, when there are certain indicators that the carrying value of these assets may not be recoverable. As of September 30, 2010, we had $4.4 billion of long-lived assets. This estimate affects all segments, which hold 99% of our total net property, plant and equipment and net intangible assets. Our East Coal segment holds the largest portion of our net property, plant and equipment and net intangible assets at 57% of our consolidated total.

Based on the further decline of forward commodity prices, our asset recoverability review was updated from March 31, 2010 to September 30, 2010. Our asset recoverability review as of September 30, 2010 indicated that two plants, our Titus plant and our New Castle plant (each in our East Coal segment), needed to be measured at fair value to determine if impairments existed.

Following our current methodology (as described below), as of September 30, 2010, we had four additional plants and related intangible assets with a combined carrying value of $597 million, where the undiscounted cash flows were close to the carrying values. If market conditions or environmental and regulatory assumptions change negatively in the future, it is likely that these four plants (and possibly others) could be impaired.

Our asset recoverability review as of March 31, 2010 indicated that two plants, our Elrama plant and our Niles plant (each in our East Coal segment), needed to be measured at fair value to determine if impairments existed. See notes 2(g), 4 and 5 to our consolidated financial statements in our Form 10-K for further discussion.

Key Assumptions. The following summarizes some of the most significant estimates and assumptions used in evaluating our plant level undiscounted cash flows as of September 30, 2010 and March 31, 2010. The ranges for the fundamental view assumptions are to account for variability by year and region.

	September 30, 2010	**March 31, 2010**
Undiscounted Cash Flow Scenarios Weightings:		
5-year market forecast with escalation(1)(2)	50%	50%
5-year market forecast with fundamental view(1)	50%	50%
Range of Assumptions in Fundamental View:		
Demand for power growth per year	1%-2%	1%-2%
After-tax rate of return on new construction(3)	6.5%-9.5%	6.5%-9.5%
Spread between natural gas and coal prices, $/MMBtu(4)	$3-$5	$3-$5

(1) For each scenario, the first five years of cash flows are the same.

(2) We assumed an annual 2.5% escalation percentage beyond year five.

(3) The low to mid part of the range represents natural gas-fired

plants required returns and the mid to high part of the range represents coal-fired and nuclear plants required returns.

(4) Natural gas and coal prices are prior to transportation costs.

We estimate the undiscounted cash flows of our plants based on a number of subjective factors, including: (a) appropriate weighting of undiscounted cash flow scenarios, as shown in the table above, (b) forecasts of future power generation margins, (c) estimates of our future cost structure, (d) environmental assumptions, (e) time horizon of cash flow forecasts and (f) estimates of terminal values of plants, if necessary, from the eventual disposition of the assets. We did not include the cash flows associated with our economic hedges in our PJM region (East Coal and East Gas segments) as these cash flows are not specific to any one plant.

Under the 5-year market forecast with escalation scenario, we use the following data: (a) forward market curves for commodity prices as of September 21, 2010 (for the third quarter review) and March 16, 2010 (for the first quarter review) for the first five years, (b) cash flow projections through the plant s estimated remaining useful life and (c) escalation factor of cash flows of 2.5% per year after year five.

Under the 5-year market forecast with fundamental view scenario, we model all of our plants and those of others in the regions in which we operate using these assumptions: (a) forward market curves for commodity prices as of September 21, 2010 (for the third quarter review) and March 16, 2010 (for the first quarter review) for the first five years; (b) ranges shown in the table above used in developing our fundamental view beyond five years; (c) the markets in which we operate will continue to be deregulated and earn margins based on forward or projected market prices; (d) projected market prices for energy and capacity will be set by the forecasted available supply and level of forecasted demand new supply will enter markets when market prices and associated returns, including any assumed subsidies for renewable energy, are sufficient to achieve minimum return requirements; (e) minimum return requirements on future construction of new generation facilities, as shown in the table above, will likely be driven or influenced by utilities, which we expect will have a lower cost of capital than merchant generators; (f) various ranges of environmental regulations, including those for SO_2, NO_x and greenhouse gas emissions; and (g) cash flow projections through the plant s estimated remaining useful life.

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Fair Value. Generally, fair value will be determined using an income approach or a market-based approach. Under the income approach, the future cash flows are estimated as described above and then discounted using a risk-adjusted rate. Under a market-based approach, we may also consider prices of similar assets, consult with brokers or employ other valuation techniques.

The following are key assumptions used in our fair value analyses as of September 30, 2010 and March 31, 2010 for our four plants for which the undiscounted cash flows did not exceed the net book value of the long-lived assets.

	September 30, 2010		March 31, 2010	
	Titus	New Castle	Elrama	Niles
Valuation approach weightings:				
Income approach	100%	100%	100%	100%
Market-based approach	0%	0%	0%	0%
Risk-adjusted discount rate for the estimated cash flows	13%	15%	15%	15%

We only used the income approach as we think no relevant market data exists for these four plants for which we were required to estimate fair value. The discount rates reflect the uncertainty of the plants cash flows and their ability to support debt, and was determined considering factors such as the potential for future capacity revenues and regulatory, commodity and macroeconomic conditions.

We determined that our Titus plant, which consists of property, plant and equipment, was impaired by $74 million as of September 30, 2010. We determined that our New Castle plant, which consists of property, plant and equipment, was impaired by $39 million as of September 30, 2010. These impairments were primarily as a result of the further decline of forward commodity prices. We think the remaining net book values of $31 million for Titus and $6 million for New Castle represent our best estimates of fair values as of September 30, 2010.

We determined that our Elrama plant, which consists of property, plant and equipment, was impaired by $193 million as of March 31, 2010. We determined that our Niles plant, which consists of property, plant and equipment, was impaired by $55 million as of March 31, 2010. These impairments were primarily as a result of the further decline of forward commodity prices. We think the remaining net book values of $68 million for Elrama and $26 million for Niles represent our best estimates of fair values as of March 31, 2010.

Certain disclosures are required about nonfinancial assets and liabilities measured at fair value on a nonrecurring basis. This applies to our long-lived assets for which we were required to determine fair value. A fair value hierarchy exists for inputs used in measuring fair value that maximizes the use of observable inputs (Level 1 or Level 2) and minimizes the use of unobservable inputs (Level 3) by requiring that the observable inputs be used when available. See note 4 for further discussion about the three levels. These assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and affects the valuation of fair value and the assets placement within the fair value hierarchy levels.

	September 30, 2010			Q3 2010 Impairment
	Level 1	Level 2	Level 3	Charges
		(in millions)		
Titus property, plant and equipment[1]	$	$	$ 31	$ 74
New Castle property, plant and equipment[2]			6	39
Total	$	$	$ 37	$ 113

(1) Titus is in our East Coal segment.

(2) New Castle is in our East Coal segment.

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	March 31, 2010 Level 1		Level 2 (in millions)		Level 3		Q1 2010 Impairment Charges	
Elrama property, plant and equipment[1]	$		$		$	68	$	193
Niles property, plant and equipment[2]						26		55
Total	$		$		$	94	$	248

(1) Elrama is in our East Coal segment.

(2) Niles is in our East Coal segment.

Effect if Different Assumptions Used. The estimates and assumptions used to determine whether long-lived assets are recoverable or whether impairment exists are subject to a high degree of uncertainty. Different assumptions as to power prices, fuel costs, our future cost structure, environmental assumptions and remaining useful lives and ultimate disposition values of our plants would result in estimated future cash flows that could be materially different than those considered in the recoverability assessments as of September 30, 2010 and March 31, 2010 and could result in having to estimate the fair value of other plants.

Use of a different risk-adjusted discount rate would result in fair value estimates for the four plants for which we recorded an impairment during the three months ended September 30 or March 31, 2010 that could be materially greater than or less than the fair value estimates as of each applicable date. Any future fair value estimates for the plants where an impairment has been recognized that are greater than the fair value estimates at the time of impairment recognition will not result in reversal of previously recognized impairments.

(8) Comprehensive Income (Loss)

The components of total comprehensive income (loss) are:

	Three Months Ended September 30, 2010		2009		Nine Months Ended September 30, 2010 (in millions)		2009	
Net income (loss)	$	23	$	(15)	$	(426)	$	637
Other comprehensive income (loss), net of tax:								
Deferred benefits		2				(1)		1
Reclassification of net deferred loss from cash flow hedges into net income/loss		4		5		12		13
Unrealized gains (losses) on available-for-sale securities		(1)				(2)		3
Comprehensive income (loss)	$	28	$	(10)	$	(417)	$	654

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(9) Debt

Outstanding debt:

	September 30, 2010			December 31, 2009		
	Weighted Average Stated Interest Rate(1)	**Long-term**	**Current**	**Weighted Average Stated Interest Rate(1)**	**Long-term**	**Current**
	(in millions, except interest rates)					
Facilities, Bonds and Notes:						
RRI Energy:						
Senior secured revolver due 2012(2)	2.04%	$	$	1.98%	$	$
Senior secured notes due 2014(2)	6.75	279		6.75	279	
Senior unsecured notes due 2014	7.625	575		7.625	575	
Senior unsecured notes due 2017	7.875	725		7.875	725	
Subsidiary Obligations:						
Orion Power Holdings, Inc. senior notes due 2010 (unsecured)(3)				12.00		400
PEDFA(2)(4) fixed-rate bonds due 2036	6.75	371		6.75	371	
Total facilities, bonds and notes		1,950			1,950	400
Other:						
Adjustment to fair value of debt(5)						5
Total other debt						5
Total debt		$ 1,950	$		$ 1,950	$ 405

(1) The weighted average stated interest rates are as of September 30, 2010 or December 31, 2009.

(2) See note 2 regarding the proposed refinancing of this debt in connection with the merger with Mirant.

(3) We paid off this debt in May 2010.

(4) These bonds were issued for our Seward plant.

(5) Debt acquired in the Orion Power acquisition was adjusted to fair value as of the acquisition date. Included in interest expense is amortization of $3 million for valuation adjustments for debt during the three months ended September 30, 2009 and $5 million and $9 million during the nine months ended September 30, 2010 and 2009, respectively.

Amounts borrowed and available for borrowing under our revolving credit agreements as of September 30, 2010 are:

	Total Committed Credit		Drawn Amount		Letters of Credit		Unused Amount	
			(in millions)					
RRI Energy senior secured revolver due 2012	$	500	$		$		$	500
RRI Energy letter of credit facility due 2014		250				82		168
Total	$	750	$		$	82	$	668

(10) Earnings (Loss) Per Share

The amounts used in the basic and diluted earnings (loss) per common share computations are the same:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009

				(shares in thousands)				
Income (loss) from continuing operations (basic and diluted)	$	23	$	(19)	$	(430)	$	(228)

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The diluted weighted averages shares calculation follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(shares in thousands)			
Weighted average shares outstanding (basic)	353,520	351,561	353,434	350,908
Plus: Incremental shares from assumed conversions:				
Stock options	26	(1)	(1)	(1)
Restricted stock	159	(1)	(1)	(1)
Weighted average shares outstanding (diluted)	353,705	351,561	353,434	350,908

(1) As we incurred a loss from continuing operations for this period, diluted loss per share is calculated the same as basic loss per share.

We excluded the following items from diluted earnings (loss) per common share because of the anti-dilutive effect:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(shares in thousands)			
Shares excluded from the calculation of diluted earnings/loss per share	N/A(1)	619(2)	255(2)	501(2)
Shares excluded from the calculation of diluted earnings/loss per share because the exercise price exceeded the average market price	6,015(3)	4,970(3)	5,553(3)	4,970(3)

(1) Not applicable as we included the item in the calculation of diluted

earnings/loss per share.

(2) Potential shares include stock options and restricted stock.

(3) Includes stock options.

(11) Income Taxes

(a) Tax Rate Reconciliation.

A reconciliation of the federal statutory income tax rate to the effective income tax rate for our continuing operations is:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Federal statutory rate	35%	(35)%	(35)%	(35)%
Additions (reductions) resulting from:				
Federal valuation allowance	31(1)	134(2)	48(3)	4
State income taxes, net of federal income taxes	5(4)	(20) (5)	6(6)	(2)
Other	(25)	30(7)(8)		1(8)
Effective rate	46%	109%	19%	(32)%

(1) Of this percentage, $13 million (31%) relates to additional valuation allowance.

(2) Of this percentage, $12 million (134%) relates to additional valuation allowance.

(3) Of this percentage, $172 million (48%) relates to additional

valuation allowance.

(4) Of this percentage, $4 million (11%) relates to additional valuation allowance.

(5) Of this percentage, $(2) million (20%) relates to a reduction in valuation allowance.

(6) Of this percentage, $42 million (12%) relates to additional valuation allowance.

(7) Of this percentage, $3 million (34%) relates to the disallowance of net operating loss carryforward.

(8) Includes $15 million of a valuation allowance release offset by $15 million of expired foreign net operating loss carryforwards.

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(b) Valuation Allowances.

We assess our future ability to use federal, state and foreign net operating loss carryforwards, capital loss carryforwards and other deferred tax assets using the more-likely-than-not criteria. These assessments include an evaluation of our recent history of earnings and losses, future reversals of temporary differences and identification of other sources of future taxable income, including the identification of tax planning strategies in certain situations.

Our valuation allowances for deferred tax assets are:

	Federal	State
	(in millions)	
As of December 31, 2009	$ 129	$ 135
Changes in valuation allowances	112	32
As of March 31, 2010	241	167
Changes in valuation allowance	47	6
As of June 30, 2010	288	173
Changes in valuation allowances	13	4
Changes in valuation allowance in accumulated other comprehensive loss	(1)	
As of September 30, 2010	$ 300	$ 177

(c) Income Tax Uncertainties.

We may only recognize the tax benefit for financial reporting purposes from an uncertain tax position when it is more-likely-than-not that, based on the technical merits, the position will be sustained by taxing authorities or the courts. The recognized tax benefits are measured as the largest benefit having a greater than fifty percent likelihood of being realized upon settlement with a taxing authority. We classify accrued interest and penalties related to uncertain income tax positions in income tax expense/benefit.

Our unrecognized federal and state tax benefits changed during the nine months ended September 30, 2010 as follows (in millions):

Balance, December 31, 2009	$ 3
Increases related to prior years	12
Decreases related to prior years	(11)
Increases related to current year	
Settlements	
Lapses in the statute of limitations	
Balance, September 30, 2010	$ 4

Our unrecognized federal and state tax benefits did not change significantly during the nine months ended September 30, 2009.

We expect to continue discussions with taxing authorities regarding tax positions related to the following, and think it is reasonably possible some of these matters could be resolved in the next 12 months; however, we cannot estimate the range of changes that might occur: (a) the $351 million charge during 2005 to settle certain civil litigation and claims relating to the Western states energy crisis; and (b) the timing of tax deductions as a result of negotiations with respect to California-related revenue, depreciation and emission allowances.

We are in ongoing discussions with the Internal Revenue Service (IRS) regarding the timing of revenue recognition and tax deductions with respect to certain California-related items in our 2002 short taxable period return (subsequent to our separation from CenterPoint Energy, Inc. (CenterPoint)). The IRS has informed us it expects to issue a notice of denial of our administrative claim for refund involving these California-related items and we expect to institute refund litigation with respect to this claim in the U.S. District Court or U.S. Court of Federal Claims. In order to set a jurisdictional prerequisite to institute such a refund suit, we expect to make a payment of approximately $55 million to $60 million (which includes an asserted tax liability of $34 million plus interest) sometime during the next twelve months and record a related receivable. If the IRS were to ultimately prevail in this matter, there would be an increase to our income tax expense. The payment will be refunded with interest if we are successful in the litigation.

(12) Guarantees and Indemnifications

We have guaranteed some non-qualified benefits of CenterPoint s existing retirees at September 20, 2002. The estimated maximum potential amount of future payments under the guarantee is approximately $51 million as of September 30, 2010 and no liability is recorded in our consolidated balance sheet for this item.

We also guarantee the PEDFA fixed-rate bonds, which are included in our consolidated balance sheet as outstanding debt ($371 million are in our consolidated balance sheets as of September 30, 2010 and December 31, 2009). Our guarantees are secured by the same collateral as our senior secured 6.75% notes. The guarantees require us to comply with covenants similar to those in the senior secured 6.75% notes indenture. The PEDFA bonds will become secured by certain assets of our Seward power plant if the collateral supporting both the senior secured 6.75% notes and our guarantees are released. Our maximum potential obligation under the guarantees is for payment of the principal and related interest charges at a fixed rate of 6.75%. During 2009, we purchased $129 million ($92 million of which was classified as discontinued operations) of the PEDFA bonds and are the holder of these repurchased bonds. Therefore, the net amount payable by us would not exceed the amount of PEDFA bonds outstanding, excluding the PEDFA bonds we hold. See note 9.

