RRI ENERGY INC
Form 10-Q
May 06, 2010

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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 March 31, 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 April 27, 2010, the latest practicable date for determination, RRI Energy, Inc. had 353,413,315 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, continue, could intend, may, plan, potential, predict, should, will, expect, objective, projection, forecast, goal 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, which could be materially and adversely affected by, among other things, the following:
  - obtaining mutually acceptable debt financing
  - 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.

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PART I.
FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended March 31, 2010	2009
	(thousands of dollars, except per share amounts)	
Revenues:		
Revenues (including $105,840 and $(4,288) unrealized gains (losses))	$ 604,710	$ 466,184
Expenses:		
Cost of sales (including $21,263 and $(39,455) unrealized gains (losses))	266,801	324,674
Operation and maintenance	160,415	157,146
General and administrative	20,718	29,014
Western states litigation and similar settlements	17,000	
Gains on sales of assets and emission and exchange allowances, net	(417)	(18,930)
Long-lived assets impairments	247,715	
Depreciation and amortization	62,320	67,858
Total operating expense	774,552	559,762
Operating Loss	(169,842)	(93,578)
Other Income (Expense):		
Interest expense	(46,041)	(46,919)
Interest income	216	248
Other, net	1,560	592
Total other expense	(44,265)	(46,079)
Loss from Continuing Operations Before Income Taxes	(214,107)	(139,657)
Income tax expense (benefit)	62,084	(33,876)
Loss from Continuing Operations	(276,191)	(105,781)
Loss from discontinued operations	(515)	(45,632)
Net Loss	$ (276,706)	$ (151,413)
Basic/Diluted Loss per Share:		
Loss from continuing operations	$ (0.78)	$ (0.30)
Loss from discontinued operations		(0.13)
Net loss	$ (0.78)	$ (0.43)

See Notes to our Unaudited Consolidated Interim Financial Statements

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RRI ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	March 31, 2010	December 31, 2009
	(thousands of dollars, except per share amounts)	
	(unaudited)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,124,069	$ 943,440
Restricted cash	28,835	24,093
Accounts and notes receivable, principally customer, net	114,453	152,569
Inventory	293,066	331,584
Derivative assets	201,626	132,062
Margin deposits	166,364	198,582
Prepayments and other current assets	90,914	86,844
Current assets of discontinued operations ($40,530 and $55,855 of margin deposits)	88,748	108,476
Total current assets	2,108,075	1,977,650
Property, plant and equipment, gross	5,924,765	6,330,879
Accumulated depreciation	(1,611,547)	(1,728,566)
Property, Plant and Equipment, net	4,313,218	4,602,313
Other Assets:		
Other intangibles, net	300,390	305,913
Derivative assets	91,656	53,138
Prepaid lease	282,700	277,370
Other ($29,212 and $33,793 accounted for at fair value)	190,673	239,078
Long-term assets of discontinued operations	5,224	5,232
Total other assets	870,643	880,731
Total Assets	$ 7,291,936	$ 7,460,694
LIABILITIES AND EQUITY		
Current Liabilities:		
Current portion of long-term debt and short-term borrowings	$ 401,090	$ 404,505
Accounts payable, principally trade	118,251	142,787
Derivative liabilities	132,441	151,461
Margin deposits	67,590	2,860
Other	253,673	169,898
Current liabilities of discontinued operations ($13,309 and $11,000 of margin deposits)	62,494	58,452

Total current liabilities		1,035,539		929,963
Other Liabilities:				
Derivative liabilities		56,229		61,436
Other		259,931		260,547
Long-term liabilities of discontinued operations		13,556		13,700
Total other liabilities		329,716		335,683
Long-term Debt		1,949,744		1,949,771
Commitments and Contingencies				
Temporary Equity Stock-based Compensation		5,132		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; 353,413,315 and 352,785,985 issued)		114		114
Additional paid-in capital		6,264,565		6,259,248
Accumulated deficit		(2,249,342)		(1,972,389)
Accumulated other comprehensive loss		(43,532)		(48,586)
Total stockholders equity		3,971,805		4,238,387
Total Liabilities and Equity	$	7,291,936	$	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)

	Three Months Ended March 31, 2010	2009
	(thousands of dollars)	
Cash Flows from Operating Activities:		
Net loss	$ (276,706)	$ (151,413)
Loss from discontinued operations	515	45,632
Loss from continuing operations	(276,191)	(105,781)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	62,320	67,858
Deferred income taxes	62,134	(33,771)
Net changes in energy derivatives	(125,805)	43,743
Gains on sales of assets and emission and exchange allowances, net	(417)	(18,930)
Western states litigation and similar settlements	17,000	
Long-lived assets impairments	247,715	
Other, net	(1,850)	4,800
Changes in other assets and liabilities:		
Accounts and notes receivable, net	37,219	86,831
Inventory	38,518	21,219
Margin deposits, net	96,948	105,783
Net derivative assets and liabilities	875	(10,298)
Accounts payable	(22,217)	2,287
Other current assets	(536)	(5,102)
Other assets	(8,486)	(4,221)
Taxes payable/receivable	1,190	(2,689)
Other current liabilities	43,757	40,076
Other liabilities	3,412	7,271
Net cash provided by continuing operations from operating activities	175,586	199,076
Net cash provided by discontinued operations from operating activities	25,922	289,161
Net cash provided by operating activities	201,508	488,237
Cash Flows from Investing Activities:		
Capital expenditures	(17,997)	(55,472)
Proceeds from sales of emission and exchange allowances	7	12,798
Purchases of emission allowances		(5,358)
Restricted cash	(4,742)	(3,801)
Other, net	1,400	
Net cash used in continuing operations from investing activities	(21,332)	(51,833)
Net cash used in discontinued operations from investing activities	(803)	(15,728)
Net cash used in investing activities	(22,135)	(67,561)

Cash Flows from Financing Activities:		
Proceeds from issuances of stock	1,881	2,163
Net cash provided by financing activities	1,881	2,163
Net Change in Cash and Cash Equivalents, Total Operations	181,254	422,839
Less: Net Change in Cash and Cash Equivalents, Discontinued Operations	625	16,891
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	$ 1,124,069	$ 1,410,315
Supplemental Disclosure of Cash Flow Information:		
Cash Payments:		
Interest paid (net of amounts capitalized) for continuing operations	$ (504)	$ (4,745)
Income taxes paid (net of income tax refunds received) for continuing operations	(20)	3,762

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 subsidiarie 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 16. 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 18 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 believe 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 due to 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. During the three months ended March 31, 2010 and 2009, we recorded $2 million and $24 million, respectively, for lower of average cost or market valuation adjustments in cost of sales.

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 3. 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.

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(2) Stock-based Compensation

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

	Three Months Ended March 31,	
	2010	2009
	(in millions)	
Stock-based incentive plans compensation expense (pre-tax) (1)	$ 2	$ 3

(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.

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 months ended March 31, 2010 and 2009 due to our net operating loss carryforwards.

(3) 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.

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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 believe 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 believe 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 6 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:

	March 31, 2010				
	Level 1[(1)]	**Level 2[(1)]**	**Level 3**	**Reclassifications[(2)]**	**Total Fair Value**
			(in millions)		
Derivative assets:					
Power	$ 83	$ 57	$ 10	$	$ 150
Power basis		3	7		10
Capacity energy			3		3
Natural gas	66		1		67
Natural gas basis	47				47
Coal			14		14
Other				2	2
Total derivative assets	$ 196	$ 60	$ 35	$ 2	$ 293
Derivative liabilities:					
Power	$ 10	$ 117	$ 7	$	$ 134
Power basis		9			9
Natural gas			5		5
Natural gas basis	30				30
Coal			7		7
Emissions		1			1
Other				2	2
Total derivative liabilities	$ 40	$ 127	$ 19	$ 2	$ 188
Cash equivalents[(3)]	$ 1,141	$	$	$	$ 1,141
Other assets[(4)]	$ 29	$	$	$	$ 29

(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 three months ended March 31, 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 and restricted cash in our consolidated balance sheet. We had $1.1 billion of cash equivalents included in cash and cash equivalents and $17 million of cash equivalents included in restricted cash.

(4) Include $12 million in available-for-sale securities (shares in a public exchange) and $17 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 March 31, 2010		Three Months Ended March 31, 2009	
	Net Derivatives (Level 3) (in millions)			
Balance, beginning of period (net asset (liability))	$	(28)	$	(114)
Total gains (losses) realized/unrealized:				
Included in earnings [(1)]		44		(74)
Purchases, issuances and settlements (net)				35
Transfers into Level 3[(2)]				
Transfers out of Level 3[(2)]				
Balance, end of period (net asset (liability))	$	16	$	(153)
Changes in unrealized gains (losses) relating to derivative assets and liabilities still held as of March 31, 2010 and 2009:				
Revenues	$	12	$	
Cost of sales		24		(68)
Total	$	36	$	(68)

(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 8) are:

	March 31, 2010		December 31, 2009	
	Carrying Value	Fair Value[(1)]	Carrying Value	Fair Value[(1)]
	(in millions)			

Fixed rate debt	$	2,351	$	2,237	$	2,355	$	2,333
Total debt	$	2,351	$	2,237	$	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 4.

(4) 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 3 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 (NO_X) 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 5 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 March 31, 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. 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 March 31, 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:

	March 31, 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)	$ 29	$ 14

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

(2) During the three months ended March 31, 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 March 31, 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	$ 154	$ 91	$ (98)	$ (56)	$ 91
Trading	48		(34)		14
Total derivatives	$ 202	$ 91	$ (132)	$ (56)	$ 105

We have the following derivative commodity contracts outstanding as of March 31, 2010:

		Notional Volumes(2)	
Commodity	Unit(1)	Current	Long-term
		(in millions)	
Power	MWh	(6)	(4)
Capacity energy	MWh	(1)	(1)
Natural gas (3)	MMBTU	9	18
Coal	MMBTU	106	148

(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 months ended March 31, 2010 and 2009 is:

	Three Months Ended March 31,			
	2010		2009	
Derivatives Not Designated as Hedging Instruments	**Revenues**	**Cost of Sales**	**Revenues**	**Cost of Sales**
	(in millions)			
Non-Trading Commodity Contracts:				
Unrealized[(1)]	$ 106	$ 26	$ (4)	$ (40)
Realized[(2)(3)(4)]	87	(68)	106	(8)
Total non-trading	$ 193	$ (42)	$ 102	$ (48)
Trading Commodity Contracts:				
Unrealized[(1)]	$	$ (5)	$	$
Realized[(2)]		5		19
Total trading	$	$	$	$ 19

(1) As discussed above, during 2007, we de-designated our remaining cash flow hedges; during the three months ended March 31, 2010 and 2009, previously measured ineffectiveness gains/losses in revenues reversing due 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 due to settlement of the derivative contracts. See note 7.

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 March 31,	
	2010	**2009**
	(in millions)	
Revenues	$	$
Cost of sales	1	11
Total[1]	$ 1	$ 11

(1) Includes realized and unrealized gains and losses on both derivative

instruments and
non-derivative
instruments.

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(5) 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 believe 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 March 31, 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	$ 23	$ 156	3(3)	$ 107
Non-investment grade	13	1	12		
No external ratings:					
Internally rated Investment grade	45		45	1(4)	41
Internally rated Non-investment grade	26	22	4		
Total	$ 263	$ 46	$ 217	4	$ 148

(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 a utility company, a power grid operator and a financial institution.

(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.

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

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

	March 31, 2010		December 31, 2009	
	Cash	Letters of Credit[1]	Cash	Letters of Credit[1]
	(in millions)			
Commodity contracts[2]	$ 132	$ 57	$ 207	$ 52
Derivative contracts receiving mark-to-market accounting treatment[2][3]	$ 58	$ 8	$ 97	$ 5
Other[4]	$ 47	$	$ 47	$

(1) See note 8.

(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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(6) 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 March 31, 2010, we had $4.6 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. See notes 2(g), 4 and 5 to our consolidated financial statements in our Form 10-K for further discussion.

Based on the further decline of commodity prices, our asset recoverability review was updated from December 31, 2009 to March 31, 2010. Our asset recoverability review 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. Following our current methodology (as described below), we had three additional plants and related intangible assets with a combined carrying value of $344 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 three plants (and possibly others) could be impaired.

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

	March 31, 2010
Undiscounted Cash Flow Scenarios Weightings:	
5-year market forecast with escalation(1)(2)	50%
5-year market forecast with fundamental view(1)	50%
Range of Assumptions in Fundamental View:	
Demand for power growth per year	1%-2%
After-tax rate of return on new construction(3)	6.5%-9.5%
Spread between natural gas and coal prices, $/MMBTU(4)	$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 March 16, 2010 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 March 16, 2010 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 for our two plants for which the undiscounted cash flows did not exceed the net book value of the long-lived assets.

	Elrama	Niles
Valuation approach weightings:		
Income approach	100%	100%
Market-based approach	0%	0%
Risk-adjusted discount rate for the estimated cash flows	15%	15%

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

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 due to the further decline in commodity prices. We believe 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 3 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.

	March 31, 2010			Q1 2010
	Level 1	Level 2	Level 3	Impairment Charges
	(in millions)			
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 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 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 two plants for which we recorded an impairment during the three months ended March 31, 2010 that could be materially greater than or less than the fair value estimates as of March 31, 2010. Any future fair value estimates for our Elrama and Niles long-lived assets that are greater than the fair value estimates as of March 31, 2010 will not result in reversal of the first quarter 2010 impairment charges.

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(7) Comprehensive Income (Loss)

The components of total comprehensive income (loss) are:

	Three Months Ended March 31,			
	2010		2009	
	(in millions)			
Net loss	$	(277)	$	(151)
Other comprehensive income (loss), net of tax:				
Deferred benefits		1		
Reclassification of net deferred loss from cash flow hedges into net income/loss		5		5
Unrealized gain (loss) on available-for-sale securities		(1)		1
Comprehensive loss	$	(272)	$	(145)

(8) Debt

Outstanding debt:

	March 31, 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	2.04%	$		$		1.98%	$		$	
Senior secured notes due 2014	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)	12.00				400(2)	12.00				400
PEDFA(3) fixed-rate bonds due 2036	6.75		371			6.75		371		
Total facilities, bonds and notes			1,950		400			1,950		400
Other:										
Adjustment to fair value of debt(4)					1					5
Total other debt					1					5
Total debt		$	1,950	$	401		$	1,950	$	405

(1)

The weighted average stated interest rates are as of March 31, 2010 or December 31, 2009.

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

(3) PEDFA is the Pennsylvania Economic Development Financing Authority. These bonds were issued for our Seward plant.

(4) Debt acquired in the Orion Power acquisition was adjusted to fair value as of the acquisition date. Included in interest expense is amortization of $4 million and $3 million for valuation adjustments for debt during the three months ended March 31, 2010 and 2009, respectively.