We guaranteed payments to a third party relating to energy sales during December 2000 from El Dorado Energy, LLC, a former investment. In April 2010, the third party agreed to settle litigation arising from the 2000-2001 energy crises. Based on estimates from the third party and as a result, we recorded a $17 million charge during the three months ended March 31, 2010, which is included in Western states litigation and similar settlements in our statement of operations and other current liabilities in our consolidated balance sheet as of September 30, 2010. The third party s settlement has not yet been filed with nor approved by the FERC. We currently expect to make this payment during 2010 or early 2011. This estimate is subject to change.

In connection with the sale of our Northeast C&I contracts in December 2008, we guaranteed some former customers performance to the buyer. We estimate the most probable maximum potential amount of future payments under the guarantee is $6 million as of September 30, 2010. As of September 30, 2010 and December 31, 2009, we have recorded an insignificant amount in our consolidated balance sheets associated with this guarantee.

We enter into contracts that include indemnification and guarantee provisions. In general, we enter into contracts with indemnities for matters such as breaches of representations and warranties and covenants contained in the contract and/or against certain specified liabilities. Examples of these contracts include asset purchase and sales agreements, service agreements and procurement agreements. In our debt agreements, we typically indemnify against liabilities that arise from the preparation, entry into, administration or enforcement of the agreement.

Except as otherwise noted, we are unable to estimate our maximum potential exposure under these agreements until an event triggering payment occurs. We do not expect to make any material payments under these agreements.

(13) Contingencies

We are party to many legal proceedings, some of which may involve substantial amounts. Unless otherwise noted, we cannot predict the outcome of the matters described below.

(a) Pending Natural Gas Litigation.

We are party to five lawsuits, several of which are class action lawsuits, in state and federal courts in Kansas, Missouri, Nevada and Wisconsin. These lawsuits relate to alleged conduct to increase natural gas prices in violation of antitrust and similar laws. The lawsuits seek treble or punitive damages, restitution and/or expenses. The lawsuits also name a number of unaffiliated energy companies as parties. In lawsuits related to foregoing alleged conduct, in April 2010, the Tennessee Supreme Court reversed the Court of Appeals and dismissed all claims, and in September 2010, the Missouri Supreme Court sent a case back to the Court of Appeals, where the dismissal was reaffirmed.

(b) Environmental Matters.

New Source Review Matters. The United States Environmental Protection Agency (EPA) and various states are investigating compliance of coal-fueled electric generating plants with the pre-construction permitting requirements of the Clean Air Act known as New Source Review. In recent years, the EPA has made information requests for all of our coal plants other than the Seward plant. We are corresponding or have corresponded with the EPA regarding all of these requests. The EPA agreed to share information relating to its investigations with state environmental agencies.

In January 2009, we received a Notice of Violation from the EPA alleging that past work at our Shawville, Portland and Keystone plants violated the agency s regulations regarding New Source Review.

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In December 2007, the New Jersey Department of Environmental Protection (NJDEP) filed suit against us in the United States District Court in Pennsylvania, alleging that New Source Review violations occurred at one of our plants located in Pennsylvania. The suit seeks installation of best available control technologies for each pollutant, to enjoin us from operating the plant if it is not in compliance with the Clean Air Act and civil penalties. The suit also names three past owners of the plant as defendants. In March 2009, the Connecticut Department of Environmental Protection became an intervening party to the suit.

We think that the projects listed by the EPA and the projects subject to the NJDEP suit were conducted in compliance with applicable regulations. However, any final finding that we violated the New Source Review requirements could result in significant capital expenditures associated with the implementation of emissions reductions on an accelerated basis and possible penalties. Most of these work projects were undertaken before our ownership of those facilities. We think we are indemnified by or have the right to seek indemnification from the prior owners for certain losses and expenses that we may incur from activities occurring prior to our ownership.

Ash Disposal Landfill Closures. We are responsible for environmental costs related to the future closures of seven ash disposal landfills. We recorded the estimated discounted costs ($17 million and $18 million as of September 30, 2010 and December 31, 2009, respectively) associated with these environmental liabilities as part of our asset retirement obligations. See note 2(m) to our consolidated financial statements in our Form 10-K.

Remediation Obligations. We are responsible for environmental costs related to site contamination investigations and remediation requirements at four power plants in New Jersey. We recorded the estimated long-term liability for the remediation costs of $7 million and $8 million as of September 30, 2010 and December 31, 2009, respectively.

Conemaugh Actions. In April 2007, PennEnvironment and the Sierra Club filed a citizens suit against us in the United States District Court, Western District of Pennsylvania to enforce provisions of the water discharge permit for the Conemaugh plant, of which we are the operator and have a 16.45% interest. PennEnvironment and the Sierra Club seek civil penalties, remediation and an injunction against further violations. We are confident that the Conemaugh plant has operated and will continue to operate in material compliance with its water discharge permit, its consent order agreement with the Pennsylvania Department of Environmental Protection (PADEP), and related state and federal laws. In December 2009, the District Court ordered that the case be dismissed. In January 2010, PennEnvironment and the Sierra Club requested that the court reconsider its ruling. In September 2010, the court ruled that the December 2009 dismissal was erroneous and has reinstated the case. This ruling does not change our general view of the case: that we have complied with our permit and consent order and agreement with the PADEP. If PennEnvironment and the Sierra Club are ultimately successful, we could incur additional capital expenditures associated with the implementation of discharge reductions and penalties, which we do not think would be material.

Global Warming. In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a suit in the United States District Court for the Northern District of California against us and 23 other electric generating and oil and gas companies. The lawsuit seeks damages of up to $400 million for the cost of relocating the village allegedly because of global warming caused by the greenhouse gas emissions of the defendants. In late 2009, the District Court ordered that the case be dismissed and the plaintiffs appealed. We are also a party to Comer v. Murphy Oil, where a group of Mississippi residents and landowners allege the defendants greenhouse gas emissions contributed to the force of Hurricane Katrina. The plaintiffs have not specified the amount of damages they are seeking. In May 2010, the United States Court of Appeals for the Fifth Circuit ordered that the case be dismissed with prejudice. In September 2010, the plaintiffs filed a petition for writ of certiorari with the United States Supreme Court. While we think claims such as these lack legal merit, it is possible that this trend of climate change litigation may continue.

(c) Other.

Excess Mitigation Credits. From January 2002 to April 2005, CenterPoint applied excess mitigation credits (EMCs) to its monthly charges to retail energy providers. The PUCT imposed these credits to facilitate the transition to competition in Texas, which had the effect of lowering the retail energy providers monthly charges payable to CenterPoint. CenterPoint represents that the portion of those EMCs credited to our former Texas retail business totaled $385 million. In its stranded cost case, CenterPoint sought recovery of all EMCs credited to all retail electric providers, including our former Texas retail business, and the PUCT ordered that relief. On appeal, the Texas Third Court of Appeals ruled that CenterPoint s stranded cost recovery should exclude EMCs credited to our former Texas retail business for price-to-beat customers. The case is now before the Texas Supreme Court. In November 2008, CenterPoint asked us to agree to suspend any limitations periods that might exist for possible claims against us or our former Texas retail business if it is ultimately not allowed to include in its stranded cost calculation EMCs credited to our former Texas retail business. We agreed to suspend only unexpired deadlines, if any, that may apply to a CenterPoint claim relating to EMCs credited to our former Texas retail business.

CenterPoint Indemnity. We have agreed to indemnify CenterPoint against certain losses relating to the lawsuits described in note 13(a) under Pending Natural Gas Litigation.

Texas Franchise Audit. The state of Texas has issued assessment orders indicating an estimated tax liability of approximately $60 million (including interest and penalties of $22 million) relating primarily to the sourcing of receipts for 2000 through 2006. We are contesting the audit assessments related to this issue and have begun the administrative appeals process. If we unsuccessfully exhaust our administrative appeals, the state of Texas will demand payment, at which time we would pay up to $38 million in franchise tax and $22 million in interest and penalties and record a related receivable for $60 million. We expect the administrative appeals process to conclude during the next twelve months. If the state of Texas were to ultimately prevail in this matter, there would be an increase to operating expense.

Refund Contingency Related to Transportation Rates. In September 2008, Kern River Gas Transmission Company (Kern), a natural gas pipeline company, and certain of its shippers entered into a settlement agreement regarding Kern s transportation rates to which we were a party. The agreement resulted in a refund to us of $30 million during 2008 (recorded as a current liability). In 2009, the Federal Energy Regulatory Commission (FERC) rejected the settlement agreement and directed Kern to recalculate the refunds. We do not expect any adjustments to be material.

(d) Proposed Merger with Mirant.

In April 2010, RRI Energy, Mirant and the members of the Mirant board of directors were named defendants in four purported class action lawsuits filed in the Superior Court of Fulton County, Georgia, brought on behalf of proposed classes consisting of holders of Mirant common stock, excluding the defendants and their affiliates: *Rosenbloom v. Cason, et al.,* No. 2010CV184223, filed April 13, 2010; *The Vladmir Gusinsky Living Trust v. Muller, et al.*, No. 2010CV184331, filed April 15, 2010; *Ng v. Muller, et al.*, No. 2010CV184449, filed April 16, 2010; and *Bayne v. Muller, et al.*, No. 2010CV184648, filed April 21, 2010. RRI Energy Holdings, Inc., a wholly-owned subsidiary of RRI Energy formed for the purpose of effecting the merger, was also named a defendant in three of the lawsuits. The complaints allege, among other things, that the individual defendants breached their fiduciary duties by failing to maximize the value to be received by Mirant s public stockholders, and that the other defendants aided and abetted the individual defendants breaches of fiduciary duties. In three of the actions, amended complaints have been filed adding allegations that defendants breached their fiduciary duties by failing to disclose certain information in the preliminary joint proxy statement/prospectus of RRI Energy and Mirant. The complaints seek, among other things, (a) to enjoin defendants from consummating the merger, (b) rescission of the merger, if completed and/or (c) granting the class members any profits or benefits allegedly improperly received by defendants in connection with the merger. Motions to dismiss the complaints for failure to state a claim have been filed on behalf of all of the defendants.

On August 17, 2010, the Court entered an order, consented to by all parties, consolidating the four cases under the caption *In re Mirant Corporation Shareholder Litigation,* No. 2010CV184223, directing that the amended complaint in *Rosenbloom v. Cason, et al.*, No. 2010CV1c824223, serve as the operative complaint, and appointing co-lead counsel. On August 26, 2010, the parties entered into a memorandum of understanding under the terms of which the parties will negotiate in good faith to enter into a stipulation of settlement based on additional disclosures, to be presented to the Court for approval following consummation of the merger.

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(14) Pension and Postretirement Benefits

We sponsor multiple defined benefit pension plans. We provide subsidized postretirement benefits to some bargaining employees but generally do not provide them to non-bargaining employees. See note 11 to our consolidated financial statements in our Form 10-K for additional information about pension and postretirement benefits.

	Pension Three Months Ended September 30,		Postretirement Three Months Ended September 30,	
	2010	2009	2010	2009
	(in millions)			
Service cost	$ 1	$ 1	$ 1	$
Interest cost	2	1	1	1
Expected return on plan assets	(1)	(1)		
Net amortization(1)		1		
Net curtailments (gain) loss		1		(1)
Special termination benefits		1		1
Net periodic benefit costs	$ 2	$ 4	$ 2	$ 1

	Pension Nine Months Ended September 30,		Postretirement Nine Months Ended September 30,	
	2010	2009	2010	2009
	(in millions)			
Service cost	$ 3	$ 4	$ 1	$ 1
Interest cost	5	4	3	3
Expected return on plan assets	(4)	(3)		
Net amortization(1)	1	3		1
Net curtailments (gain) loss		1		(1)
Special termination benefits		1		1
Net periodic benefit costs	$ 5	$ 10	$ 4	$ 5

(1) Net amortization amount includes prior service costs and actuarial gains and losses.

(15) Collective Bargaining Agreements

As of September 30, 2010, approximately 45% of our employees are subject to collective bargaining agreements. Less than five percent of our employees are subject to collective bargaining agreements that will expire by September 30, 2011.

(16) Supplemental Guarantor Information

Our wholly-owned subsidiaries are either (a) full and unconditional guarantors, jointly and severally, or (b) non-guarantors of the senior secured notes. Orion Power Holdings, Inc. and its consolidated subsidiaries became guarantors in June 2010 as a result of the pay off of its senior notes in May 2010. We have reclassified 2009 disclosures to be comparable to 2010.

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Condensed Consolidating Statements of Operations.

	Three Months Ended September 30, 2010				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments (1)	Consolidated
Revenues	$	$ 704	$ 191	$ (198)	$ 697
Cost of sales		423	80	(198)	305
Operation and maintenance		63	53		116
General and administrative		13	8		21
Gains on sales of assets and emission and exchange allowances, net		(1)			(1)
Long-lived assets impairments		39	74		113
Depreciation and amortization		53	12		65
Total		590	227	(198)	619
Operating income (loss)		114	(36)		78
Income of equity investments of consolidated subsidiaries	2	(67)		65	
Interest expense	(33)	(6)			(39)
Interest income (expense) affiliated companies, net	19	(3)	(16)		
Other, net		2			2
Total other income (expense)	(12)	(74)	(16)	65	(37)
Income (loss) from continuing operations before income taxes	(12)	40	(52)	65	41
Income tax expense (benefit)	(35)	38	15		18
Net income (loss)	$ 23	$ 2	$ (67)	$ 65	$ 23

	Three Months Ended September 30, 2009				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments (1)	Consolidated
Revenues	$	$ 513	$ 126	$ (132)	$ 507
Cost of sales		344	54	(131)	267
Operation and maintenance		62	54	(1)	115
General and administrative		9	14		23
			(1)		(1)

Gains on sales of assets and emission and exchange allowances, net					
Depreciation and amortization		55	13		68
Total		470	134	(132)	472
Operating income (loss)		43	(8)		35
Income (loss) of equity investments of consolidated subsidiaries	14	(15)		1	
Interest expense	(37)	(10)		2	(45)
Interest income (expense) affiliated companies, net	19	(4)	(13)	(2)	
Other, net		1			1
Total other expense	(4)	(28)	(13)	1	(44)
Income (loss) from continuing operations before income taxes	(4)	15	(21)	1	(9)
Income tax expense (benefit)	5	16	(7)	(4)	10
Loss from continuing operations	$ (9)	$ (1)	$ (14)	$ 5	$ (19)
Income (loss) from discontinued operations	(6)	4	6		4
Net income (loss)	$ (15)	$ 3	$ (8)	$ 5	$ (15)

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	Nine Months Ended September 30, 2010				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments (1)	Consolidated
Revenues	$	$ 1,717	$ 502	$ (517)	$ 1,702
Cost of sales		1,141	211	(515)	837
Operation and maintenance		256	206	(2)	460
General and administrative		42	35		77
Western states litigation and similar settlements		17			17
Gains on sales of assets and emission and exchange allowances, net		(2)			(2)
Long-lived assets impairments		287	74		361
Depreciation and amortization		158	38		196
Total		1,899	564	(517)	1,946
Operating loss		(182)	(62)		(244)
Loss of equity investments of consolidated subsidiaries	(269)	(128)		397	
Interest expense	(99)	(22)	(1)		(122)
Interest income (expense) affiliated companies, net	60	(13)	(47)		
Other, net		5			5
Total other expense	(308)	(158)	(48)	397	(117)
Loss from continuing operations before income taxes	(308)	(340)	(110)	397	(361)
Income tax expense (benefit)	121	(70)	18		69
Loss from continuing operations	(429)	(270)	(128)	397	(430)
Income from discontinued operations	3		1		4
Net loss	$ (426)	$ (270)	$ (127)	$ 397	$ (426)

	Nine Months Ended September 30, 2009				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments (1)	Consolidated

Revenues	$	$ 1,352	$ 414	$ (403)	$ 1,363
Cost of sales		1,033	238	(399)	872
Operation and maintenance		251	182	(4)	429
General and administrative		25	55		80
Gains on sales of assets and emission and exchange allowances, net		(20)	(1)		(21)
Depreciation and amortization		165	38		203
Total		1,454	512	(403)	1,563
Operating loss		(102)	(98)		(200)
Loss of equity investments of consolidated subsidiaries	(163)	(74)		237	
Debt extinguishments gains	1				1
Interest expense	(111)	(32)		6	(137)
Interest income	1				1
Interest income (expense) affiliated companies, net	54	(11)	(37)	(6)	
Other, net		1			1
Total other expense	(218)	(116)	(37)	237	(134)
Loss from continuing operations before income taxes	(218)	(218)	(135)	237	(334)
Income tax benefit	(6)	(43)	(56)	(1)	(106)
Loss from continuing operations	(212)	(175)	(79)	238	(228)
Income (loss) from discontinued operations	849	14	2		865
Net income (loss)	$ 637	$ (161)	$ (77)	$ 238	$ 637

(1) These amounts relate to either (a) eliminations and adjustments recorded in the normal consolidation process or (b) reclassifications recorded as a result of differences in classifications at the subsidiary levels

compared to the
consolidated level.