Amounts borrowed and available for borrowing under our revolving credit agreements as of March 31, 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		92	158

Total	$	750	$		$	92	$	658

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(9) Earnings (Loss) Per Share
The amounts used in the basic and diluted earnings (loss) per common share computations are the same:

	Three Months Ended March 31,	
	2010	2009
	(in millions)	
Loss from continuing operations (basic and diluted)	$ (276)	$ (106)

	Three Months Ended March 31,	
	2010	2009
	(shares in thousands)	
Weighted average shares outstanding (basic and diluted)	353,307	350,487

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

	Three Months Ended March 31,	
	2010	2009
	(shares in thousands)	
Shares excluded from the calculation of diluted earnings/loss per share	350(1)	446(1)
Shares excluded from the calculation of diluted earnings/loss per share because the exercise price exceeded the average market price	4,853(2)	7,851(2)

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

(2) Includes stock options.

(10) 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 March 31,	
	2010	2009
Federal statutory rate	(35)%	(35)%
Additions (reductions) resulting from:		
Federal valuation allowance	52(1)	11(2)
State income taxes, net of federal income taxes	10(3)	(1)(4)

Other	2	1
Effective rate	29%	(24)%

(1) Of this percentage, $112 million (52%) relates to additional valuation allowance.

(2) Of this percentage, $16 million (11%) relates to additional valuation allowance.

(3) Of this percentage, $32 million (15%) relates to additional valuation allowances.

(4) Of this percentage, $6 million (4%) relates to additional valuation allowances.

(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.

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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

(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 three months ended March 31, 2010 as follows (in millions):

Balance, December 31, 2009	$ 3
Increases related to prior years	10
Decreases related to prior years	(9)
Increases related to current year	
Settlements	
Lapses in the statute of limitations	
Balance, March 31, 2010	$ 4

Our unrecognized federal and state tax benefits did not change significantly during the three months ended March 31, 2009.

We expect to continue discussions with taxing authorities regarding tax positions related to the following, and believe 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) $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 a 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 $60 million to $65 million (which includes an asserted tax liability of $38 million plus interest) some time during 2010 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.

(11) 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 $53 million as of March 31, 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 March 31, 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 8.

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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 March 31, 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 $12 million as of March 31, 2010. As of March 31, 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.

(12) 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 seven 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 April 2010, in a related lawsuit, the Tennessee Supreme Court reversed the Court of Appeals and dismissed all claims.

(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 2000 and 2001, we responded to the EPA s information requests related to five of our plants, and in December 2007, we received supplemental requests for two of those plants. In September 2008, we received an EPA request for information related to two additional plants and in October 2009, we received supplemental requests for those two plants. The EPA agreed to share information relating to its investigations with state environmental agencies. In January 2009, we received a Notice of Violation (NOV) from the EPA alleging that past work at our Shawville, Portland and Keystone plants violated the agency s regulations regarding New Source Review.

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 power 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.

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We believe 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 believe 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 ($18 million as of March 31, 2010 and December 31, 2009) 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 $8 million as of March 31, 2010 and December 31, 2009.
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, and related state and federal laws. In December 2009, the District Court ordered that the case be dismissed. PennEnvironment and the Sierra Club have requested that the court reconsider its ruling. 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 believe 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 October 2009, the United States Court of Appeals for the Fifth Circuit ruled that the plaintiffs claims satisfied the threshold test for standing and did not present a non-justiciable political question and remanded the case to the United States District Court for the Southern District of Mississippi for further proceedings. While we believe 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 11(a) under Pending Natural Gas Litigation.

Texas Franchise Audit. The state of Texas has issued assessment orders indicating an estimated tax liability of approximately $59 million (including interest and penalties of $21 million) relating primarily to the sourcing of receipts for 2000 through 2006. We are contesting the audit assessments related to this issue.

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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. When the final FERC order is received (currently expected in 2010), we will recognize this liability in income from continuing operations as a reduction of cost of sales.

(d) Proposed Merger with Mirant.

In April 2010, RRI Energy together with Mirant and Mirant s board of directors have been 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 defendants and their affiliates. 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 merger agreement was the product of breaches of fiduciary duties by the individual defendants, in that it allegedly does not provide for the best value reasonable under the circumstances for Mirant s public stockholders, and that the other defendants aided and abetted the individual defendants breaches of fiduciary duties. The complaints seek, among other things, (a) a declaration that the merger agreement was entered into in breach of the defendants duties, (b) to enjoin defendants from consummating the merger, (c) rescission of the merger if it is consummated and/or (d) granting the class members any profits or benefits allegedly improperly received by defendants. We believe that the allegations of the complaints are without merit and that we have substantial meritorious defenses to the claims made in these actions. See note 18.

(13) 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 2009 Form 10-K for additional information about pension and postretirement benefits.

	Pension Three months ended March 31,		Postretirement Three months ended March 31,	
	2010	2009	2010	2009
	(in millions)			
Service cost	$ 1	$ 1	$	$
Interest cost	2	2	1	2
Expected return on plan assets	(1)	(1)		
Net amortization		1		
Net periodic benefit costs	$ 2	$ 3	$ 1	$ 2

Contributions. During the three months ended March 31, 2010 and 2009, we made $0 and $1 million, respectively, in contributions to our pension plans and other postretirement benefit plans.

(14) Collective Bargaining Agreements

As of March 31, 2010, approximately 45% of our employees are subject to collective bargaining agreements. Approximately 25% of our employees are subject to collective bargaining agreements that will expire by March 31, 2011. We intend to negotiate the renewal of these agreements.

(15) 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, which are classified here as non-guarantors, will become guarantors in June 2010 related to maturity and pay off of its senior notes on May 1, 2010.

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Condensed Consolidating Statements of Operations.

	Three Months Ended March 31, 2010				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments (1)	Consolidated
Revenues	$	$ 605	$ 273	$ (273)	$ 605
Cost of sales		424	115	(272)	267
Operation and maintenance		63	99	(2)	160
General and administrative		3	18		21
Western states litigation and similar settlements		17			17
Long-lived assets impairments			248		248
Depreciation and amortization		30	32		62
Total		537	512	(274)	775
Operating income (loss)		68	(239)	1	(170)
Loss of equity investments of consolidated subsidiaries	(239)	(27)		266	
Interest expense	(33)	(6)	(7)		(46)
Interest income (expense) affiliated companies, net	21	(2)	(19)		
Other, net		2			2
Total other expense	(251)	(33)	(26)	266	(44)
Income (loss) from continuing operations before income taxes	(251)	35	(265)	267	(214)
Income tax expense (benefit)	26	33	(29)	32	62
Income (loss) from continuing operations	(277)	2	(236)	235	(276)
Income (loss) from discontinued operations		2	(3)		(1)
Net income (loss)	$ (277)	$ 4	$ (239)	$ 235	$ (277)

	Three Months Ended March 31, 2009				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments (1)	Consolidated
Revenues	$	$ 452	$ 257	$ (243)	$ 466
Cost of sales		342	223	(241)	324

Operation and maintenance		62	96	(1)	157
General and administrative		4	26	(1)	29
Gains on sales of assets and emission and exchange allowances, net		(15)	(3)		(18)
Depreciation and amortization		32	36		68
Total		425	378	(243)	560
Operating income (loss)		27	(121)		(94)
Loss of equity investments of consolidated subsidiaries	(107)	(20)		127	
Interest expense	(37)	(8)	(2)		(47)
Interest income (expense) affiliated companies, net	17	(3)	(14)		
Other, net		1			1
Total other expense	(127)	(30)	(16)	127	(46)
Loss from continuing operations before income taxes	(127)	(3)	(137)	127	(140)
Income tax expense (benefit)	8	9	(51)		(34)
Loss from continuing operations	(135)	(12)	(86)	127	(106)
Income (loss) from discontinued operations	(16)	9	(38)		(45)
Net loss	$ (151)	$ (3)	$ (124)	127	$ (151)

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

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Condensed Consolidating Balance Sheets.

	March 31, 2010				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments (1)	Consolidated
ASSETS					
Current Assets:					
Cash and cash equivalents	$ 1,082	$	$ 42	$	$ 1,124
Restricted cash		25	4		29
Accounts and notes receivable, principally customer, net	10	96	11	(3)	114
Accounts and notes receivable affiliated companies	2,414	556	175	(3,145)	
Inventory		125	168		293
Derivative assets		167	35		202
Other current assets	46	149	71	(8)	258
Current assets of discontinued operations	9	82	6	(8)	89
Total current assets	3,561	1,200	512	(3,164)	2,109
Property, Plant and Equipment, net		2,202	2,111		4,313
Other Assets:					
Other intangibles, net		48	252		300
Notes receivable affiliated companies	958	552		(1,510)	
Equity investments of consolidated subsidiaries	1,643	257	18	(1,918)	
Derivative assets		85	6		91
Other long-term assets	34	718	353	(631)	474
Long-term assets of discontinued operations		5			5
Total other assets	2,635	1,665	629	(4,059)	870
Total Assets	$ 6,196	$ 5,067	$ 3,252	$ (7,223)	$ 7,292
LIABILITIES AND EQUITY					
Current Liabilities:					
Current portion of long-term debt and short-term borrowings	$	$	$ 401	$	$ 401
Accounts payable, principally trade		63	57	(2)	118
Accounts and notes payable affiliated companies		2,270	875	(3,145)	
Derivative liabilities		68	64		132
Other current liabilities	44	248	55	(25)	322
	8	56	6	(8)	62

Current liabilities of discontinued operations					
Total current liabilities	52	2,705	1,458	(3,180)	1,035
Other Liabilities:					
Notes payable affiliated companies		966	544	(1,510)	
Derivative liabilities		4	52		56
Other long-term liabilities	586	128	129	(583)	260
Long-term liabilities of discontinued operations	2	5	7		14
Total other liabilities	588	1,103	732	(2,093)	330
Long-term Debt	1,579	371			1,950
Commitments and Contingencies					
Temporary Equity Stock-based Compensation	5				5
Total Stockholders Equity	3,972	888	1,062	(1,950)	3,972
Total Liabilities and Equity	$ 6,196	$ 5,067	$ 3,252	$ (7,223)	$ 7,292

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	December 31, 2009				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments (1)	Consolidated
ASSETS					
Current Assets:					
Cash and cash equivalents	$ 922	$	$ 26	$ (5)	$ 943
Restricted cash		17	2	5	24
Accounts and notes receivable, principally customer, net	10	129	14		153
Accounts and notes receivable affiliated companies	2,210	554	208	(2,972)	
Inventory		153	179		332
Derivative assets		100	32		132
Other current assets	48	164	88	(14)	286
Current assets of discontinued operations	129	95	5	(121)	108
Total current assets	3,319	1,212	554	(3,107)	1,978
Property, Plant and Equipment, net		2,227	2,375		4,602
Other Assets:					
Other intangibles, net		50	256		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	755	371	(650)	517
Long-term assets of discontinued operations		5			5
Total other assets	3,099	1,686	650	(4,554)	881
Total Assets	$ 6,418	$ 5,125	$ 3,579	$ (7,661)	$ 7,461
LIABILITIES AND EQUITY					
Current Liabilities:					
Current portion of long-term debt and short-term borrowings	$	$	$ 405	$	$ 405
Accounts payable, principally trade		75	68		143
Accounts and notes payable affiliated companies		2,111	861	(2,972)	
Derivative liabilities		68	84		152
Other current liabilities	10	126	50	(14)	172
Current liabilities of discontinued operations	9	162	8	(121)	58

Total current liabilities		19		2,542		1,476		(3,107)		930
Other Liabilities:										
Notes payable affiliated companies				1,062		556		(1,618)		
Derivative liabilities						61				61
Other long-term liabilities		572		138		201		(650)		261
Long-term liabilities of discontinued operations		3		7		4				14
Total other liabilities		575		1,207		822		(2,268)		336
Long-term Debt		1,579		371						1,950
Commitments and Contingencies										
Temporary Equity Stock-based Compensation		7								7
Total Stockholders Equity		4,238		1,005		1,281		(2,286)		4,238
Total Liabilities and Equity	$	6,418	$	5,125	$	3,579	$	(7,661)	$	7,461

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

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Condensed Consolidating Statements of Cash Flows.

	Three Months Ended March 31, 2010				
	RRI Energy	Guarantors	Non-Guarantors	Adjustments[1]	Consolidated
	(in millions)				
Cash Flows from Operating Activities:					
Net cash provided by continuing operations from operating activities	$ 8	$ 131	$ 37	$	$ 176
Net cash provided by discontinued operations from operating activities	10	15	1		26
Net cash provided by operating activities	18	146	38		202
Cash Flows from Investing Activities:					
Capital expenditures		(3)	(15)		(18)
Investments in, advances to and from and distributions from subsidiaries, net[2]	139			(139)	
Proceeds from sales (purchases) of emission allowances		13	(13)		
Restricted cash		(7)	(3)	5	(5)
Other, net		2			2
Net cash provided by (used in) continuing operations from investing activities	139	5	(31)	(134)	(21)
Net cash provided by (used in) discontinued operations from investing activities	1	(1)		(1)	(1)
Net cash provided by (used in) investing activities	140	4	(31)	(135)	(22)
Cash Flows from Financing Activities:					
Changes in notes with affiliated companies, net[3]		(149)	10	139	
Proceeds from issuances of stock	2				2
Net cash provided by (used in) continuing operations from financing activities	2	(149)	10	139	2
Net cash used in discontinued operations from financing activities		(1)		1	
Net cash provided by (used in) financing activities	2	(150)	10	140	2
Net Change in Cash and Cash Equivalents, Total Operations	160		17	5	182

Less: Net Change in Cash and Cash Equivalents, Discontinued Operations			1		1
Cash and Cash Equivalents at Beginning of Period, Continuing Operations	922		26	(5)	943
Cash and Cash Equivalents at End of Period, Continuing Operations	$ 1,082	$	$ 42	$	$ 1,124

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	Three Months Ended March 31, 2009				
	RRI Energy	Guarantors	Non-Guarantors	Adjustments[1]	Consolidated
			(in millions)		
Cash Flows from Operating Activities:					
Net cash provided by continuing operations from operating activities	$ 100	$ 74	$ 25	$	$ 199
Net cash provided by discontinued operations from operating activities	2	18	269		289
Net cash provided by operating activities	102	92	294		488
Cash Flows from Investing Activities:					
Capital expenditures		(5)	(50)		(55)
Investments in, advances to and from and distributions from subsidiaries, net[2]	94			(94)	
Proceeds from sales (purchases) of emission allowances		39	(32)		7
Restricted cash		(3)	(1)		(4)
Net cash provided by (used in) continuing operations from investing activities	94	31	(83)	(94)	(52)
Net cash provided by (used in) discontinued operations from investing activities	212	(8)	(226)	7	(15)
Net cash provided by (used in) investing activities	306	23	(309)	(87)	(67)
Cash Flows from Financing Activities:					
Changes in notes with affiliated companies, net[3]		(127)	33	94	
Proceeds from issuances of stock	2				2
Net cash provided by (used in) continuing operations from financing activities	2	(127)	33	94	2
Net cash provided by (used in) discontinued operations from financing activities		12	(5)	(7)	
Net cash provided by (used in) financing activities	2	(115)	28	87	2
Net Change in Cash and Cash Equivalents, Total Operations	410		13		423
			17		17

Less: Net Change in Cash and Cash Equivalents, Discontinued Operations					
Cash and Cash Equivalents at Beginning of Period, Continuing Operations	970		34		1,004
Cash and Cash Equivalents at End of Period, Continuing Operations	$ 1,380	$	$ 30	$	$ 1,410

(1) These amounts relate to either (a) eliminations and adjustments recorded in the normal consolidation process or (b) reclassifications recorded due to 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.