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Condensed Consolidating Balance Sheets.

	September 30, 2010				
	RRI Energy	Guarantors	Non-Guarantors	Adjustments (1)	Consolidated
			(in millions)		
ASSETS					
Current Assets:					
Cash and cash equivalents	$ 778	$	$ 3	$	$ 781
Restricted cash		5	2		7
Accounts and notes receivable, principally customer, net	13	109	7	(5)	124
Accounts and notes receivable affiliated companies	2,025	552	141	(2,718)	
Inventory		184	97		281
Derivative assets		161	14		175
Other current assets	34	114	72	(9)	211
Current assets of discontinued operations	19	36		(14)	41
Total current assets	2,869	1,161	336	(2,746)	1,620
Property, Plant and Equipment, net		3,449	674		4,123
Other Assets:					
Other intangibles, net		198	93		291
Notes receivable affiliated companies	1,216	566		(1,782)	
Equity investments of consolidated subsidiaries	2,009	156	18	(2,183)	
Derivative assets		50	1		51
Other long-term assets	39	729	362	(646)	484
Long-term assets of discontinued operations		3			3
Total other assets	3,264	1,702	474	(4,611)	829
Total Assets	$ 6,133	$ 6,312	$ 1,484	$ (7,357)	$ 6,572
LIABILITIES AND EQUITY					
Current Liabilities:					
Accounts payable, principally trade	$	$ 78	$ 21	$	$ 99
Accounts and notes payable affiliated companies		2,149	569	(2,718)	
Derivative liabilities		41	48		89

Other current liabilities	41	215	24	(14)	266
Current liabilities of discontinued operations	2	27		(14)	15
Total current liabilities	43	2,510	662	(2,746)	469
Other Liabilities:					
Notes payable affiliated companies		1,238	544	(1,782)	
Derivative liabilities		7	28		35
Other long-term liabilities	667	177	68	(646)	266
Long-term liabilities of discontinued operations	5	8			13
Total other liabilities	672	1,430	640	(2,428)	314
Long-term Debt	1,579	371			1,950
Commitments and Contingencies					
Temporary Equity					
Stock-based Compensation	7				7
Total Stockholders Equity	3,832	2,001	182	(2,183)	3,832
Total Liabilities and Equity	$ 6,133	$ 6,312	$ 1,484	$ (7,357)	$ 6,572

	December 31, 2009				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments (1)	Consolidated
ASSETS					
Current Assets:					
Cash and cash equivalents	$ 922	$ 10	$ 16	$ (5)	$ 943
Restricted cash		12	7	5	24
Accounts and notes receivable, principally customer, net	10	134	12	(3)	153
Accounts and notes receivable affiliated companies	2,210	554	150	(2,914)	
Inventory		237	95		332
Derivative assets		100	32		132
Other current assets	48	166	81	(9)	286
Current assets of discontinued operations	129	95	5	(121)	108
Total current assets	3,319	1,308	398	(3,047)	1,978
Property, Plant and Equipment, net		3,833	769		4,602
Other Assets:					
Other intangibles, net		209	97		306
Notes receivable affiliated companies	1,067	551		(1,618)	
Equity investments of consolidated subsidiaries	1,991	277	18	(2,286)	
Derivative assets		48	5		53
Other long-term assets	41	722	365	(611)	517
Long-term assets of discontinued operations		5			5
Total other assets	3,099	1,812	485	(4,515)	881
Total Assets	$ 6,418	$ 6,953	$ 1,652	$ (7,562)	$ 7,461
LIABILITIES AND EQUITY					
Current Liabilities:					
Current portion of long-term debt	$	$ 405	$	$	$ 405
Accounts payable, principally trade		113	30		143
Accounts and notes payable affiliated companies		2,364	550	(2,914)	

Derivative liabilities		76	76		152
Other current liabilities	10	149	25	(12)	172
Current liabilities of discontinued operations	9	162	8	(121)	58
Total current liabilities	19	3,269	689	(3,047)	930
Other Liabilities:					
Notes payable affiliated companies		1,074	544	(1,618)	
Derivative liabilities			61		61
Other long-term liabilities	572	237	63	(611)	261
Long-term liabilities of discontinued operations	3	11			14
Total other liabilities	575	1,322	668	(2,229)	336
Long-term Debt	1,579	371			1,950
Commitments and Contingencies					
Temporary Equity					
Stock-based Compensation	7				7
Total Stockholders Equity	4,238	1,991	295	(2,286)	4,238
Total Liabilities and Equity	$ 6,418	$ 6,953	$ 1,652	$ (7,562)	$ 7,461

(1) These amounts relate to either (a) eliminations and adjustments recorded in the normal consolidation process or (b) reclassifications recorded as a result of differences in classifications at the subsidiary levels compared to the consolidated level.

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Condensed Consolidating Statements of Cash Flows.

	Nine Months Ended September 30, 2010				
	RRI Energy	Guarantors	Non-Guarantors	Adjustments[1]	Consolidated
			(in millions)		
Cash Flows from Operating Activities:					
Net cash provided by (used in) continuing operations from operating activities	$ 12	$ 274	$ (34)	$	$ 252
Net cash provided by discontinued operations from operating activities	10	24	1		35
Net cash provided by (used in) operating activities	22	298	(33)		287
Cash Flows from Investing Activities:					
Capital expenditures		(45)	(19)		(64)
Investments in, advances to and from and distributions from subsidiaries, net[2]	(165)	424		(259)	
Proceeds from sales of assets, net		8			8
Proceeds from sales (purchases) of emission allowances		7	(7)		
Restricted cash		(4)		5	1
Other, net		4			4
Net cash provided by (used in) continuing operations from investing activities	(165)	394	(26)	(254)	(51)
Net cash used in discontinued operations from investing activities	(3)	(1)	(5)	5	(4)
Net cash provided by (used in) investing activities	(168)	393	(31)	(249)	(55)
Cash Flows from Financing Activities:					
Payments of long-term debt		(400)			(400)
Changes in notes with affiliated companies, net[3]		(311)	52	259	
Proceeds from issuances of stock	2				2

Net cash provided by (used in) continuing operations from financing activities	2	(711)	52	259	(398)
Net cash provided by discontinued operations from financing activities		5		(5)	
Net cash provided by (used in) financing activities	2	(706)	52	254	(398)
Net Change in Cash and Cash Equivalents, Total Operations	(144)	(15)	(12)	5	(166)
Less: Net Change in Cash and Cash Equivalents, Discontinued Operations		(5)	1		(4)
Cash and Cash Equivalents at Beginning of Period, Continuing Operations	922	10	16	(5)	943
Cash and Cash Equivalents at End of Period, Continuing Operations	$ 778	$	$ 3	$	$ 781

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	Nine Months Ended September 30, 2009				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments[1]	Consolidated
Cash Flows from Operating Activities:					
Net cash used in continuing operations from operating activities	$ (115)	$ (88)	$ (72)	$	$ (275)
Net cash provided by discontinued operations from operating activities	134	80	320		534
Net cash provided by (used in) operating activities	19	(8)	248		259
Cash Flows from Investing Activities:					
Capital expenditures		(94)	(64)		(158)
Investments in, advances to and from and distributions from subsidiaries, net[2]	(244)			244	
Proceeds from sales of assets, net		36			36
Proceeds from sales (purchases) of emission allowances		39	(28)		11
Other, net		4			4
Net cash used in continuing operations from investing activities	(244)	(15)	(92)	244	(107)
Net cash provided by (used in) discontinued operations from investing activities	711	6	(418)	15	314
Net cash provided by (used in) investing activities	467	(9)	(510)	259	207
Cash Flows from Financing Activities:					
Payments of long-term debt	(59)				(59)
Changes in notes with affiliated companies, net[3]		96	148	(244)	
Proceeds from issuances of stock	4				4
	(55)	96	148	(244)	(55)

Net cash provided by (used in) continuing operations from financing activities					
Net cash used in discontinued operations from financing activities	(168)	(75)	(3)	(15)	(261)
Net cash provided by (used in) financing activities	(223)	21	145	(259)	(316)
Net Change in Cash and Cash Equivalents, Total Operations	263	4	(117)		150
Less: Net Change in Cash and Cash Equivalents, Discontinued Operations		2	(102)		(100)
Cash and Cash Equivalents at Beginning of Period, Continuing Operations	970		34		1,004
Cash and Cash Equivalents at End of Period, Continuing Operations	$ 1,233	$ 2	$ 19	$	$ 1,254

(1) These amounts relate to either (a) eliminations and adjustments recorded in the normal consolidation process or (b) reclassifications recorded as a result of differences in classifications at the subsidiary levels compared to the consolidated level.

(2) Net investments in, advances to and from and distributions from subsidiaries are classified as investing activities.

(3)

Net changes in notes with affiliated companies are classified as financing activities for subsidiaries of RRI Energy and as investing activities for RRI Energy.

(17) Reportable Segments

Segments. We have four reportable segments: East Coal, East Gas, West and Other. The East Gas, West and Other segments consist primarily of gas plants while the East Coal segment is our coal plants. Each of our generation plants is an operating segment and based on similar economic and other characteristics, we have aggregated them into these four reportable segments. The key earnings drivers we use for internal performance reporting and external communication exhibit how each segment has similar economic characteristics. Key earnings drivers include economic generation (amount of time our plants are economical to operate), commercial capacity factor (generation as a percentage of economic generation), unit margin and other margin. All plants are impacted by supply and demand. Our coal plants (East Coal) are further impacted by gas/coal spreads (the added difference between the price of natural gas and the price of coal). Accordingly, we have aggregated the plants by fuel type and further by geographic region.

In each of our segments, we sell electricity, capacity, ancillary and other energy services from our plants in hour-ahead, day-ahead and forward markets in bilateral and independent system operator markets. All products and services are related to the generation and availability of power, consisting of (a) power generation revenues, (b) capacity revenues and (c) natural gas sales revenues.

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Open Gross Margin. Our segment profitability measure is open gross margin. Open gross margin consists of (a) open energy gross margin and (b) other margin. Open gross margin excludes hedges and other items and unrealized gains/losses on energy derivatives. Open energy gross margin is calculated using the day-ahead and real-time market power sales prices received by the plants less market-based delivered fuel costs. Open energy gross margin is (a)(i) economic generation multiplied by (ii) commercial capacity factor (which equals generation) multiplied by (b) open energy unit margin. Economic generation is estimated generation at 100% plant availability based on an hourly analysis of when it is economical to generate based on the price of power, fuel, emission allowances and variable operating costs. Economic generation can vary depending on the comparison of market prices to our cost of generation. It will decrease if there are fewer hours when market prices exceed the cost of generation. It will increase if there are more hours when market prices exceed the cost of generation. Other margin represents power purchase agreements, capacity payments, ancillary services revenues and selective commercial strategies relating to optimizing our assets.

Items Excluded from Open Gross Margin. We have two primary items that are excluded from our segment measure of open gross margin: (a) hedges and other items and (b) unrealized gains/losses on energy derivatives. Each of these items is included in our consolidated revenues or cost of sales and is described more fully below. We think that excluding these items from our segment profitability measure provides a more meaningful representation of our economic performance in the reporting period and is therefore useful to us and others in facilitating the analysis of our results of operations from one period to another. Hedges and other items and unrealized gains/losses on energy derivatives are also not a function of the operating performance of our generation assets, and excluding their impacts helps isolate the operating performance of our generation assets under prevailing market conditions.

Hedges and Other Items. We may enter selective hedges, including originated transactions, to (a) seek potential value greater than what is available in the spot or day-ahead markets, (b) address operational requirements or (c) seek a specific financial objective. Hedges and other items primarily relate to settlements of power and fuel hedges, long-term natural gas transportation contracts, storage contracts and long-term tolling contracts. They are primarily derived based on methodology consistent with the calculation of open energy gross margin in that a portion of this item represents the difference between the margins calculated using the day-ahead and real-time market power sales prices received by the plants less market-based delivered fuel costs and the actual amounts paid or received during the period. See note 5.

Unrealized Gains/Losses on Energy Derivatives. We use derivative instruments to manage operational or market constraints and to increase the return on our generation assets. We record in our consolidated statement of operations non-cash gains/losses based on current changes in forward commodity prices for derivative instruments receiving mark-to-market accounting treatment which will settle in future periods. We refer to these gains and losses prior to settlement, as well as ineffectiveness on cash flow hedges, as unrealized gains/losses on energy derivatives. In some cases, the underlying transactions being economically hedged receive accrual accounting treatment, resulting in a mismatch of accounting treatments. Since the application of mark-to-market accounting has the effect of pulling forward into current periods non-cash gains/losses relating to and reversing in future delivery periods, analysis of results of operations from one period to another can be difficult. See note 5.

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Financial data for our segments and consolidated are as follows:

	East Coal	East Gas	West	Other	Discontinued Operations	Adjustments and Eliminations	Consolidated
				(in millions)			
Three Months Ended September 30, 2010							
Revenues from external customers[1]	334	$ 151	$ 134	$ 34		$ 44[2]	$ 697[3]
Open energy gross margin	$ 113	$ 27	$ 7	$ 3			$ 150
Other margin	59	58	64	11			192
Open gross margin[4]	$ 172	$ 85	$ 71	$ 14			$ 342[5]
Gains on sales of assets and emission and exchange allowances, net	$	$	$	$		$ 1	$ 1
Long-lived assets impairments	$ 113[6]	$	$	$			$ 113
Three Months Ended September 30, 2009							
Revenues from external customers[1]	$ 219	$ 130	$ 134	$ 28		$ (4)[2]	$ 507[7]
Open energy gross margin	$ 43	$ 12	$ 3	$			$ 58
Other margin	57	55	78	19			209
Open gross margin[4]	$ 100	$ 67	$ 81	$ 19			$ 267[8]
Gains on sales of assets and emission and exchange allowances, net	$	$	$	$		$ 1	$ 1
Nine Months Ended September 30, 2010 (unless otherwise indicated)							
Revenues from external customers[1]	$ 865	$ 416	$ 259	$ 63		$ 99[2]	$ 1,702[9]

Open energy gross margin	$ 269	$ 37	$ 7	$ 3			$ 316
Other margin	158	159	94	25			436
Open gross margin(4)	$ 427	$ 196	$ 101	$ 28			$ 752(10)
Gains on sales of assets and emission and exchange allowances, net	$	$	$ 1	$		$ 1	$ 2
Long-lived assets impairments	$ 361(11)	$	$	$			$ 361
Total assets as of September 30, 2010	$ 3,010(12)	$ 1,271(12)	$ 164(12)	$ 603(12)	$ 44	$ 1,480(13)	$ 6,572
Nine Months Ended September 30, 2009 (unless otherwise indicated)							
Revenues from external customers(1)	$ 687	$ 385	$ 247	$ 75		$ (31)(2)	$ 1,363(14)
Open energy gross margin	$ 178	$ 18	$ 12	$			$ 208
Other margin	132	137	106	46			421
Open gross margin(4)	$ 310	$ 155	$ 118	$ 46			$ 629(15)
Gains on sales of assets and emission and exchange allowances, net	$	$	$ 3	$		$ 18(16)	$ 21
Total assets as of December 31, 2009	$ 3,446(12)	$ 1,316(12)	$ 175(12)	$ 623(12)	$ 113	$ 1,788(13)	$ 7,461

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(1) All revenues are in the United States.

(2) Primarily relates to unrealized gains/losses on energy derivatives, hedges and other items and other revenues not specifically identified to a particular plant or reportable segment.

(3) Includes $392 million in revenues from one counterparty, which represented 56% of our consolidated revenues. This counterparty is included in our East Coal and East Gas segments. As of September 30, 2010, $47 million was outstanding from this counterparty and collected in October 2010.

(4) Represents our segment profitability measure.

(5) Excludes $(1) million and $51 million of hedges and other items and unrealized gains on energy derivatives, respectively, that are included in our consolidated revenues or cost of sales.

(6) Includes $74 million and $39 million related to the Titus and New Castle plants, respectively.

(7) Includes $272 million in revenues from one counterparty, which represented 54% of our consolidated revenues. This counterparty is included in our East Coal and East Gas segments.

(8) Excludes $(34) million and $7 million of hedges and other items and unrealized gains on energy derivatives, respectively, that are included in our consolidated

revenues or cost of sales.

(9) Includes $952 million in revenues from one counterparty, which represented 56% of our consolidated revenues. This counterparty is included in our East Coal and East Gas segments.

(10) Excludes $1 million and $112 million of hedges and other items and unrealized gains on energy derivatives, respectively, that are included in our consolidated revenues or cost of sales.

(11) Includes $193 million, $55 million, $74 million and $39 million related to the Elrama, Niles, Titus and New Castle plants, respectively.

(12) Primarily relates to property, plant and equipment, inventory and emission

allowances. East Coal segment also includes the prepaid RRI Energy Mid-Atlantic Power Holdings, LLC and subsidiaries (REMA) leases of $345 million and $336 million as of September 30, 2010 and December 31, 2009, respectively. Other segment also includes our equity method investment in Sabine Cogen, LP of $19 million as of September 30, 2010 and December 31, 2009.

(13) Represents assets not assigned to a segment. Includes primarily cash and cash equivalents, accounts and notes receivable, derivative assets, margin deposits, certain property, plant and equipment related to corporate assets

and other assets.

(14) Includes $780 million in revenues from one counterparty, which represented 57% of our consolidated revenues. This counterparty is included in our East Coal and East Gas segments.

(15) Excludes $(108) million and $(30) million of hedges and other items and unrealized losses on energy derivatives, respectively, that are included in our consolidated revenues or cost of sales.

(16) Primarily relates to gains on sales of CO_2 exchange allowances and SO_2 emission allowances.

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(in millions)			
Open gross margin for all segments	$ 342	$ 267	$ 752	$ 629
Hedges and other items	(1)	(34)	1	(108)
Unrealized gains (losses) on energy derivatives	51	7	112	(30)
Operation and maintenance	(116)	(115)	(460)	(429)

General and administrative	(21)	(23)	(77)	(80)
Western states litigation and similar settlements			(17)	
Gains on sales of assets and emission and exchange allowances, net	1	1	2	21
Long-lived assets impairments	(113)		(361)	
Depreciation and amortization	(65)	(68)	(196)	(203)
Operating income (loss)	78	35	(244)	(200)
Debt extinguishments gains				1
Interest expense	(39)	(45)	(122)	(137)
Interest income				1
Other, net	2(1)	1(1)	5(1)	1(1)
Income (loss) from continuing operations before income taxes	$ 41	$ (9)	$ (361)	$ (334)

(1) Includes $2 million and $1 million during the three months ended September 30, 2010 and 2009, respectively, and $5 million and $1 million during the nine months ended September 30, 2010 and 2009, respectively, which relates to our equity method investment in Sabine Cogen, LP, which is included in our Other segment.

(18) Discontinued Operations

(a) Retail Energy Segment.

General. In May 2009, we sold our Texas retail business for $363 million in cash, including the value of the net working capital. In December 2009, we sold our Illinois commercial, industrial and governmental/institutional (C&I) contracts and, in December 2008, we sold our C&I contracts in the PJM and New York areas. We will have discontinued operations activity related to these sales through various dates ending in 2013.

Use of Proceeds and Assumptions Related to Debt, Deferred Financing Costs and Interest Expense on Discontinued Operations. As required by our debt agreements, offers to purchase secured notes and PEDFA bonds at par were made with a portion of the net proceeds. We purchased $261 million of the outstanding debt ($169 million of the secured notes and $92 million of the PEDFA bonds) in 2009. These amounts and activity were classified in discontinued operations. We also classified as discontinued operations the related deferred financing costs and interest expense on this debt. We allocated an insignificant amount and $8 million of related interest expense during the three and nine months ended September 30, 2009, respectively, to discontinued operations.

(b) Other Discontinued Operations.

Subsequent to the sale of our New York plants in February 2006, we continue to have (a) insignificant settlements with the independent system operator and (b) various state and local tax issues. In addition, we periodically record amounts for contingent consideration for the 2003 sale of our European energy operations. These amounts are classified as discontinued operations in our results of operations and balance sheets, as applicable.

(c) All Discontinued Operations.

The following summarizes certain financial information of the businesses reported as discontinued operations:

	Retail Energy Segment(1)	New York Plants	European Energy	Total
		(in millions)		
Three Months Ended September 30, 2009				
Revenues	$ 14	$	$	$ 14
Income before income tax expense/benefit	5(2)			5
Nine Months Ended September 30, 2010				
Revenues	$ 1	$	$	$ 1
Income before income tax expense/benefit	10(3)			10
Nine Months Ended September 30, 2009				
Revenues	$ 2,028	$ 2	$	$ 2,030
Income before income tax expense/benefit	1,262(4)(5)	3	9	1,274

(1) The discontinued operations activity during the three months ended September 30, 2010 is insignificant.

(2) Includes $8 million of unrealized gains on energy derivatives.

(3) Includes $6 million of unrealized gains on energy derivatives.

(4) Includes $181 million of unrealized losses on energy derivatives.

(5) Includes $1.2 billion gain on sale (of which $1.1 billion relates to derivatives).

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The following summarizes the assets and liabilities related to our discontinued operations:

	September 30, 2010	December 31, 2009
	(in millions)	
Current Assets:		
Cash and cash equivalents	$	$ 4
Accounts receivable, net	8	6
Derivative assets	17	41
Margin deposits	15	56
Other current assets	1	1
Total current assets	41	108
Other Assets:		
Derivative assets	3	5
Total long-term assets	3	5
Total Assets	$ 44	$ 113
Current Liabilities:		
Accounts payable, principally trade	$ 1	$ 2
Derivative liabilities	13	35
Other current liabilities	1	21
Total current liabilities	15	58
Other Liabilities:		
Derivative liabilities	3	5
Other liabilities	10	9
Total long-term liabilities	13	14
Total Liabilities	$ 28	$ 72

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

The following discussion should be read in conjunction with our Form 10-K. This includes non-GAAP financial measures, which are not standardized; therefore it may not be possible to compare these financial measures with other companies non-GAAP financial measures having the same or similar names. These non-GAAP financial measures, which are discussed further in Consolidated Results of Operations and Liquidity and Capital Resources, reflect an additional way of viewing aspects of our operations and financial position that, when viewed with our GAAP results, may provide a more complete understanding of factors and trends affecting our business. Investors should review our consolidated financial statements and publicly filed reports in their entirety and not rely on any single financial measure.

Business Overview

Strategy. We provide energy, capacity, ancillary and other energy services to wholesale customers in competitive power generation markets in the United States. Our objective is to be the best performing, best positioned generator in competitive electricity markets.

The power generation industry is deeply cyclical and capital intensive. Given the nature of the industry, we think scale and diversity are important long term. Given these beliefs, our strategy is to:

- Maintain a capital structure that positions us to manage through the cycles
- Focus on operational excellence
- Employ flexible plant-specific operating models through the cycle
- Utilize a disciplined capital investment approach
- Create value from industry consolidation

The current market environment is challenging given the pace of economic and power demand recovery, possible legislative and regulatory environmental requirements and the uncertainty in the financial markets. Additionally, current commodity prices and spreads are depressed relative to historical levels. While we think these conditions will improve, the timing is uncertain. Our primary focus is on managing the risks of operating in this current environment. We continue to take actions to navigate the current market challenges, realize value from our existing assets and position us for the longer term market recovery, while maximizing cash flow and building ample liquidity. Some of these actions include:

- Focusing on operating efficiency and effectiveness
- Implementing flexible plant-specific operating models
- Implementing a modest hedging program to achieve a high probability of achieving free cash flow breakeven or better even if market conditions deteriorate further

We are regularly assessing the impact on our business of a wide variety of economic and commodity price scenarios, and think we have the ability to operate through an extended downturn.

Key Earnings Drivers. Our financial results are significantly impacted by supply and demand fundamentals in the regions in which we operate as well as the spread between gas and coal prices. Plants with lower costs dispatch ahead of higher cost plants to meet demand, with the price of electricity being set by the last plant dispatched.

The specific factors that drive our margins include the prices of power, capacity, natural gas, coal and fuel oil, the cost of emission allowances and transmission, as well as weather and economic factors, many of which are volatile. Our ability to control these factors is limited, and in most instances, the factors are beyond our control. We have the most control over the percentage of time that our plants are available to run when it is economical for them to do so (commercial capacity factor). Our key earnings drivers and various factors that affect these earnings drivers include:

Economic generation (amount of time our plants are economical to operate)

Supply and demand fundamentals

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Plant fuel type and efficiency

Absolute and relative cost of fuels used in power generation

Commercial capacity factor (generation as a percentage of economic generation)

Operations effectiveness

Maintenance practices

Planned and unplanned outages

Unit margin

Supply and demand fundamentals

Commodity prices and spreads

Plant fuel type and efficiency

Other margin (primarily capacity sales)

Supply and demand fundamentals

Power purchase agreements sold to others

Ancillary services

Equipment performance

Costs

Operating efficiency

Maintenance practices

Generation asset fuel type

Planned and unplanned outages

Environmental compliance

Hedges

Hedging strategy

Volumes

Commodity prices

Effectiveness

Effectiveness and Efficiency Measures. Consistent with our flexible plant-specific operating model, our objective is to operate each plant to capture the maximum value at the lowest economical cost over time. This year we began using total margin capture factor to measure our effectiveness of achieving this objective. Total margin capture factor is calculated by dividing open gross margin generated by the plants by the total available open gross margin assuming 100% availability. Likewise, we began measuring our efficiency of capturing margin utilizing total controllable costs per MWh generated and total controllable costs per MW of generation capacity. These costs metrics include operation and maintenance expense (excluding the REMA lease expense and severance expense) and general and administrative expense (excluding severance expense and merger-related costs) as well as maintenance capital expenditures. See these measures below under Consolidated Results of Operations.

Recent Events

In this section, we present recent and potential events that have impacted or could in the future impact our results of operations, financial condition or liquidity. In addition to the events described below, a number of other factors could affect our future results of operations, financial condition or liquidity, including changes in natural gas prices, plant availability, weather and other factors. See Risk Factors in Item 1A of this report and our Form 10-K.

Proposed Merger with Mirant.

Merger. On April 11, 2010, we entered into a definitive merger agreement in which the companies would combine in a stock-for-stock transaction. We have formed a new wholly-owned subsidiary that will merge with and into Mirant upon closing. As a result, Mirant will be a wholly-owned subsidiary of RRI Energy. We anticipate completing the merger before the end of 2010.

Upon closing the merger, each issued and outstanding share of Mirant common stock will convert into the right to receive 2.835 shares of our common stock. Mirant stock options and other equity awards will convert upon completion of the merger into vested stock options and equity awards with respect to our common stock, after giving effect to the exchange ratio. The exchange ratio is fixed but subject to adjustment for a proposed reverse stock split.

Status of Merger Conditions. We and Mirant have satisfied many of the conditions to completion of the merger, including:

- stockholder approval of the proposals related to the merger on October 25, 2010;
- FERC approval of the merger by order dated August 2, 2010; and
- receipt of NYPSC s order dated July 20, 2010, declaring that it will not further review the merger.

The primary remaining condition to closing the merger is completion by the DOJ of its review of the merger. On June 14, 2010, we and Mirant filed notification of the proposed transaction with the Federal Trade Commission and the DOJ under the HSR Act. On July 15, 2010, we received a request for additional information from the DOJ. The additional information requested is to assist the DOJ on their review of the merger.

As further described below, on September 20, 2010, RRI Energy and Mirant entered into agreements which provide for the companies to borrow $1.925 billion upon closing of the proposed merger. Upon such closing, the proceeds of the financings and cash on hand will be used to:

- discharge the RRI Energy senior secured notes due 2014 and Mirant North America (MNA) senior unsecured notes due 2013;
- defease the RRI Energy PEDFA 6.75% bonds due 2036;
- repay the MNA senior secured term loan maturing in 2013; and
- pay related fees and expenses, including accrued interest.

In addition, RRI Energy entered into a revolving credit facility to be available upon the closing of the merger. Upon their completion, the financings, along with the availability of the revolving credit facility, satisfy the financing condition in the merger agreement.

Senior Secured Term Loan Facility and Revolving Credit Facility. On September 20, 2010, RRI Energy entered into a credit agreement. From and after the closing date of the merger, Mirant Americas, Inc. will be party to the credit agreement. The credit agreement includes new senior secured credit facilities, with RRI Energy and Mirant Americas, Inc. as borrowers, consisting of:

- $700 million seven-year senior secured term loan facility, to be funded at the closing of the merger, with a rate of LIBOR + 4.25% (with a LIBOR floor of 1.75%); and
- $788 million five-year senior secured revolving credit facility, available at the closing of the merger, with an undrawn rate of 0.75% and a draw rate of LIBOR + 3.50%.

We refer to the new revolving credit facility and new term loan facility collectively as the new credit facility. The new credit facility is expected to close and fund on the closing date of the merger and such closing and funding is subject to satisfaction of various conditions precedent, including:

- the companies receiving at least $1.9 billion in gross cash proceeds from the senior unsecured notes offering described below (or other issuance of senior unsecured notes) and borrowings under the new term loan facility (without giving effect to original issue discount); and

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the closing of the new credit facility having occurred on or prior to December 31, 2010; provided, however, that the deadline for the closing for the new term loan facility and for the new revolving commitments of each consenting revolving lender shall be extended to March 31, 2011 if revolving lenders holding not less than $750 million of revolving commitments consent to such extension.

Upon the closing of the new credit facility, our obligations under the new credit facility will be guaranteed by certain of our existing and future direct and indirect subsidiaries; provided, however, that Mirant Americas Generation s subsidiaries (other than Mirant Mid-Atlantic and Mirant Energy Trading and their subsidiaries) will provide guarantees only to the extent permitted under the indenture for the senior notes of Mirant Americas Generation. In addition, upon closing of the new credit facility, the obligations and guarantees under the new credit facility will be secured by a first priority security interest in substantially all of our assets, subject to exceptions set forth in the new credit facility.

Senior Unsecured Notes. On September 20, 2010, RRI Energy entered into a purchase agreement along with Mirant, GenOn Escrow Corp. (GenOn Escrow), a newly formed Delaware subsidiary of Mirant, related to two series of senior unsecured notes as follows:

$675 million of 9.5% senior unsecured notes due 2018 to be initially issued by GenOn Escrow; and

$550 million of 9.875% senior unsecured notes due 2020 to be initially issued by GenOn Escrow.

The senior unsecured notes were issued on October 4, 2010 by GenOn Escrow and the funds were deposited into a segregated escrow account pending completion of the merger. Upon completion of the merger, GenOn Escrow will merge with and into RRI Energy and RRI Energy will assume all of GenOn Escrow s obligations under the notes and the related indenture and the funds held in escrow will be released to us.

Impairments of Long-Lived Assets. In September and March 2010, we evaluated our plants including the related intangible assets for potential impairments. We determined that four plants undiscounted cash flows did not exceed the carrying value of the net property, plant and equipment (Titus and New Castle in the third quarter and Elrama and Niles in the first quarter). Thus, we estimated each plant s fair value and determined we incurred pre-tax impairment charges of $113 million during the third quarter and $248 million during the first quarter. See note 4 to our consolidated financial statements in our Form 10-K, note 7 to our interim financial statements and New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates Critical Accounting Estimates.

Environmental Matters. In June 2010, the EPA finalized the revised primary national ambient air quality standard for SO_2. The EPA expects to determine nonattainment areas using the revised standard by mid-2012, with attainment required five years thereafter. It is possible that additional SO_2 emission control measures may be necessary if our plants are in or near nonattainment areas. In addition, in July 2010, the EPA proposed the Transport Rule to replace the Clean Air Interstate Rule (CAIR) and plans to finalize this rule in 2011. Each of the Transport Rule s three alternative proposals, if finalized, would impose more stringent NOx and SO_2 emission reductions than were required under CAIR, in particular starting in 2014. The EPA s preferred alternative includes a cap and trade approach and includes incentives to retire older, uncontrolled coal plants. In June 2010, the EPA finalized the Greenhouse Gas Tailoring rule. As a result, we could be subject to new source review permitting requirements (determined on a case by case basis) for greenhouse gas emissions beginning in 2011 with respect to investments, if any, to modify our plants.