(16) 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.

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 believe 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 4.

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 4.

Financial data for our segments and consolidated are as follows:

	East Coal	East Gas	West	Other	Discontinued Operations	Adjustments and Eliminations	Consolidated
Three months ended March 31, 2010 (unless otherwise indicated)							
Revenues from external customers(1)	$ 287	$ 146	$ 51	$ 15		$ 106(2)	$ 605(3)
Open energy gross margin	$ 88	$	$	$			$ 88
Other margin	49	49	12	6			116
Open gross margin(4)	$ 137	$ 49	$ 12	$ 6			$ 204(5)
Long-lived assets impairments	$ 248(6)	$	$	$		$	$ 248
Total assets as of March 31, 2010	$ 3,166(7)	$ 1,292(7)	$ 172(7)	$ 611(7)	$ 94	$ 1,957(8)	$ 7,292
Three months ended March 31, 2009 (unless otherwise indicated)							
Revenues from external customers(1)	$ 272	$ 145	$ 44	$ 19		$ (14)(2)	$ 466(9)
Open energy gross margin	$ 92	$ 1	$ 1	$			$ 94
Other margin	34	38	11	13			96
Open gross margin(4)	$ 126	$ 39	$ 12	$ 13			$ 190(10)
Gains on sales of assets and emission and exchange allowances, net	$	$	$ 2	$		$ 16(11)	$ 18
Total assets as of December 31, 2009	$ 3,446(7)	$ 1,316(7)	$ 175(7)	$ 623(7)	$ 113	$ 1,788(8)	$ 7,461

(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 $282 million in revenues from a single counterparty, which represented 47% of our consolidated revenues. This counterparty is included in our East Coal and East Gas segments. As of March 31, 2010, $39 million was outstanding from this counterparty and collected in April 2010.

(4) Represents our segment profitability measure.

(5) Excludes $7 million and $127 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 $193 million and $55 million related to the Elrama and Niles plants, respectively.

(7) Primarily relates to property, plant and equipment, inventory and emission allowances. East Coal segment also includes the prepaid REMA leases of $342 million and $336 million as of March 31, 2010 and December 31, 2009, respectively. Other segment also includes our equity method investment in Sabine Cogen, LP of $19 million as of March 31, 2010 and December 31, 2009.

(8) 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.

(9) Includes $235 million in revenues from one counterparty, which represented 50% of our consolidated revenues. This counterparty is included in our East Coal and East Gas segments. Additionally, includes $54 million in revenues from a second counterparty, which represented 12% of our consolidated revenues. This counterparty is included in all of our segments.

(10) Excludes $(4) million and $(44) million of hedges and other items and unrealized losses on energy derivatives, respectively, that are included in our consolidated

revenues or cost of sales.

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

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	Three Months Ended March 31,	
	2010	2009
	(in millions)	
Open gross margin for all segments	$ 204	$ 190
Hedges and other items	7	(4)
Unrealized gains (losses) on energy derivatives	127	(44)
Operation and maintenance	(160)	(157)
General and administrative	(21)	(29)
Western states litigation and similar settlements	(17)	
Gains on sales of assets and emission and exchange allowances, net		18
Long-lived assets impairments	(248)	
Depreciation and amortization	(62)	(68)
Operating loss	(170)	(94)
Interest expense	(46)	(47)
Other, net	2(1)	1(1)
Loss from continuing operations before income taxes	$ (214)	$ (140)

(1) Includes $2 million and $1 million during the three months ended March 31, 2010 and 2009, respectively, which relates to our equity method investment in Sabine Cogen, LP, which is included in our Other segment.

(17) 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 $4 million of related interest expense during the three months ended March 31, 2009 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.

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(c) All Discontinued Operations.
The following summarizes certain financial information of the businesses reported as discontinued operations:

	Retail Energy Segment	New York Plants (in millions)	Total
Three Months Ended March 31, 2010			
Revenues	$ 1	$	$ 1
Income before income tax expense/benefit	4(1)		4
Three Months Ended March 31, 2009			
Revenues	$ 1,515	$ 2	$ 1,517
Income (loss) before income tax expense/benefit	(57)(2)	3	(54)

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

(2) Includes $224 million of unrealized gains on energy derivatives.

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

	March 31, 2010	December 31, 2009
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ 4	$ 4
Accounts receivable, net	3	6
Derivative assets	40	41
Margin deposits	41	56
Accumulated deferred income taxes, net of federal valuation allowance of $1 million and $1 million		
Other current assets	1	1
Total current assets	89	108
Other Assets:		
Derivative assets	5	5
Total long-term assets	5	5
Total Assets	$ 94	$ 113

Current Liabilities:				
Accounts payable, principally trade	$	2	$	2
Derivative liabilities		34		35
Other current liabilities		26		21
Total current liabilities		62		58
Other Liabilities:				
Derivative liabilities		5		5
Other liabilities		9		9
Total long-term liabilities		14		14
Total Liabilities	$	76	$	72

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(18) Subsequent Event

On April 11, 2010, we entered into an Agreement and Plan of Merger with Mirant, which has been unanimously approved by the boards of directors of RRI Energy and Mirant. We have formed a new wholly-owned subsidiary that will merge with and into Mirant. As a result, Mirant will be a wholly-owned subsidiary of RRI Energy.

Upon closing the merger, each issued and outstanding share of Mirant common stock, including restricted shares held 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 merger is intended to qualify as a tax-free reorganization under the Internal Revenue Code of 1986, as amended, so that 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.

Completion of the merger is contingent upon, among other things, (a) approvals by stockholders of both companies, (b) effectiveness of a registration statement on Form S-4 and approval of the New York Stock Exchange listing for the RRI Energy common stock to be issued in the merger, (c) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, (d) required regulatory approvals from the FERC and the New York Public Service Commission and (e) mutually acceptable debt financing in an amount sufficient to fund the refinancing transactions contemplated by the merger agreement.

Each of RRI Energy and Mirant is also subject to restrictions on its ability to solicit alternative acquisition proposals, provide information and engage in discussion with third parties, except under limited circumstances to permit RRI Energy s or Mirant s board of directors to comply with its fiduciary duties. The merger agreement contains termination rights for both RRI Energy and Mirant and further provides that, upon termination of the merger agreement under specified circumstances, RRI Energy or Mirant may be required to pay the other party a termination fee of either $37 million or $58 million depending on the nature of the termination.

We anticipate completing the merger before the end of 2010. Except for specific references to the pending merger, the disclosures contained in this report on Form 10-Q relate solely to RRI Energy. Information concerning the proposed merger will be included in a joint proxy statement/prospectus contained in the registration statement on Form S-4, which we will file with the Securities and Exchange Commission in connection with the merger.

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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, 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 believe 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 a flexible plant-specific operating model 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 matters and the uncertainty in the financial markets. Additionally, current commodity prices and spreads are depressed relative to historical levels. While we believe 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, capture the value of 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 believe we have the ability to operate through an extended downturn, if that should occur.

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.

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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
- 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 excellence 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

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. We plan to use 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. We plan to measure our efficiency of capturing margin utilizing total controllable costs per MWh generated and total controllable costs per MW of generation capacity. These costs metrics will include operation and maintenance expense (excluding the REMA lease expense and severance expense) and general and administrative expense (excluding severance expense) as well as maintenance capital expenditures. See these measures below under Consolidated Results of Operations.