The effect of more stringent environmental rules, including those described above, if implemented, is that many older coal plants without emission controls, including some of ours, will likely be retired. Combined with compressed spreads between gas and coal prices, we believe the amount of retirements would increase. We also expect to see an increase in investments on emissions controls, potentially including some of our fleet.

However, any such retirements could contribute to improving supply and demand fundamentals for the remaining fleet and higher capacity and energy prices. Any resulting increased demand for gas could increase the spread between gas and coal prices, which would also benefit the remaining coal fleet.

The New Jersey Department of Environmental Protection is evaluating proposed changes to its high electricity demand days regulations and may defer for two years, in part or in whole, requirements for reduction in NO_x emissions from combustion turbines. If we elect to install these controls, we could incur capital expenditures of up to approximately $190 million primarily during 2014 to 2017.

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To comply with our permitting conditions and subject to market conditions, we could be required to install a cooling tower at one or more of our Shawville, Pennsylvania units by late 2014. If we elect to install controls, we could invest approximately $80 million, primarily during 2012 to 2014.

The impact on our business of these regulations and pending regulations and whether we make any potential investments remains uncertain. As environmental regulations evolve, we will continue to assess the recoverability of our long-lived assets (property, plant and equipment and intangible assets). See Business Environmental Matters in Item 1, Risk Factors in Item 1A and Management s Discussion and Analysis of Financial Condition and Results of Operations Business Overview Pending Environmental Matters in Item 7 of our Form 10-K.

Cheswick Scrubber Operation. After initial operation of the scrubber at our Cheswick facility, we have discovered corrosion in the absorber vessel during inspections in an ongoing planned outage. We are conducting a review of the causes and nature of the corrosion and developing a corrective action plan. We believe that the costs of any repairs would be covered under the warranty for the scrubber. If the ultimate costs of the repairs are not covered by warranty or insurance, we could incur additional capital expenditures to repair the equipment. In addition, earnings from the plant will be further impacted depending on the duration of the extension of the planned outage.

Financial Reform Legislation. President Obama signed into law financial reform legislation that will impose new regulations on over-the-counter derivatives, which includes requirements for clearing swaps through a derivatives clearing organization. The majority of our existing hedges have been cleared through a derivatives clearing organization. Many requirements of the legislation will be clarified in regulations yet to be issued.

RPM Auctions. In 2010, we have captured approximately $450 million in additional minimum sales commitments for future periods. These commitments were obtained in the PJM Market s reliability pricing model (RPM) auctions of which approximately $400 million represent future capacity revenues for 2013 and 2014.

Consolidated Results of Operations

Non-GAAP Performance Measures. In analyzing and planning for our business, we supplement our use of GAAP financial measures with some non-GAAP financial measures. We present open gross margin, our segment profitability measure, open energy gross margin and other margin on a consolidated basis. We also present earnings (loss) before interest, taxes, depreciation and amortization (EBITDA), adjusted EBITDA and Open EBITDA, which we consider performance measures rather than liquidity measures. We think the measures of total controllable costs per MWh generated and total controllable costs per MW of generation capacity provide meaningful measures of our efficiency, which, beginning in 2010, we use to communicate with others about earnings outlook and results. We have metrics on both a per-MWh and a per-MW capacity basis because we have plants that primarily earned capacity revenues and others that also produce material amounts of energy revenue. We use these non-GAAP financial measures in communications with investors, analysts, rating agencies, banks and other parties. We think these non-GAAP financial measures provide meaningful representations of our consolidated operating performance and are useful to us and others in facilitating the analysis of our results of operations from one period to another. In addition, many analysts and investors use EBITDA to evaluate financial performance. The adjustments to arrive at these non-GAAP financial measures are described below. Management thinks (a) these adjusted items are not representative of our ongoing business operations, (b) excluding them provides a more meaningful representation of our results of operations and (c) it is useful to us and others to make these adjustments to facilitate the analysis of our results of operations from one period to another.

Three Months Ended September 30, 2010 Compared to Three Months Ended September 30, 2009

Our income (loss) from continuing operations before income taxes for the three months ended September 30, 2010 compared to the same period in 2009 increased by $50 million primarily as a result of (a) $75 million increase in open gross margin primarily from higher unit margins related to improved economic conditions and improved generation related to warmer weather in our East Coal segment, partially offset by higher outages, (b) $44 million increase in unrealized gains/losses on energy derivatives and (c) $33 million increase in hedges and other items primarily from improved coal hedge results in our East Coal segment, partially offset by decline in hedges of generation. These items were partially offset by $113 million long-lived assets impairments recorded in 2010.

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	Three Months Ended September 30, 2010	2009	Change
		(in millions)	
East coal open gross margin[1]	$ 172	$ 100	$ 72
East gas open gross margin[1]	85	67	18
West open gross margin[1]	71	81	(10)
Other open gross margin[1]	14	19	(5)
Total[2]	342	267	75
Operation and maintenance, excluding severance[3][4]	(116)	(114)	(2)
General and administrative, excluding severance and merger-related costs[4][5]	(16)	(21)	5
Other, net	2	1	1
Open EBITDA[2]	212	133	79
Hedges and other items[6][7]	(1)	(34)	33
Gains on sales of assets and emission and exchange allowances, net[8]	1	1	
Adjusted EBITDA[2]	212	100	112
Unrealized gains on energy derivatives[7][9]	51	7	44
Severance[10]		(3)	3
Merger-related costs[11]	(5)		(5)
Long-lived assets impairments[12]	(113)		(113)
EBITDA[2]	145	104	41
Depreciation and amortization	(65)	(68)	3
Interest expense, net	(39)	(45)	6
Income (loss) from continuing operations before income taxes	41	(9)	50
Income tax expense	(18)	(10)	(8)
Income (loss) from continuing operations	23	(19)	42
Income from discontinued operations		4	(4)
Net income (loss)	$ 23	$ (15)	$ 38

(1) Represents our segment profitability measure.

(2) The most directly comparable GAAP financial measure is income (loss) from continuing operations before income taxes.

(3) The most directly comparable GAAP financial measure is operation and maintenance expense.

(4) We exclude severance charges incurred in connection with (a) repositioning the company in connection with the sale of our retail business and (b) implementing our plant-specific operating model. We also exclude merger-related costs, including financial advisory fees, legal costs, stock-based compensation expense related to the modification of our stock options and other merger-related expenses. We think this adjusted measure helps to provide a meaningful representation of our ongoing operating performance, which we use to communicate with others about earnings outlook and results.

(5) The most directly comparable GAAP financial measure is general and administrative expense.

(6) Described below under Hedges and Other Items.

(7) Hedges and other items and unrealized gains/losses on energy derivatives are not a function of the operating performance of our generation assets, and excluding their impacts helps isolate the operating performance of our generation assets under prevailing market conditions.

(8) We periodically sell emission and exchange allowances inventory in excess of our forward power sales commitments if the price is above our view of their value. We think that excluding the gains from such sales, as well as gains and losses on asset sales, is useful because these gains/losses are not directly tied to the operating performance of our generation assets, and excluding them helps to isolate the operating performance of our generation assets under prevailing market conditions.

(9) Described below under Unrealized Gains (Losses) on Energy Derivatives.

(10) Includes severance classified in operation and maintenance and general and administrative expenses.

(11) Includes merger-related costs classified in general and administrative expense.

(12) Impairment charges are related to our Titus and New Castle long-lived assets totaling $113 million. See note 7 to our interim financial statements.

	Three Months Ended September 30,		
	2010	**2009**	**Change**
Diluted Earnings (Loss) per Share			
Income (loss) from continuing operations	$ 0.06	$ (0.05)	$ 0.11
Income from discontinued operations		0.01	(0.01)
Net income (loss)	$ 0.06	$ (0.04)	$ 0.10

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Operational and Financial Data.

	Generation (GWh) (1)		Open Energy Unit Margin ($/MWh) (2)		Total Margin Capture Factor(3)	
	Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,	
Segment	2010	2009	2010	2009	2010	2009
East Coal	5,513.9	4,943.5	$ 20.49	$ 8.70	89.4%	90.5%
East Gas	904.3	1,004.1	29.86	11.95	92.2	95.1
West	168.3	272.7	41.59	11.00	97.9	99.2
Other	356.6	11.6	8.41		98.0	NM(4)
Total	6,943.1	6,231.9	$ 21.60	$ 9.31	92.1%	94.8%

(1) Excludes generation related to power purchase agreements.

(2) Represents open energy gross margin divided by generation. See Open Gross Margin below.

(3) Total margin capture factor is calculated by dividing open gross margin generated by the plants by the total available open gross margin, assuming 100% availability. See Open Gross Margin below.

Revenues.

	Three Months Ended September 30,		
	2010	2009	Change
		(in millions)	
Revenues	$ 647	$ 532	$ 115(1)
Unrealized gains (losses) on energy derivatives	50	(25)	75(2)
Total revenues	$ 697	$ 507	$ 190

(1) Increase primarily as a result of (a) higher power and natural gas sales prices and (b) an increase in power sales volumes. These increases were

partially offset by lower natural gas sales volumes.

(2) See footnote 1 under Unrealized Gains (Losses) on Energy Derivatives.

Cost of Sales.

	Three Months Ended September 30,		
	2010	2009	Change
	(in millions)		
Cost of sales	$ 306	$ 299	$ 7(1)
Unrealized gains on energy derivatives	(1)	(32)	31(2)
Total cost of sales	$ 305	$ 267	$ 38

(1) Increase primarily as a result of (a) higher prices paid for natural gas and (b) higher coal volumes purchased. These increases were partially offset by (a) lower prices paid for coal and (b) lower natural gas volumes purchased.

(2) See footnote 1 under Unrealized Gains (Losses) on Energy Derivatives.

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Open Gross Margin. Our segment profitability measure is open gross margin. Open gross margin consists of (a) open energy gross margin and (b) other margin. Open gross margin excludes hedges and other items and unrealized gains/losses on energy derivatives. Open energy gross margin is calculated using the day-ahead and real-time market power sales prices received by the plants less market-based delivered fuel costs. Open energy gross margin is (a)(i) economic generation multiplied by (ii) commercial capacity factor (which equals generation) multiplied by (b) open energy unit margin. Economic generation is estimated generation at 100% plant availability based on an hourly analysis of when it is economical to generate based on the price of power, fuel, emission allowances and variable operating costs. Economic generation can vary depending on the comparison of market prices to our cost of generation. It will decrease if there are fewer hours when market prices exceed the cost of generation. It will increase if there are more hours when market prices exceed the cost of generation. Other margin represents power purchase agreements, capacity payments, ancillary services revenues and selective commercial strategies relating to optimizing our assets.

	Three Months Ended September 30,		
	2010	2009	Change
		(in millions)	
East Coal			
Open energy gross margin	$ 113	$ 43	$ 70(1)
Other margin	59	57	2
Open gross margin	$ 172	$ 100	$ 72
East Gas			
Open energy gross margin	$ 27	$ 12	$ 15(2)
Other margin	58	55	3
Open gross margin	$ 85	$ 67	$ 18
West			
Open energy gross margin	$ 7	$ 3	$ 4
Other margin	64	78	(14)(3)
Open gross margin	$ 71	$ 81	$ (10)
Other			
Open energy gross margin	$ 3	$	$ 3
Other margin	11	19	(8)
Open gross margin	$ 14	$ 19	$ (5)
Total			
Open energy gross margin(4)	$ 150	$ 58	$ 92
Other margin(4)	192	209	(17)
Open gross margin(4)	$ 342	$ 267	$ 75

(1) Increase primarily as a result of higher unit margins (higher power prices partially offset by higher fuel costs) and improved generation driven by increased demand related to weather. This increase is partially offset by higher outages.

(2) Increase primarily as a result of higher unit margins (higher power prices partially offset by higher fuel costs).

(3) Decrease primarily as a result of a decline in capacity payments.

(4) The most directly comparable GAAP financial measure is income (loss) from continuing operations before income taxes. See Non-GAAP Performance Measures.

Included in revenues or cost of sales are two items (a) hedges and other items and (b) unrealized gains/losses on energy derivatives that are not included in open gross margin. See notes 4, 5 and 17 to our interim financial statements for further discussion. The analyses of these items are included below.

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Hedges and Other Items. We may enter selective hedges, including originated transactions, to (a) seek potential value greater than what is available in the spot or day-ahead markets, (b) address operational requirements or (c) seek a specific financial objective. Hedges and other items primarily relate to settlements of power and fuel hedges, long-term natural gas transportation contracts, storage contracts and long-term tolling contracts. They are primarily derived based on methodology consistent with the calculation of open energy gross margin in that a portion of this item represents the difference between the margins calculated using the day-ahead and real-time market power sales prices received by the plants less market-based delivered fuel costs and the actual amounts paid or received during the period.

	Three Months Ended September 30,		
	2010	2009	Change
		(in millions)	
Power	$ (5)	$ 20	$ (25)(1)
Fuel	3	(51)	54(2)
Tolling/other	1	(3)	4
Hedges and other items income (loss)	$ (1)	$ (34)	$ 33

(1) Decrease primarily as a result of decline in hedges of generation.

(2) Increase primarily as a result of (a) $33 million driven by improved results of fuel hedges in 2010 as compared to 2009 and (b) $22 million reduction in lower market valuation adjustments to fuel inventory in our East Coal segment.

Unrealized Gains (Losses) on Energy Derivatives. We use derivative instruments to manage operational or market constraints and to increase the return on our generation assets. We record in our consolidated statement of operations non-cash gains/losses based on current changes in forward commodity prices for derivative instruments receiving mark-to-market accounting treatment which will settle in future periods. We refer to these gains and losses prior to settlement, as well as ineffectiveness on cash flow hedges, as unrealized gains/losses on energy derivatives. In some cases, the underlying transactions being economically hedged receive accrual accounting treatment, resulting in a mismatch of accounting treatments. Since the application of mark-to-market accounting has the effect of pulling forward into current periods non-cash gains/losses relating to and reversing in future delivery periods, analysis of results of operations from one period to another can be difficult.

	Three Months Ended September 30, 2010	2009	Change
	(in millions)		
Revenues unrealized	$ 50	$ (25)	$ 75
Cost of sales unrealized	1	32	(31)
Net unrealized gains on energy derivatives	$ 51	$ 7	$ 44(1)

(1) Net change primarily as a result of $65 million in gains from changes in prices on our energy derivatives marked to market, partially offset by $21 million in losses driven by the reversal of previously recognized unrealized gains on energy derivatives which settled during the period.

Operation and Maintenance.

	Three Months Ended September 30, 2010	2009	Change
	(in millions)		
Plant operation and maintenance	$ 89	$ 79	$ 10(1)
REMA leases	15	15	
Taxes other than income and insurance	7	8	(1)
Information Technology, Risk and other salaries and benefits	4	4	
Commercial Operations	3	4	(1)

Severance		1	(1)
Other, net	(2)	4	(6)
Operation and maintenance	$ 116	$ 115	$ 1

(1) Increase primarily as a result of $11 million increase in planned outages and projects spending primarily in our East Coal and West segments.

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General and Administrative.

	Three Months Ended September 30,		
	2010	2009	Change
		(in millions)	
Salaries and benefits	$ 12	$ 11	$ 1
Merger-related costs	5		5
Professional fees, contract services and information systems maintenance	3	4	(1)
Severance		2	(2)
Other, net	1	6	(5)
General and administrative	$ 21	$ 23	$ (2)

Efficiency Measures   Total Controllable Costs.

	Three Months Ended September 30,		
	2010	2009	Change
	(dollars in millions, except per MWh and per MW data)		
Operation and maintenance, excluding severance(1)	$ 116	$ 114	$ 2
REMA lease expense	(15)	(15)	
General and administrative, excluding severance and merger-related costs(1)	16	21	(5)
Maintenance capital expenditures	4	10	(6)
Total Controllable Costs	$ 121	$ 130	$ (9)
TWh generation	6.9	6.2	0.7
Total Controllable Costs/MWh	$ 18	$ 21	$ (3)
MW capacity (2)	14,586	14,563	23
Total Controllable Costs ($ thousands)/MW capacity	$ 8.3	$ 8.9	$ (0.6)

(1) Excludes (a) severance charges incurred in connection with (i) repositioning the company in connection with

the sale of our retail business and (ii) implementing our plant-specific operating model, classified in operation and maintenance and general and administrative and (b) merger-related costs classified in general and administrative. Merger-related costs include financial advisory fees, legal costs, stock-based compensation expense related to the modification of our stock options and other merger-related expenses.

(2) MW capacity changed from September 30, 2009 to September 30, 2010 as a result of MW re-ratings that occurred during the fourth quarter of 2009 and third quarter of 2010.

Total Controllable Costs Reconciliation. There is no single directly comparable GAAP financial measure that reflects controllable costs; however, these costs metrics are calculated by aggregating operation and maintenance expense, general and administrative expense as well as capital expenditures. We exclude from operation and maintenance expense and general and administrative expense severance charges incurred in connection with (a) repositioning the company in connection with the sale of our retail business and (b) implementing our plant-specific operating model. We exclude from general and administrative expense merger-related costs, including financial advisory fees, legal costs, stock-based compensation expense related to the modification of our stock options and other merger-related expenses. We also exclude (a) the REMA lease expense because of its financing nature and (b) capital expenditures other than maintenance because maintenance capital expenditures are more routine and closely related to current year operations.

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	Three Months Ended September 30, 2010	2009	Change
	(dollars in millions, except per MWh and per MW data)		
Operation and maintenance (O&M)	$ 116	$ 115	$ 1
General and administrative (G&A)	21	23	(2)
Capital expenditures	14	43	(29)
Total operation and maintenance, general and administrative and capital expenditures	$ 151	$ 181	$ (30)
Total Controllable Costs	$ 121	$ 130	$ (9)
REMA lease expense in operation and maintenance	15	15	
Severance included in operation and maintenance		1	(1)
Severance included in general and administrative		2	(2)
Merger-related costs included in general and administrative	5		5
Environmental capital expenditures	10	25	(15)
Capitalized interest		8	(8)
Total operation and maintenance, general and administrative and capital expenditures	$ 151	$ 181	$ (30)
TWh generation	6.9	6.2	0.7
Total O&M, G&A and capital expenditure/MWh	$ 22	$ 29	$ (7)
MW capacity (1)	14,586	14,563	23
Total O&M, G&A and capital expenditures ($ thousands)/MW capacity	$ 10.4	$ 12.4	$ (2.0)

(1) MW capacity changed from September 30, 2009 to September 30, 2010 as a result of MW re-ratings that occurred during the fourth

quarter of 2009
and the third
quarter of 2010.

Gains on Sales of Assets and Emission and Exchange Allowances, Net. This amount did not change significantly.

Long-lived Assets Impairments. See note 7 to our interim financial statements.

Depreciation and Amortization.

	Three Months Ended September 30,		
	2010	**2009**	**Change**
		(in millions)	
Depreciation on plants	$ 55	$ 55	$
Other, net depreciation	3	4	(1)
Depreciation	58	59	(1)
Amortization of emission allowances	6	8	(2)
Other, net amortization	1	1	
Amortization	7	9	(2)
Depreciation and amortization	$ 65	$ 68	$ (3)

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Debt Extinguishments Losses. This represents losses on extinguishments of our senior secured notes.
Interest Expense.

	Three Months Ended September 30,		
	2010	2009	Change
	(in millions)		
Fixed-rate debt	$ 37	$ 52	$ (15)[(1)]
Deferred financing costs	2	2	
Amortization of fair value adjustment of acquired debt		(3)	3
Capitalized interest		(8)[(2)]	8
Other, net		2	(2)
Interest expense	$ 39	$ 45	$ (6)

(1) Decrease as a result of a reduction in fixed-rate debt primarily due to $400 million in payments of the Orion Power Holdings, Inc. senior notes in May 2010.

(2) Relates primarily to environmental capital expenditures for SO_2 emission reductions at our Cheswick and Keystone plants.

Other, Net. This amount did not change significantly.
Income Tax Expense (Benefit). See note 11 to our interim financial statements. A reconciliation of the federal statutory income tax rate to the effective income tax rate is:

	Three Months Ended September 30,	
	2010	2009
Federal statutory rate	35%	(35)%
Additions (reductions) resulting from:		

Federal valuation allowance	31(1)	134(2)
State income taxes, net of federal income taxes	5(3)	(20)(4)
Other	(25)	30(5)(6)
Effective rate	46%	109%

(1) Of this percentage, $13 million (31%) relates to additional valuation allowance.

(2) Of this percentage, $12 million (134%) relates to additional valuation allowance.

(3) Of this percentage, $4 million (11%) relates to additional valuation allowance.

(4) Of this percentage, $(2) million (20%) relates to a reduction in valuation allowance.

(5) Of this percentage, $3 million (34%) relates to the disallowance of net operating loss carryforward.

(6) Includes $15 million of a

valuation allowance release offset by $15 million of expired foreign net operating loss carryforwards.

Income from Discontinued Operations. See note 18 to our interim financial statements.

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Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009

Our loss from continuing operations before income taxes for the nine months ended September 30, 2010 compared to the same period in 2009 increased by $27 million as a result of (a) $361 million long-lived assets impairments recorded in 2010, (b) $34 million increase in operation and maintenance expense, excluding severance, primarily from planned outages in our East Coal and West segments and (c) an estimated $17 million charge for Western states litigation and similar settlements recorded in 2010. These items were partially offset by (a) $142 million net change in unrealized gains/losses on energy derivatives, (b) $123 million increase in open gross margin from higher unit margins related to improved economic conditions and improved generation, partially offset by higher outages in our East Coal segment and RPM capacity payments in our East Coal and East Gas segments and (c) $109 million increase in hedges and other items primarily from improved coal hedge results in our East Coal segment, partially offset by decline in hedges of generation.

	Nine Months Ended September 30,		
	2010	2009	Change
		(in millions)	
East coal open gross margin[1]	$ 427	$ 310	$ 117
East gas open gross margin[1]	196	155	41
West open gross margin[1]	101	118	(17)
Other open gross margin[1]	28	46	(18)
Total[2]	752	629	123
Operation and maintenance, excluding severance[3][4]	(458)	(424)	(34)
General and administrative, excluding severance and merger-related costs[4][5]	(58)	(77)	19
Other, net	5	1	4
Open EBITDA[2]	241	129	112
Hedges and other items[6][7]	1	(108)	109
Gains on sales of assets and emission and exchange allowances, net[8]	2	21	(19)
Adjusted EBITDA[2]	244	42	202
Unrealized gains (losses) on energy derivatives[7][9]	112	(30)	142
Western states litigation and similar settlements[10]	(17)		(17)
Severance[11]	(2)	(8)	6
Merger-related costs[12]	(19)		(19)
Long-lived assets impairments[13]	(361)		(361)
Debt extinguishments gains[14]		1	(1)
EBITDA[2]	(43)	5	(48)
Depreciation and amortization	(196)	(203)	7
Interest expense, net	(122)	(136)	14
Loss from continuing operations before income taxes	(361)	(334)	(27)
Income tax (expense) benefit	(69)	106	(175)

Loss from continuing operations		(430)		(228)		(202)
Income from discontinued operations		4		865		(861)
Net income (loss)	$	(426)	$	637	$	(1,063)

(1) Represents our segment profitability measure.

(2) The most directly comparable GAAP financial measure is income (loss) from continuing operations before income taxes.

(3) The most directly comparable GAAP financial measure is operation and maintenance expense.

(4) We exclude severance charges incurred in connection with (a) repositioning the company in connection with the sale of our retail business and (b) implementing our plant-specific operating model. We also exclude merger-related costs, including financial advisory fees, legal costs, stock-based compensation

expense related to the modification of our stock options and other merger-related expenses. We think this adjusted measure helps to provide a meaningful representation of our ongoing operating performance, which we use to communicate with others about earnings outlook and results.

(5) The most directly comparable GAAP financial measure is general and administrative expense.

(6) Described below under Hedges and Other Items.

(7) Hedges and other items and unrealized gains/losses on energy derivatives are not a function of the operating performance of our generation assets, and excluding their impacts helps isolate the operating performance of our generation assets under prevailing market

conditions.

(8) We periodically sell emission and exchange allowances inventory in excess of our forward power sales commitments if the price is above our view of their value. We think that excluding the gains from such sales, as well as gains and losses on asset sales, is useful because these gains/losses are not directly tied to the operating performance of our generation assets, and excluding them helps to isolate the operating performance of our generation assets under prevailing market conditions.

(9) Described below under Unrealized Gains (Losses) on Energy Derivatives.

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(10) We exclude charges related to settlement of actions in our legacy Western states and similar matters. See note 12 to our interim financial statements.

(11) Includes severance classified in operation and maintenance and general and administrative expenses.

(12) Includes merger-related costs classified in general and administrative expense.

(13) Impairment charges are related to our Elrama, Niles, Titus and New Castle long-lived assets totaling $361 million. See note 7 to our interim financial statements.

(14) We exclude charges incurred in connection with refinance or purchase of debt, including

the accelerated amortization of deferred financing costs, because these charges result from our efforts to increase our financial flexibility and are not a function of our operating performance.

	Nine Months Ended September 30, 2010	2009	Change
Diluted Earnings (Loss) per Share			
Loss from continuing operations	$ (1.22)	$ (0.65)	$ (0.57)
Income from discontinued operations	0.01	2.46	(2.45)
Net income (loss)	$ (1.21)	$ 1.81	$ (3.02)

Operational and Financial Data.

Segment	Generation (GWh) Nine Months Ended September 30, 2010	2009	Open Energy Unit Margin ($/MWh) Nine Months Ended September 30, 2010	2009	Total Margin Capture Factor Nine Months Ended September 30, 2010	2009
East Coal	15,592.3	14,711.6	$ 17.25	$ 12.10	82.8%	84.5%
East Gas	1,691.7	1,638.4	21.87	10.99	92.0	93.4
West	194.8	497.7	35.93	24.11	94.3	95.1
Other	394.0	73.9	7.61		99.0	NM(1)
Total	17,872.8	16,921.6	$ 17.68	$ 12.29	87.0%	89.5%

(1) NM is not meaningful.

Revenues.

	Nine Months Ended September 30, 2010	2009	Change
	(in millions)		

Revenues	$	1,603	$	1,414	$	189(1)
Unrealized gains (losses) on energy derivatives		99		(51)		150(2)
Total revenues	$	1,702	$	1,363	$	339

(1) Increase primarily as a result of (a) higher power and natural gas sales prices, (b) an increase in power sales volumes and (c) higher capacity payments. These increases were partially offset by lower natural gas sales volumes.

(2) See footnote 1 under Unrealized Gains (Losses) on Energy Derivatives.

Cost of Sales.

	Nine Months Ended September 30,					
	2010		2009		Change	
			(in millions)			
Cost of sales	$	850	$	893	$	(43)(1)
Unrealized gains on energy derivatives		(13)		(21)		8(2)
Total cost of sales	$	837	$	872	$	(35)

(1) Decrease primarily as a result of (a) lower prices paid for coal, (b) lower natural gas

volumes purchased and (c) additional costs in 2009 to reduce fixed price coal commitments for future periods. These decreases were partially offset by (a) higher prices paid for natural gas and (b) an increase in coal volumes purchased.

(2) See footnote 1 under Unrealized Gains (Losses) on Energy Derivatives.

Open Gross Margin.

	Nine Months Ended September 30, 2010	2009	Change
	(in millions)		
East Coal			
Open energy gross margin	$ 269	$ 178	$ 91(1)
Other margin	158	132	26(2)
Open gross margin	$ 427	$ 310	$ 117
East Gas			
Open energy gross margin	$ 37	$ 18	$ 19(3)
Other margin	159	137	22(2)
Open gross margin	$ 196	$ 155	$ 41
West			
Open energy gross margin	$ 7	$ 12	$ (5)
Other margin	94	106	(12)(4)
Open gross margin	$ 101	$ 118	$ (17)
Other			
Open energy gross margin	$ 3	$	$ 3
Other margin	25	46	(21)(5)
Open gross margin	$ 28	$ 46	$ (18)
Total			
Open energy gross margin(6)	$ 316	$ 208	$ 108
Other margin(6)	436	421	15
Open gross margin(6)	$ 752	$ 629	$ 123

(1) Increase primarily as a result of higher unit margins (higher power prices partially offset by higher fuel costs) and improved generation driven by

increased demand related to weather. This increase is partially offset by higher outages.

(2) Increase primarily as a result of RPM capacity payments.

(3) Increase primarily as a result of higher unit margins (higher power prices partially offset by higher fuel costs).

(4) Decrease primarily as a result of a decline in capacity payments.

(5) Decrease primarily as a result of expiration of a power purchase agreement in December 2009.

(6) The most directly comparable GAAP financial measure is income (loss) from continuing operations before income taxes. See Non-GAAP Performance

Measures.

Hedges and Other Items.

	Nine Months Ended September 30,		
	2010	2009	Change
		(in millions)	
Power	$ 3	$ 51	$ (48)(1)
Fuel	(9)	(186)	177(2)
Tolling/other	7	27	(20)(3)
Hedges and other items income (loss)	$ 1	$ (108)	$ 109

(1) Decrease primarily as a result of decline in hedges of generation.

(2) Increase primarily as a result of (a) $154 million driven by improved results of fuel hedges in 2010 as compared to 2009 and additional costs incurred in 2009 to reduce fixed price coal commitments for future periods in our East Coal segment and (b) $22 million reduction in lower market valuation adjustments to fuel inventory in our East Coal segment.

(3) Decrease primarily as a

result of a
decline in
results of gas
transportation
margins.

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Unrealized Gains (Losses) on Energy Derivatives.

	Nine Months Ended September 30, 2010	2009	Change
		(in millions)	
Revenues unrealized	$ 99	$ (51)	$ 150
Cost of sales unrealized	13	21	(8)
Net unrealized gains (losses) on energy derivatives	$ 112	$ (30)	$ 142(1)

(1) Net change primarily as a result of $131 million in gains from changes in prices on our energy derivatives marked to market and $11 million in gains driven by the reversal of previously recognized unrealized losses on energy derivatives which settled during the period.

Operation and Maintenance.

	Nine Months Ended September 30, 2010	2009	Change
		(in millions)	
Plant operation and maintenance	$ 355	$ 305	$ 50(1)
REMA leases	45	45	
Taxes other than income and insurance	27	30	(3)
Information Technology, Risk and other salaries and benefits	21	21	
Commercial Operations	10	13	(3)
Severance	2	5	(3)
Other, net		10	(10)

Operation and maintenance	$ 460	$ 429	$ 31

(1) Increase primarily as a result of $62 million increase in planned outages and projects spending primarily in our East Coal and West segments. This increase was partially offset by (a) $6 million decrease in base operation and maintenance expense as a result of the implementation of our plant-specific operating model primarily in our East Coal and Other segments and (b) $6 million decrease in services and support.

General and Administrative.

	Nine Months Ended September 30,		
	2010	2009	Change
	(in millions)		
Salaries and benefits	$ 38	$ 42	$ (4)
Merger-related costs	19		19
Professional fees, contract services and information systems maintenance	11	16	(5)
Severance		3	(3)
Other, net	9	19	(10)
General and administrative	$ 77	$ 80	$ (3)

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Efficiency Measures Total Controllable Costs.

	Nine Months Ended September 30,		
	2010	2009	Change
	(dollars in millions, except per MWh and per MW data)		
Operation and maintenance, excluding severance[1]	$ 458	$ 424	$ 34
REMA lease expense	(45)	(45)	
General and administrative, excluding severance and merger-related costs[1]	58	77	(19)
Maintenance capital expenditures	24	45	(21)
Total Controllable Costs	$ 495	$ 501	$ (6)
TWh generation	17.9	16.9	1.0
Total Controllable Costs/MWh	$ 28	$ 30	$ (2)
MW capacity [2]	14,586	14,563	23
Total Controllable Costs ($ thousands)/MW capacity	$ 33.9	$ 34.4	$ (0.5)

(1) Excludes (a) severance charges incurred in connection with (i) repositioning the company in connection with the sale of our retail business and (ii) implementing our plant-specific operating model, classified in operation and maintenance and general and administrative and (b) merger-related costs classified in general and administrative. Merger-related

costs include financial advisory fees, legal costs, stock-based compensation expense related to the modification of our stock options and other merger-related expenses.

(2) MW capacity changed from September 30, 2009 to September 30, 2010 as a result of MW re-ratings that occurred during the fourth quarter of 2009 and the third quarter of 2010.

Total Controllable Costs Reconciliation.