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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. On April 11, 2010, we entered into and both our and Mirant s boards of directors had unanimously approved 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.

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.

Completion of the merger is contingent upon, among other things, (a) approvals by stockholders of both companies, (b) effectiveness of a registration statement on Form S-4 and approval of the New York Stock Exchange listing for the RRI Energy common stock to be issued in the merger, (c) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, (d) required regulatory approvals from the FERC and the New York Public Service Commission and (e) mutually acceptable debt financing in an amount sufficient to fund the refinancing transactions contemplated by the merger agreement.

We anticipate completing the merger before the end of 2010. Except for specific references to the pending merger, the disclosures contained in this report on Form 10-Q relate solely to RRI Energy. Information concerning the proposed merger will be included in a joint proxy statement/prospectus contained in the registration statement on Form S-4, which we will file with the Securities and Exchange Commission in connection with the merger. See note 18 to our interim financial statements.

Impairments of Long-Lived Assets. In March 2010, we evaluated our plants including the related intangible assets for potential impairments. We determined that two plants (Elrama and Niles) undiscounted cash flows did not exceed the carrying value of the net property, plant and equipment. Thus, we estimated each plant s fair value and determined we incurred pre-tax impairment charges of $248 million. See note 4 to our consolidated financial statements in our Form 10-K and note 6 to our interim financial statements.

Environmental Matters. For a discussion of our plans for investment to comply with other existing environmental regulations, see Business Environmental Matters in Item 1 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. For a discussion of pending and contingent matters related to environmental regulations, see note 12(b) to our interim financial statements.

Consolidated Results of Operations

Three Months Ended March 31, 2010 Compared to Three Months Ended March 31, 2009

Our loss from continuing operations before income taxes for the three months ended March 31, 2010 compared to the same period in 2009 increased by $74 million primarily due to (a) $248 million long-lived assets impairments recorded in 2010 and (b) an estimated $17 million charge for Western states litigation and similar settlements recorded in 2010. These items were partially offset by (a) $171 million net change in unrealized gains/losses on energy derivatives and (b) $14 million increase in open gross margin primarily due to RPM capacity payments and partially offset by planned and unplanned outages.

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 use these non-GAAP financial measures in communications with investors, analysts, rating agencies, banks and other parties. We believe 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 believes (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 March 31,		
	2010	2009	Change
	(millions of dollars)		
East coal open gross margin[1]	$ 137	$ 126	$ 11
East gas open gross margin[1]	49	39	10
West open gross margin[1]	12	12	
Other open gross margin[1]	6	13	(7)
Total[2]	204	190	14
Operation and maintenance, excluding severance[3][4]	(160)	(156)	(4)
General and administrative, excluding severance[4]	(21)	(29)	8
Other, net	2	1	1
Open EBITDA[2]	25	6	19
Hedges and other items[5][6]	7	(4)	11
Gains on sales of assets and emission and exchange allowances, net[7]		18	(18)
Adjusted EBITDA[2]	32	20	12
Unrealized gains (losses) on energy derivatives[6][8]	127	(44)	171
Western states litigation and similar settlements[9]	(17)		(17)
Severance[10]		(1)	1
Long-lived assets impairments[11]	(248)		(248)
EBITDA[2]	(106)	(25)	(81)

Depreciation and amortization		(62)		(68)		6
Interest expense, net		(46)		(47)		1
Loss from continuing operations before income taxes		(214)		(140)		(74)
Income tax (expense) benefit		(62)		34		(96)
Loss from continuing operations		(276)		(106)		(170)
Loss from discontinued operations		(1)		(45)		44
Net loss	$	(277)	$	(151)	$	(126)

(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 believe 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) Described below under Hedges and Other Items.

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(6) 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.

(7) 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 believe 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.

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

(9) We exclude charges related to settlement of actions in our legacy Western states and similar matters.

(10) Includes severance classified in operation and maintenance expense.

(11) Impairment charges are related to our Elrama and Niles long-lived assets totaling $248 million. See note 6 to our interim financial statements.

	Three Months Ended March 31,		
	2010	2009	Change
Diluted Loss per Share			
Loss from continuing operations	$ (0.78)	$ (0.30)	$ (0.48)
Loss from discontinued operations		(0.13)	0.13
Net loss	$ (0.78)	$ (0.43)	$ (0.35)

Operational and Financial Data.

Segment	Generation (GWh) (1) Three Months Ended March 31, 2010	2009	Open Energy Unit Margin ($/MWh) (2) Three Months Ended March 31, 2010	2009	Total Margin Capture Factor (3) Three Months Ended March 31, 2010	2009
East Coal	5,373.3	5,085.8	$ 16.38	$ 18.09	79.1%	82.5%
East Gas	92.6	156.4	NM(4)	6.39	91.7	92.1
West	21.2	128.2		7.80	79.1	81.5
Other					NM(4)	NM(4)
Total	5,487.1	5,370.4	$ 16.04	$ 17.50	82.4%	85.2%

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

(4) NM is not meaningful.

Revenues.

	Three Months Ended March 31, 2010	2009	Change
	(in millions)		
Third-party revenues	$ 499	$ 470	$ 29(1)
Unrealized gains (losses) on energy derivatives	106	(4)	110(2)
Total revenues	$ 605	$ 466	$ 139

(1) Increase primarily due to higher RPM capacity payments. RPM is the model utilized by the PJM Interconnection, LLC to meet load serving entities forecasted capacity obligations via a forward-looking commitment of capacity resources.

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

Cost of Sales.

	Three Months Ended March 31, 2010	2009	Change
	(in millions)		
Third-party costs	$ 288	$ 284	$ 4
Unrealized (gains) losses on energy derivatives	(21)	40	(61)(1)
Total cost of sales	$ 267	$ 324	$ (57)

(1)

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 March 31, 2010	2009	Change
		(in millions)	
East Coal			
Open energy gross margin	$ 88	$ 92	$ (4)
Other margin	49	34	15(1)
Open gross margin	$ 137	$ 126	$ 11
East Gas			
Open energy gross margin	$	$ 1	$ (1)
Other margin	49	38	11(1)
Open gross margin	$ 49	$ 39	$ 10
West			
Open energy gross margin	$	$ 1	$ (1)
Other margin	12	11	1
Open gross margin	$ 12	$ 12	$
Other			
Open energy gross margin	$	$	$
Other margin	6	13	(7)(2)
Open gross margin	$ 6	$ 13	$ (7)
Total			
Open energy gross margin(3)	$ 88	$ 94	$ (6)
Other margin(3)	116	96	20
Open gross margin(3)	$ 204	$ 190	$ 14

(1)

Increase primarily due to RPM capacity payments.

(2) Decrease primarily due to the expiration of a power purchase agreement in December 2009.

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

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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 3, 4 and 16 to our interim financial statements for further discussion. The analyses of these items are included below.

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 March 31,		
	2010	2009	Change
	(in millions)		
Power	$ (6)	$ (10)	$ 4
Fuel	(5)	(53)	48(1)
Tolling/other	18	59	(41)(2)
Hedges and other items income (loss)	$ 7	$ (4)	$ 11

(1) Increase primarily due to (a) $25 million of additional costs incurred in 2009 to reduce fixed price coal commitments for future periods and improved results of fuel hedges in 2010 as compared to 2009 in our East Coal segment and (b) $22 million lower market valuation adjustments to fuel inventory due to $2 million in losses in 2010

and $24 million in losses in 2009 in our East Coal segment.

(2) Decrease primarily due to (a) $27 million decline in results of gas transportation hedges and (b) $17 million decline in results of hedges of generation.