	Nine Months Ended September 30,					
	2010		2009		Change	
	(dollars in millions, except per MWh and per MW data)					
Operation and maintenance (O&M)	$	460	$	429	$	31
General and administrative (G&A)		77		80		(3)
Capital expenditures		64		158		(94)
Total operation and maintenance, general and administrative and capital expenditures	$	601	$	667	$	(66)
Total Controllable Costs	$	495	$	501	$	(6)
REMA lease expense in operation and maintenance		45		45		
Severance included in operation and maintenance		2		5		(3)
Severance included in general and administrative				3		(3)
Merger-related costs included in general and administrative		19				19
Environmental capital expenditures		32		91		(59)
Capitalized interest		8		22		(14)
Total operation and maintenance, general and administrative and capital expenditures	$	601	$	667	$	(66)

TWh generation		17.9		16.9		1.0
Total O&M, G&A and capital expenditure/MWh	$	34	$	39	$	(5)
MW capacity		14,586		14,563		23
Total O&M, G&A and capital expenditures ($ thousands)/MW capacity	$	41.2	$	45.8	$	(4.6)

Western States Litigation and Similar Settlements. See note 12 to our interim financial statements.

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Gains on Sales of Assets and Emission and Exchange Allowances, Net.

	Nine Months Ended September 30, 2010	2009	Change
		(in millions)	
CO_2 exchange allowances	$	$ 10	$ (10)
SO_2 and NO_x emission allowances		7	(7)
Other, net	2	4	(2)
Gains on sales of assets and emission and exchange allowances, net	$ 2	$ 21	$ (19)

Long-lived Assets Impairments. See note 7 to our interim financial statements.
Depreciation and Amortization.

	Nine Months Ended September 30, 2010	2009	Change
		(in millions)	
Depreciation on plants	$ 167	$ 166	$ 1
Other, net depreciation	9	12	(3)
Depreciation	176	178	(2)[(1)]
Amortization of emission allowances	18	22	(4)[(2)]
Other, net amortization	2	3	(1)
Amortization	20	25	(5)
Depreciation and amortization	$ 196	$ 203	$ (7)

(1) Decrease primarily as a result of reduced depreciation expense of (a) $15 million as a result of our December 31, 2009 and March 31, 2010 long-lived asset impairments (see note 7 to our interim financial statements) and

(b) $3 million related to early retirements of plant components at various plants in our East Coal segment in 2009. These decreases were partially offset by (a) $10 million in net early retirements of plant components at our Cheswick plant and (b) $5 million of additional depreciation expense related to an equipment upgrade at our Keystone plant.

(2) Decrease primarily as result of lower weighted average cost of SO_2 allowances partially offset by (a) net increase in volume of SO_2 and NO_x allowances used and (b) higher weighted average cost of NO_x allowances. The decrease was primarily in our East Coal segment.

Debt Extinguishments Gains. This represents gains on extinguishments of our senior secured notes.

Interest Expense.

	Nine Months Ended September 30, 2010	2009	Change
	(in millions)		
Fixed-rate debt	$ 125	$ 157	$ (32)[1]
Deferred financing costs	5	5	
Amortization of fair value adjustment of acquired debt	(5)	(9)	4
Capitalized interest	(8)[2]	(22)[3]	14
Other, net	5	6	(1)
Interest expense	$ 122	$ 137	$ (15)

(1) Decrease as a result of a reduction in fixed-rate debt primarily due to (a) $400 million in payments of the Orion Power Holdings, Inc. senior notes in May 2010 and (b) purchases of senior secured 6.75% notes in 2009.

(2) Relates primarily to environmental capital expenditures for SO_2 emission reductions at our Cheswick plant.

(3) Relates primarily to environmental capital expenditures for SO_2 emission reductions at our Cheswick and Keystone plants.

Other, Net. This amount did not change significantly.

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Income Tax Expense (Benefit). See note 11 to our interim financial statements. A reconciliation of the federal statutory income tax rate to the effective income tax rate is:

	Nine Months Ended September 30,	
	2010	**2009**
Federal statutory rate	(35)%	(35)%
Additions (reductions) resulting from:		
Federal valuation allowance	48(1)	4
State income taxes, net of federal income taxes	6(2)	(2)
Other		1(3)
Effective rate	19%	(32)%

(1) Of this percentage, $172 million (48%) relates to additional valuation allowance.

(2) Of this percentage, $42 million (12%) relates to additional valuation allowance.

(3) Includes $15 million of a valuation allowance release offset by $15 million of expired foreign net operating loss carryforwards.

Income from Discontinued Operations. See note 18 to our interim financial statements.

Liquidity and Capital Resources

Proposed Merger with Mirant. See Recent Events Proposed Merger with Mirant for discussion of financing commitments in connection with the proposed merger.

Overview. We are committed to a strong balance sheet and ample liquidity that will enable us to avoid distress in cyclical troughs and access capital markets throughout the cycle. We think our liquidity has and continues to exceed the level required to achieve this goal. As of October 26, 2010, we had total available liquidity of $1.4 billion, comprised of cash and cash equivalents ($778 million), unused borrowing capacity ($500 million) and letters of credit capacity ($168 million).

Gross Debt Goal. Our goal for gross debt (total GAAP debt plus our REMA operating leases) is $1.25 billion to $1.75 billion. The comparable target for total GAAP debt, based on the current balance for our REMA leases of $411 million, is approximately $800 million to $1.3 billion. As of September 30, 2010, we had gross debt of $2.4 billion and GAAP debt of $2.0 billion. Our gross debt and GAAP debt were reduced by $400 million in May 2010 through the retirement of our Orion Power senior notes. We think that the non-GAAP measure gross debt is a useful and relevant measure of our financial obligations and the strength and flexibility of our capital structure.

In the future, we could use a variety of means to achieve our gross debt goal, including retirements at maturity, open market purchases, call provisions and tender offers.

Cash Flows. During the nine months ended September 30, 2010, we generated $252 million in operating cash flows from continuing operations, including the net changes in margin deposits of $104 million (cash inflow). See Historical Cash Flows for further detail of our cash flows from operating activities and explanation of our $51 million and $398 million use of cash from investing activities from continuing operations and use of cash from financing activities from continuing operations, respectively, during the nine months ended September 30, 2010.

See note 11(c) to our interim financial statements regarding an expected income tax cash payment of approximately $55 to $60 million relating to California-related matters in the next twelve months. See note 13(c) to our interim financial statements regarding an expected cash payment of approximately $60 million relating to our Texas franchise audit in the next twelve months.

We continue to monitor our business and hedging with the goal of at least breaking even on a free cash flow basis irrespective of the commodity price environment. Based on our assessment of the economic environment and volatility in commodity markets, we have hedged, with swaps, approximately 35% and 49% of estimated power generation from our PJM coal plants (which are in our East Coal segment) for 2010 and 2011 (based on MWh), respectively. We have hedged an additional 4%, 13% and 7% of this estimated power generation for 2010, 2011 and 2012, respectively, with financial options to retain meaningful energy margin upside for market improvements.

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Non-GAAP Cash Flows Measures.

	Nine Months Ended September 30, 2010		Nine Months Ended September 30, 2009	
	(in millions)			
Operating cash flow from continuing operations	$	252	$	(275)
Change in margin deposits, net[1]		(104)		240
Adjusted cash flow provided by (used in) continuing operations		148		(35)
Capital expenditures		(64)		(158)
Proceeds from sales of emission and exchange allowances[2]				19
Purchases of emission allowances[2]				(8)
Free cash flow provided by (used in) continuing operations	$	84	$	(182)

(1) We post collateral to support a portion of our commodity sales and purchase transactions. The collateral provides assurance to counterparties that contractual obligations will be fulfilled. As the obligations are fulfilled, the collateral is returned. We commonly use both cash and letters of credit as collateral. The use of cash as collateral appears as an asset on the balance sheet and as a use of

cash in operating cash flow. When cash collateral is returned, the asset is eliminated from the balance sheet and it appears as a source of cash in operating cash flow. We think that it is useful to exclude changes in margin deposits, since changes in margin deposits reflect the net inflows and outflows of cash collateral and are driven by hedging levels and changes in commodity prices, not by the cash flow generated by the business related to sales and purchases in the reporting period.

(2) The cash flows from sales and purchases of emission and exchange allowances are classified as investing cash flows for GAAP purposes; however, we purchase and sell emission and exchange

allowances in connection with the operation of our generating assets. As part of our effort to operate our business efficiently, we periodically sell emission and exchange allowances inventory in excess of our forward power sales commitments if the price is above our view of their value. Consistent with subtracting capital expenditures (which is a GAAP investing cash flow activity) in calculating free cash flow, we add sales and subtract purchases of emission and exchange allowances.

Our non-GAAP cash flow measures may not be representative of the amount of residual cash flow, if any, that is available to us for discretionary expenditures, since they may not include deductions for all non-discretionary expenditures. We think, however, that our non-GAAP cash flow measures are useful because they provide a representation of our cash flows from the applicable period available to service debt on a normalized basis, both before and after capital expenditures and emission and exchange allowances activity. The most directly comparable GAAP financial measure is operating cash flow from continuing operations.

Other. See Risk Factors in Item 1A and Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources in Item 7 of our Form 10-K and notes 7 and 15 to our consolidated financial statements in our Form 10-K. Also see Risk Factors in Item 1A of this report.

Credit Risk

By extending credit to our counterparties, we are exposed to credit risk. For discussion of our credit risk policy and exposures, see note 6 to our interim financial statements.

Off-Balance Sheet Arrangements

As of September 30, 2010, we have no off-balance sheet arrangements.

Historical Cash Flows

Cash Flows Operating Activities

	Nine Months Ended September 30, 2010	2009 (in millions)	Change
Operating loss	$ (244)	$ (200)	$ (44)
Depreciation and amortization	196	203	(7)
Western states litigation and similar settlements	17		17
Western states litigation and similar settlements payments		(3)	3
Gains on sales of assets and emission allowances, net	(2)	(21)	19
Long-lived assets impairments	361		361
Net changes in energy derivatives	(107)(1)	30(2)	(137)
Margin deposits, net	104	(240)	344
Change in accounts and notes receivable and accounts payable, net	6	108	(102)
Change in inventory	48	(1)	49
Net option premiums purchased	(3)	(30)	27
Interest payments, net of capitalized interest	(93)	(89)	(4)
Income tax payments, net of refunds	(1)	(5)	4
Prepaid lease obligation	(8)	(19)	11
Construction deposit refund		15	(15)
Pension contributions	(6)	(20)	14
Other, net	(16)	(3)	(13)
Net cash provided by (used in) continuing operations from operating activities	252	(275)	527
Net cash provided by discontinued operations from operating activities	35	534	(499)
Net cash provided by operating activities	$ 287	$ 259	$ 28

(1) Includes unrealized gains on energy derivatives of $112 million.

(2) Includes unrealized losses on energy derivatives of $30 million.

Our cash provided by operating activities is affected by, among other things, changes in energy prices and fluctuations in our working capital requirements. Net cash provided by/used in operating activities from continuing operations increased by $527 million for the nine months ended September 30, 2010, compared to the same period in 2009, primarily as a result of the following:

Open Gross Margin. Open gross margin provided an increase in cash of $123 million as a result of (a) higher power prices and improved generation driven by increased demand in our East Coal segment and (b) RPM capacity payments in our East Coal and East Gas segments during 2010, partially offset by (a) decrease resulting from the expiration of a power purchase agreement in our Other segment in December 2009 and (b) a decline in capacity payments in our West segment. See Consolidated Results of Operations for the nine months ended September 30, 2010 compared to nine months ended September 30, 2009 for additional discussion of our performance.

Hedges and Other Items. Hedges and other items provided an increase in cash of $131 million, which excludes lower market valuation adjustments to fuel inventory, primarily as a result of improved results of fuel hedges in 2010 as compared to 2009 and additional costs incurred in 2009 to reduce fixed price coal commitments for future periods in our East Coal segment. The increase was partially offset by declines in hedges of generation and gas transportation margins. See Consolidated Results of Operations for the nine months ended September 30, 2010 compared to nine months ended September 30, 2009 for additional discussion of our performance.

Margin Deposits. Margin deposits provided an increase in cash of $344 million primarily as a result of the return of collateral posted with certain counterparties compared to an increase in initial margin requirements related to a new hedging strategy during 2009.

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Inventory. Cash used for inventory decreased by $71 million, which excludes lower market valuation adjustments to fuel inventory, primarily as a result of a reduction of coal and materials and supply inventory in 2010.

Option premiums purchased. Cash used for options premiums decreased by $27 million.

These increases in cash provided by and decreases in cash used in operating activities were partially offset by the following:

Operations and maintenance expense. Operations and maintenance expense increased by $31 million primarily as a result of an increase in planned outages and projects spending primarily at our East Coal and West segments. See Consolidated Results of Operations for the nine months ended September 30, 2010 compared to nine months ended September 30, 2009 for additional discussion of our performance.

Net accounts receivable and payable. The net cash flows of accounts receivable and payable decreased by $102 million primarily as a result of (a) the implementation of weekly settlements for the PJM Market in June 2009, (b) the timing of collections of receivables related to coal sales in early 2009 and (c) gas sales prices in 2009.

Cash Flows Investing Activities

	Nine Months Ended September 30, 2010	2009	Change
		(in millions)	
Capital expenditures	$ (64)	$ (158)	$ 94(1)
Proceeds from sales of assets	8	36	(28)
Proceeds from sales of emission and exchange allowances		19	(19)
Purchases of emission allowances		(8)	8
Other, net	5	4	1
Net cash used in continuing operations from investing activities	(51)	(107)	56
Net cash provided by (used in) discontinued operations from investing activities	(4)	314	(318)
Net cash provided by (used in) investing activities	$ (55)	$ 207	$ (262)

(1) Decrease primarily due to (a) $73 million decrease in environmental capital expenditures (including capitalized interest) primarily for SO_2 emission reductions at our Cheswick

and Keystone plants, which are included in our East Coal segment (the scrubber project of our Keystone plant was completed in 2009, the scrubber project for our Cheswick plant was halted in mid-2009 and was resumed and completed in 2010) and (b) $21 million decrease in maintenance capital expenditures.

Cash Flows   Financing Activities

	Nine Months Ended September 30,		
	2010	**2009**	**Change**
		(in millions)	
Payments of long-term debt	$ (400)[1]	$ (59)[2]	$ (341)
Proceeds from issuances of stock	2	4	(2)
Net cash used in continuing operations from financing activities	(398)	(55)	(343)
Net cash used in discontinued operations from financing activities		(261)	261
Net cash used in financing activities	$ (398)	$ (316)	$ (82)

(1) Includes $400 million in payments of the Orion Power Holdings, Inc. senior notes.

(2) Includes $59 million of purchases of

senior secured
notes.

New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates

New Accounting Pronouncements

See notes 1 and 4 to our interim financial statements.

Significant Accounting Policies

See note 2 to our consolidated financial statements in our Form 10-K.

Critical Accounting Estimates

See Management s Discussion and Analysis of Financial Condition and Results of Operations Accounting Estimates New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates Critical Accounting Estimates in Item 7 in our Form 10-K and note 2 to our consolidated financial statements in our Form 10-K.

Long-Lived Assets.

We consider the estimate used to assess the recoverability of our long-lived assets (property, plant and equipment and intangible assets) a critical accounting estimate. See notes 2(g), 4 and 5 to our consolidated financial statements in our Form 10-K. See note 7 to our interim financial statements for further discussion regarding our $113 million impairment charges for our Titus and New Castle plants (each in our East Coal segment) recognized during the three months ended September 30, 2010 and our $248 million impairment charges for our Elrama and Niles plants (each in our East Coal segment) recognized during the three months ended March 31, 2010.

Following our current methodology, as of September 30, 2010, we had four additional plants and related intangible assets with a combined carrying value of $597 million, where the undiscounted cash flows were close to the carrying values. If market conditions or environmental and regulatory assumptions change negatively in the future, it is likely that these four plants (and possibly others) could be impaired. Of these four plants, three are included in the discussion below about the sensitivities. If the undiscounted cash flows would not have exceeded the net book value for the other plant, this would have necessitated fair value estimates for that plant which could have resulted in an impairment loss of approximately $25 million based on key assumptions used in our fair value analyses as of September 30, 2010.

Long-Lived Assets Effect if Different Assumptions Used.

The estimates and assumptions used to determine whether long-lived assets are recoverable or whether impairment exists are subject to a high degree of uncertainty. Different assumptions as to power prices, fuel costs, our future cost structure, environmental assumptions and remaining useful lives and ultimate disposition values of our plants would result in estimated future cash flows that could be materially different than those considered in the recoverability assessments as of September 30, 2010 and March 31, 2010 and could result in having to estimate the fair value of other plants.

Use of a different risk-adjusted discount rate would result in fair value estimates for the four plants for which we recorded an impairment during the three months ended September 30 or March 31, 2010 that could be materially greater than or less than the fair value estimates as of each applicable date. Any future fair value estimates for the plants where an impairment has been recognized that are greater than the fair value estimates at the time of impairment recognition will not result in reversal of previously recognized impairments.

September 30, 2010 Recoverability Assessments. The undiscounted cash flow scenarios we considered in assessing the recoverability of our long-lived assets are those which we think are most likely to occur based on market data as of September 30, 2010. If we had solely utilized the 5-year market forecast with escalation scenario, the carrying value of six additional plants and related intangible assets ($669 million) would have been greater than the undiscounted cash flows. This would have necessitated fair value estimates for those plants which could have resulted in an impairment loss of approximately $360 million based on the key assumptions used in our fair value analyses as of September 30, 2010. Alternatively, if we had solely utilized the 5-year market forecast with fundamental view, the carrying value of one plant and related intangible assets ($344 million) would have been greater than the undiscounted future cash flows. This would have necessitated fair value estimates for that plant which could have resulted in an impairment loss of approximately $240 million based on the key assumptions used in our fair value analyses as of September 30, 2010.

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As of September 30, 2010, the discounted cash flow scenarios we considered in determining the fair values of our Titus and New Castle long-lived assets are those which we think are most representative of a market participant view. If we had solely utilized the 5-year market forecast with escalation scenario, the fair value of the Titus long-lived assets would have been $43 million (resulting in an impairment of $62 million as opposed to $74 million recognized). Alternatively, if we had solely utilized the 5-year market forecast with fundamental view, the fair value of the Titus long-lived assets would have been $19 million (resulting in an impairment of $86 million as opposed to $74 million recognized). If we had solely utilized the 5-year market forecast with escalation scenario, the fair value of the New Castle long-lived assets would have been $5 million (resulting in an impairment of $40 million as opposed to $39 million recognized). Alternatively, if we had solely utilized the 5-year market forecast with fundamental view, the fair value of the New Castle long-lived assets would have been $7 million (resulting in an impairment of $38 million as opposed to $39 million recognized).

March 31, 2010 Recoverability Assessments. The undiscounted cash flow scenarios we considered in assessing the recoverability of our long-lived assets are those which we think are most likely to occur based on market data as of March 31, 2010. If we had solely utilized the 5-year market forecast with escalation scenario, the carrying value of three additional plants and related intangible assets ($259 million) would have been greater than the undiscounted cash flows. This would have necessitated fair value estimates for those plants which could have resulted in an impairment loss of approximately $200 million based on the key assumptions used in our fair value analyses as of March 31, 2010. Alternatively, if we had solely utilized the 5-year market forecast with fundamental view, the carrying value of one plant and related intangible assets ($108 million) would have been greater than the undiscounted future cash flows. This would have necessitated fair value estimates for that plant which could have resulted in an impairment loss of approximately $75 million based on the key assumptions used in our fair value analyses as of March 31, 2010.

As of March 31, 2010, the discounted cash flow scenarios we considered in determining the fair values of our Elrama and Niles long-lived assets are those which we think are most representative of a market participant view. If we had solely utilized the 5-year market forecast with escalation scenario, the fair value of the Elrama long-lived assets would have been $47 million (resulting in an impairment of $214 million as opposed to $193 million recognized). Alternatively, if we had solely utilized the 5-year market forecast with fundamental view, the fair value of the Elrama long-lived assets would have been $89 million (resulting in an impairment of $172 million as opposed to $193 million recognized). If we had solely utilized the 5-year market forecast with escalation scenario, the fair value of the Niles long-lived assets would have been $25 million (resulting in an impairment of $56 million as opposed to $55 million recognized). Alternatively, if we had solely utilized the 5-year market forecast with fundamental view, the fair value of the Niles long-lived assets would have been $28 million (resulting in an impairment of $53 million as opposed to $55 million recognized).

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks and Risk Management

Our primary market risk exposure relates to fluctuations in commodity prices. See Quantitative and Qualitative Disclosures About Market Risk in Item 7A of our Form 10-K and notes 4 and 5 to our interim financial statements.

Non-Trading Market Risks

Commodity Price Risk

As of September 30, 2010, the fair values of the contracts related to our net non-trading derivative assets and liabilities are (asset (liability)):

Source of Fair Value	Twelve Months Ending September 30, 2011	Remainder of 2011	2012	2013	2014	2015 and thereafter	Total fair value
				(in millions)			
Prices actively quoted (Level 1)	$ 93	$ 25	$ 6	$	$	$	$ 124
Prices provided by other external sources (Level 2)	(30)	(6)	(13)				(49)
Prices based on models and other valuation methods (Level 3)	21	4					25
Total mark-to-market non-trading derivatives	$ 84	$ 23	$ (7)	$	$	$	$ 100

The fair values shown in the table above are subject to significant changes as a result of fluctuating commodity forward market prices, volatility and credit risk. Market prices assume a functioning market with an adequate number of buyers and sellers to provide liquidity. Insufficient market liquidity could significantly affect the values that could be obtained for these contracts, as well as the costs at which these contracts could be hedged. For further discussion of how we arrive at these fair values, see note 4 to our interim financial statements and Management s Discussion and Analysis of Financial Condition and Results of Operations New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates Critical Accounting Estimates in Item 7 of our Form 10-K.

A hypothetical 10% movement in the underlying energy prices would have the following potential loss impacts on our non-trading derivatives:

As of	Market Prices	Earnings Impact	Fair Value Impact
		(in millions)	
September 30, 2010	10% increase	$ (26)	$ (26)
December 31, 2009	10% increase	(47)	(47)

Interest Rate Risk

As of September 30, 2010 and December 31, 2009, we have no variable rate debt outstanding. We earn interest income, for which the interest rates vary, on our cash and cash equivalents and net margin deposits. During the nine months ended September 30, 2010 and twelve months ended December 31, 2009, we had no variable rate interest expense and our interest income was $0 and $2 million, respectively.

If interest rates decreased by one percentage point from their September 30, 2010 and December 31, 2009 levels, the fair values of our fixed rate debt from continuing operations would have increased by $117 million and $126 million, respectively.

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Trading Market Risks

As of September 30, 2010, the fair values of the contracts related to our legacy trading and non-core asset management positions and recorded as net derivative assets and liabilities are (asset (liability)):

Source of Fair Value	Twelve Months Ending September 30, 2011	Remainder of 2011	2012	2013	2014	2015 and thereafter	Total fair value
				(in millions)			
Prices actively quoted (Level 1)	$ 3	$	$	$	$	$	$ 3
Prices provided by other external sources (Level 2)							
Prices based on models and other valuation methods (Level 3)	(1)						(1)
Total	$ 2	$	$	$	$	$	$ 2

The fair values in the above table are subject to significant changes based on fluctuating market prices and conditions. See the discussion above related to non-trading derivative assets and liabilities for further information on items that impact our portfolio of trading contracts.

Our consolidated realized and unrealized margins relating to trading activities, including both derivative and non-derivative instruments, are (income (loss)):

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(in millions)			
Realized	$ 7	$ 7	$ 20	$ 25
Unrealized	(5)	(2)	(17)	(4)
Total	$ 2	$ 5	$ 3	$ 21

An analysis of these net derivative assets and liabilities is:

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(in millions)	
Fair value of contracts outstanding, beginning of period	$ 19	$ 30
Contracts realized or settled	(20)[1]	(25)[2]
Changes in fair values attributable to market price and other market changes	3	21
Fair value of contracts outstanding, end of period	$ 2	$ 26

(1) Amount includes realized gain of $20 million.

(2) Amount includes realized gain of $25 million.

The daily value-at-risk for our legacy trading and non-core asset management positions is:

	2010[1]	2009
	(in millions)	
As of September 30	$	$ 1
Three months ended September 30:		
Average		1
High	1	1
Low		1
Nine months ended September 30:		
Average		2
High	1	4
Low		1

(1) The major parameters for calculating daily value-at-risk remain the same during 2010 as disclosed in Quantitative and Qualitative Disclosures About Market Risk in Item 7A of our Form 10-K.

Fair Value Measurements

In determining fair value for our derivative assets and liabilities, we generally use the market approach and incorporate assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and/or the risks inherent in the inputs to the valuation techniques.

A fair value hierarchy exists for inputs used in measuring fair value that maximizes the use of observable inputs (Level 1 or Level 2) and minimizes the use of unobservable inputs (Level 3) by requiring that the observable inputs be used when available. Derivative instruments classified as Level 2 primarily include emission allowances futures that are exchanged-traded and over-the-counter (OTC) derivative instruments such as generic swaps, forwards and options. The fair value measurements of these derivative assets and liabilities are based largely on unadjusted indicative quoted prices from independent brokers in active markets who regularly facilitate our transactions. An active market is considered to have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. Derivative instruments for which fair value is calculated using quoted prices that are deemed not active or that have been extrapolated from quoted prices in active markets are classified as Level 3. For certain natural gas and power contracts, we adjust seasonal or calendar year quoted prices based on historical observations to represent fair value for each month in the season or calendar year, such that the average of all months is equal to the quoted price. A derivative instrument that has a tenor that does not span the quoted period is considered an unobservable Level 3 measurement.

We evaluate and validate the inputs we use to estimate fair value by a number of methods, including validating against market published prices and daily broker quotes obtainable from multiple pricing services. For OTC derivative instruments classified as Level 2, indicative quotes obtained from brokers in liquid markets generally represent fair value of these instruments. We think these price quotes are executable. Adjustments to the quotes are adjustments to the bid or ask price depending on the nature of the position to appropriately reflect exit pricing and are considered a Level 3 input to the fair value measurement. In less liquid markets such as coal, in which a single broker s view of the market is used to estimate fair value, we consider such inputs to be unobservable Level 3 inputs. We do not use third party sources that determine price based on market surveys or proprietary models.

We report our derivative assets and liabilities, for which the normal purchase/normal sale exception has not been made, at fair value and consider it to be a critical accounting estimate because these estimates are highly susceptible to change from period to period and are dependent on many subjective factors, including:

- estimated forward market price curves
- valuation adjustments relating to time value
- liquidity valuation adjustments
- credit adjustments, based on the credit standing of the counterparties and our own non-performance risk

Derivative assets are discounted for credit risk using a yield curve representative of the counterparty s probability of default. The counterparty s default probability is based on a modified version of published default rates, taking 20-year historical default rates from Standard & Poor s and Moody s and adjusting them to reflect a rolling five-year average. For derivative liabilities, fair value measurement reflects the nonperformance risk related to that liability, which is our own credit risk. We derive our nonperformance risk by applying our credit default swap spread against the respective derivative liability.

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To determine the fair value for Level 3 energy derivatives where there are no market quotes or external valuation services, we rely on various modeling techniques. We use a variety of valuation models, which vary in complexity depending on the contractual terms of, and inherent risks in, the instrument being valued. We use both industry-standard models as well as internally developed proprietary valuation models that consider various assumptions such as market prices for power and fuel, price shapes, ancillary services, volatilities and correlations as well as other relevant factors. There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts are ultimately settled.

For additional information regarding our derivative assets and liabilities, see notes 4 and 5 to our interim financial statements.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, have evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (1934 Act)) as of September 30, 2010, the end of the period covered by this Form 10-Q. Based on this evaluation, our chief executive officer and chief financial officer concluded that, as of September 30, 2010, our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the 1934 Act) during the period ended September 30, 2010, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II.
OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

See note 13 to our interim financial statements in this Form 10-Q.

ITEM 1A. RISK FACTORS

We may not be able to obtain in the anticipated timeframe, or at all, satisfaction of all conditions to complete the merger or, in order to do so, we may be required to comply with material restrictions or conditions that may negatively affect the combined company. Failure to complete our merger with Mirant could negatively impact our future business and financial results.

On April 11, 2010, we announced the execution of a merger agreement with Mirant. Before the merger may be completed, the parties must satisfy all conditions set forth in the agreement, including the receipt of acceptable debt financing in an amount sufficient to fund the refinancing transactions contemplated by the merger agreement, and that there be no injunction prohibiting the merger. Moreover, upon completion of its merger review the DOJ could seek to impose conditions on the merger that could have an adverse effect on Mirant, RRI or the combined company. Furthermore, purported class actions have been brought on behalf of holders of Mirant common stock, for which settlement is pending. See notes (2) and 13(d) to our interim financial statements for further discussion.

Any failure to settle the class actions or to satisfy all the conditions set forth in the merger agreement, could delay or prevent the merger, and could result in the merger costing more than we expect or could materially adversely affect the synergies and other benefits that we expect to achieve from the merger and the integration of the respective businesses.

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We cannot make any assurances that the settlement of the class actions will be approved or that we will be able to satisfy all the conditions to the merger. If the merger with Mirant is not completed, our financial results may be adversely affected because of a number of risks, including, but not limited to, the following:

- we will be required to pay costs relating to the merger, including legal, accounting, financial advisory, filing and printing costs, whether or not the merger is completed, and

- we could also be subject to litigation related to any failure to complete the merger.

If completed, our merger with Mirant may not achieve its intended results.

We entered into the merger agreement with the expectation that the merger would result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether our businesses can be integrated in an efficient and effective manner. It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of each company s ongoing businesses, processes and systems or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, any of which could adversely affect the combined company s ability to achieve the anticipated benefits of the merger. The combined company s results of operations could also be adversely affected by any issues attributable to either company s operations that arise or are based on events or actions that occur prior to the closing of the merger. The companies may have difficulty addressing possible differences in corporate cultures and management philosophies. The integration process is subject to a number of uncertainties, and no assurance can be given that the anticipated benefits will be realized or, if realized, the timing of the realization. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect the combined company s future business, financial condition, operating results and prospects.

We will be subject to various uncertainties and contractual restrictions while the merger with Mirant is pending that could adversely affect our and the combined company s financial results.

Uncertainty about the effect of the merger with Mirant on employees, suppliers, customers and others may have an adverse effect on us and the combined company. These uncertainties may impair our ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, and could cause suppliers, customers and others that deal with us to seek to change existing business relationships. Employee retention and recruitment may be particularly challenging prior to the completion of the merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company.

The pursuit of the merger and the preparation for the integration of Mirant into our company may place a significant burden on our management and internal resources. Any significant diversion of management attention away from ongoing business and any difficulties encountered in the merger integration process could adversely affect our and the combined company s financial results.

In addition, the merger agreement restricts us, without Mirant s consent, from making certain acquisitions and dispositions and taking other specified actions. These restrictions may prevent us from pursuing attractive business opportunities and making other changes to our business prior to completion of the merger or termination of the merger agreement.

ITEM 6. EXHIBITS

Exhibits.

See Index of Exhibits.

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Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

RRI ENERGY, INC.
(Registrant)

November 3, 2010

By: /s/ Thomas C. Livengood
Thomas C. Livengood
Senior Vice President and Controller
(Duly Authorized Officer and Chief Accounting Officer)

INDEX OF EXHIBITS

The exhibits with the cross symbol (+) are filed with the Form 10-Q. The representations, warranties and covenants contained in the exhibits were made only for purposes of such exhibits, as of specific dates, solely for the benefit of the parties thereto, may be subject to limitations agreed upon by those parties and may be subject to standards of materiality that differ from those applicable to investors. Investors should read such representations, warranties and covenants (or any descriptions thereof contained in the exhibits) in conjunction with information provided elsewhere in this filing and in our other filings and should not rely solely on such information as characterizations of our actual state of facts.

Exhibit Number	Document Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
3.1	Third Restated Certificate of Incorporation	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended June 30, 2007	1-16455	3.1
3.2	Sixth Amended and Restated Bylaws	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended June 30, 2009	1-16455	3.2
4.1	Registrant has omitted instruments with respect to long-term debt in an amount that does not exceed 10% of the registrant s total assets and its subsidiaries on a consolidated basis and hereby undertakes to furnish a copy of any such agreement to the Securities and Exchange Commission upon request			
+10.1	Purchase Agreement by and among RRI Energy, Inc., Mirant Corporation, GenOn Escrow Corp. and J.P. Morgan Securities LLC, as representative of the several initial purchasers, dated as of September 20, 2010			
+10.2	Registration Rights Agreement by and among RRI Energy, Inc., J.P. Morgan Securities LLC, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities, Inc., Goldman, Sachs & Co. and Morgan Stanley & Co. Incorporated, dated as of October 4, 2010			
+10.3	Credit Agreement by and among RRI Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities, Inc., Goldman Sachs Bank USA, Morgan Stanley			

	Senior Funding, Inc., Royal Bank of Canada, The Royal Bank of Scotland plc, the other lenders from time to time party thereto and, from and after the closing date of the merger, Mirant Americas, Inc. (to be renamed GenOn Americas, Inc. on the closing date of the merger), dated as of September 20, 2010
+31.1	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
+31.2	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
+32.1	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
+101	Interactive Data File