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 March 31, 2010	2009	Change
		(in millions)	
Revenues unrealized	$ 106	$ (4)	$ 110
Cost of sales unrealized	21	(40)	61
Net unrealized gains (losses) on energy derivatives	$ 127	$ (44)	$ 171(1)

(1) Net change primarily due to $146 million in gains from changes in prices on our energy derivatives marked to market and $25 million in gains due to the reversal of

previously recognized unrealized losses on our energy derivatives which settled during the period.

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Operation and Maintenance.

	Three Months Ended March 31, 2010	2009	Change
	(in millions)		
Plant operation and maintenance	$ 121	$ 115	$ 6(1)
REMA leases	15	15	
Taxes other than income and insurance	11	11	
Information Technology, Risk and other salaries and benefits	8	7	1
Commercial Operations	3	5	(2)
Severance		1	(1)
Other, net	2	3	(1)
Operation and maintenance	$ 160	$ 157	$ 3

(1) Increase primarily due to $12 million increase in planned outages and project spending primarily in the East Coal segment. This increase was partially offset by (a) $3 million decrease in base O&M due to decreased operations attributable to the use of our plant-specific operating model and cost reduction initiatives primarily in our East Coal and West segments and (b) $3 million decrease in

services and support due to cost reduction initiatives.

General and Administrative.

	Three Months Ended March 31, 2010	2009	Change
	(in millions)		
Salaries and benefits	$ 12	$ 17	$ (5)
Professional fees, contract services and information systems maintenance	4	6	(2)
Rent and utilities	3	4	(1)
Other, net	2	2	
General and administrative	$ 21	$ 29	$ (8)

Efficiency Measures Total Controllable Costs.

	Three Months Ended March 31, 2010	2009	Change
	(dollars in millions, except per MWh and per MW data)		
Operation and maintenance, excluding severance[1]	$ 160	$ 156	$ 4
REMA lease expense	(15)	(15)	
General and administrative, excluding severance[1]	21	29	(8)
Maintenance capital expenditures	6	19	(13)
Total Controllable Costs	$ 172	$ 189	$ (17)
TWh generation	5.5	5.4	0.1
Total Controllable Costs/MWh	$ 31	$ 35	$ (4)
MW capacity [2]	14,581	14,580	1
Total Controllable Costs ($ thousands)/MW capacity	$ 11.8	$ 13.0	$ (1.2)

(1) Excludes 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. During the three months ended March 31, 2010 and 2009, there were no severance charges included in general and administrative.

(2) MW capacity changed from March 31, 2009 to March 31, 2010 due to MW re-ratings that occurred during the second and fourth quarters of 2009.

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Total Controllable Costs Reconciliation. We believe the measures of total controllable costs per MWh generated and total controllable costs per MW 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. 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 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.

	Three Months Ended March 31,		
	2010	2009	Change
	(dollars in millions, except per MWh and per MW data)		
Operation and maintenance (O&M)	$ 160	$ 157	$ 3
General and administrative (G&A)	21	29	(8)
Capital expenditures	18	55	(37)
Total operation and maintenance, general and administrative and capital expenditures	$ 199	$ 241	$ (42)
Total Controllable Costs	$ 172	$ 189	$ (17)
REMA lease expense in operation and maintenance	15	15	
Severance included in operation and maintenance		1	(1)
Environmental capital expenditures	10	29	(19)
Capitalized interest	2	7	(5)
Total operation and maintenance, general and administrative and capital expenditures	$ 199	$ 241	$ (42)
TWh generation	5.5	5.4	0.1
Total O&M, G&A and capital expenditure/MWh	$ 36	$ 45	$ (9)
MW capacity [1]	14,581	14,580	1
Total O&M, G&A and capital expenditures ($thousands)/MW capacity	$ 13.6	$ 16.5	$ (2.9)

(1) MW capacity changed from

March 31, 2009 to March 31, 2010 due to MW re-ratings that occurred during the second and fourth quarters of 2009.

Western States Litigation and Similar Settlements. See note 11 to our interim financial statements.

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

	Three Months Ended March 31,		
	2010	2009	Change
		(in millions)	
CO_2 exchange allowances	$	$ 10	$ (10)
SO_2 and NO_x emission allowances		7	(7)
Other, net		1	(1)
Gains on sales of assets and emission and exchange allowances, net	$	$ 18	$ (18)

Long-lived Assets Impairments. See note 6 to our interim financial statements.

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Depreciation and Amortization.

	Three Months Ended March 31, 2010	2009 (in millions)	Change
Depreciation on plants	$ 54	$ 55	$ (1)
Other, net depreciation	3	4	(1)
Depreciation	57	59	(2)
Amortization of emission allowances	4	8	(4)[(1)]
Other, net amortization	1	1	
Amortization	5	9	(4)
Depreciation and amortization	$ 62	$ 68	$ (6)

(1) Decrease primarily due to lower weighted average cost of SO_2 allowances, partially offset by an increase in SO_2 allowances used.

Interest Expense.

	Three Months Ended March 31, 2010	2009 (in millions)	Change
Fixed-rate debt	$ 48	$ 53	$ (5)
Deferred financing costs	2	2	
Financing fees expensed	2	2	
Capitalized interest	(2)[(1)]	(7)[(2)]	5
Amortization of fair value adjustment of acquired debt	(4)	(3)	(1)
Interest expense	$ 46	$ 47	$ (1)

(1) Relates primarily to environmental

capital expenditures for SO_2 emission reductions at our Cheswick plant.

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

Other, Net. Other, net did not change significantly.

Income Tax Expense (Benefit). See note 10 to our interim financial statements. A reconciliation of the federal statutory income tax rate to the effective income tax rate is:

	Three Months Ended March 31,	
	2010	**2009**
Federal statutory rate	(35)%	(35)%
Additions (reductions) resulting from:		
Federal valuation allowance	52(1)	11(2)
State income taxes, net of federal income taxes	10(3)	(1)(4)
Other	2	1
Effective rate	29%	(24)%

(1) Of this percentage, $112 million (52%) relates to additional valuation allowance.

(2) Of this percentage, $16 million (11%) relates to additional valuation allowance.

(3) Of this percentage, $32 million (15%) relates to additional valuation allowances.

(4) Of this percentage, $6 million (4%) relates to additional valuation allowances.

Loss from Discontinued Operations. See note 17 to our interim financial statements.

Liquidity and Capital Resources

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 believe our liquidity has and continues to exceed the level required to achieve this goal. As of May 3, 2010 (after paying off our Orion Power senior notes of $400 million), we had total available liquidity of $1.3 billion, comprised of cash and cash equivalents ($676 million), unused borrowing capacity ($500 million) and letters of credit capacity ($163 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. As of March 31, 2010, we had gross debt of $2.8 billion and GAAP debt of $2.4 billion. The comparable target for total GAAP debt, based on the current balance for our REMA leases of $423 million, is approximately $800 million to $1.3 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 believe 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 three months ended March 31, 2010, we generated $176 million in operating cash flows from continuing operations, including the net changes in margin deposits of $97 million (cash inflow). See Historical Cash Flows for further detail of our cash flows from operating activities and explanation of our $21 million and $2 million use of cash from investing activities from continuing operations and generation of cash from financing activities from continuing operations, respectively, during the three months ended March 31, 2010.

See note 10 to our interim financial statements regarding an expected income tax cash payment of approximately $60 to $65 million relating to California-related matters in 2010.

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 32% and 31% 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 3% and 9% of this estimated power generation for 2010 and 2011, respectively, with financial options to retain the energy margin upside for market improvements.

Non-GAAP Cash Flows Measures.

	Three Months Ended March 31,			
	2010		2009	
	(in millions)			
Operating cash flow from continuing operations	$	176	$	199
Change in margin deposits, net[1]		(97)		(106)
Adjusted cash flow provided by continuing operations		79		93
Capital expenditures		(18)		(55)
Proceeds from sales of emission and exchange allowances[2]				12
Purchases of emission allowances[2]				(5)
Free cash flow provided by continuing operations	$	61	$	45

(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 believe 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 that is available to us for discretionary expenditures, since they may not include deductions for all non-discretionary expenditures. We believe, however, that our non-GAAP cash flow measures are useful because they provide a representation of our cash level 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 5 to our interim financial statements.

Off-Balance Sheet Arrangements

As of March 31, 2010, we have no off-balance sheet arrangements.

Historical Cash Flows

Cash Flows Operating Activities

	Three Months Ended March 31, 2010	2009	Change
	(in millions)		
Operating loss	$ (170)	$ (94)	$ (76)
Depreciation and amortization	62	68	(6)
Western states litigation and similar settlements	17		17
Gains on sales of assets and emission allowances, net		(18)	18
Long-lived assets impairments	248		248
Net changes in energy derivatives	(126) [(1)]	44 [(2)]	(170)
Margin deposits, net	97	106	(9)
Change in accounts and notes receivable and accounts payable, net	15	89	(74)
Change in inventory	39	21	18
Settlements of exchange transactions prior to contractual period[(3)]	1	(10)	11
Interest payments, net of capitalized interest	1	5	(4)
Income tax payments, net of refunds		(4)	4
Prepaid lease obligation	(5)	(6)	1
Other, net	(3)	(2)	(1)
Net cash provided by continuing operations from operating activities	176	199	(23)
Net cash provided by discontinued operations from operating activities	26	289	(263)
Net cash provided by operating activities	$ 202	$ 488	$ (286)

(1) Includes unrealized gains

on energy derivatives of $127 million.

(2) Includes unrealized losses on energy derivatives of $44 million.

(3) Represents exchange transactions financially settled within three business days prior to the contractual delivery month.

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Cash Flows Investing Activities

	Three Months Ended March 31, 2010		2009		Change
	(in millions)				
Capital expenditures	$	(18)	$	(55)	$	37(1)
Proceeds from sales of emission allowances				12		(12)
Purchases of emission allowances				(5)		5
Restricted cash		(5)		(4)		(1)
Other, net		2				2
Net cash used in continuing operations from investing activities		(21)		(52)		31
Net cash used in discontinued operations from investing activities		(1)		(15)		14
Net cash used in investing activities	$	(22)	$	(67)	$	45

(1) Decrease primarily due to (a) $24 million decrease in environmental capital expenditures (including capitalized interest) for SO_2 emission reductions at our Cheswick and Keystone plants, which are included in our East Coal segment (the scrubber project for our Keystone plant was completed in 2009, the scrubber project for our Cheswick plant was halted in mid-2009 and resumed in 2010) and (b)

$13 million decrease in maintenance capital expenditures.

Cash Flows Financing Activities

	Three Months Ended March 31,		
	2010	2009	Change
		(in millions)	
Proceeds from issuances of stock	$ 2	$ 2	$
Net cash provided by financing activities	$ 2	$ 2	$

New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates

New Accounting Pronouncements

See notes 1 and 3 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 6 to our interim financial statements for further discussion regarding 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, we had three additional plants and related intangible assets with a combined carrying value of $344 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 three plants (and possibly others) could be impaired.

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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 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 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 two plants for which we recorded an impairment during the three months ended March 31, 2010 that could be materially greater than or less than the fair value estimates as of March 31, 2010. Any future fair value estimates for our Elrama and Niles long-lived assets that are greater than the fair value estimates as of March 31, 2010 will not result in reversal of the first quarter 2010 impairment charges.

The undiscounted cash flow scenarios we considered in assessing the recoverability of our long-lived assets are those which we believe 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, which would have necessitated fair value estimates for those plants. Alternatively, if we had solely utilized the 5-year market forecast with fundamental view, the carrying value of only one plant and related intangible assets ($108 million) would have been greater than the undiscounted future cash flows, which would have necessitated fair value estimates for that plant.

The discounted cash flow scenarios we considered in determining the fair values of our Elrama and Niles long-lived assets are those which we believe 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 3 and 4 to our interim financial statements.

Non-Trading Market Risks

Commodity Price Risk

As of March 31, 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 March 31, 2011	Remainder of 2011	2012	2013	2014	2015 and thereafter	Total fair value
				(in millions)			
Prices actively quoted (Level 1)	$ 76	$ 63	$	$	$	$	$ 139
Prices provided by other external sources (Level 2)	(32)	(22)	(13)				(67)
Prices based on models and other valuation methods (Level 3)	12	7					19
Total mark-to-market non-trading derivatives	$ 56	$ 48	$ (13)	$	$	$	$ 91

The fair values shown in the table above are subject to significant changes due to 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 3 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)	
March 31, 2010	10% increase	$ (20)	$ (20)
December 31, 2009	10% increase	(47)	(47)

Interest Rate Risk

As of March 31, 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 three months ended March 31, 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 March 31, 2010 and December 31, 2009 levels, the fair values of our fixed rate debt from continuing operations would have increased by $116 million and $126 million, respectively.

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Trading Market Risks

As of March 31, 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 March 31, 2011	Remainder of 2011	2012	2013 (in millions)	2014	2015 and thereafter	Total fair value
Prices actively quoted (Level 1)	$ 17	$	$	$	$	$	$ 17
Prices provided by other external sources (Level 2)							
Prices based on models and other valuation methods (Level 3)	(3)						(3)
Total	$ 14	$	$	$	$	$	$ 14

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 March 31, 2010 (in millions)	Three Months Ended March 31, 2009
Realized	$ 6	$ 11
Unrealized	(5)	
Total	$ 1	$ 11

An analysis of these net derivative assets and liabilities is:

	Three Months Ended March 31, 2010 (in millions)	Three Months Ended March 31, 2009
Fair value of contracts outstanding, beginning of period	$ 19	$ 30
Contracts realized or settled	(6) [(1)]	(12)[(2)]
Changes in fair values attributable to market price and other market changes	1	12
Fair value of contracts outstanding, end of period	$ 14	$ 30

(1) Amount includes realized gain of $6 million.

(2) Amount includes realized gain of $11 million and deferred settlements of $1 million.

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

	2010[1]	2009
	(in millions)	
As of March 31	$	$ 3
Three months ended March 31:		
Average		3
High	1	4
Low		2

(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 believe 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 3 and 4 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 March 31, 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 March 31, 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 March 31, 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 12 to our interim financial statements in this Form 10-Q.

ITEM 1A. RISK FACTORS

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 arrangement of mutually acceptable debt financing, obtaining stockholder approval in connection with the proposed transaction, receipt of approvals from the FERC and the New York Public Service Commission and expiration or termination of the applicable Hart-Scott-Rodino Act waiting period. Obtaining the financing is dependent on numerous factors, including capital market conditions, credit availability from financial institutions and both parties financial performance. Furthermore, purported class actions have been brought on behalf of holders of Mirant common stock. If these actions or similar actions that may be brought are successful, the merger could be delayed or prevented. See note 12(d) to our interim financial statements for discussion of pending litigation related to the merger.

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Satisfying the conditions to and completion of the merger may take longer than expected and could cost more than we expect. We cannot make any assurances that we will be able to satisfy all the conditions to the merger or succeed in any litigation brought in connection with 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:

- under circumstances specified in the merger agreement, we may be required to pay Mirant a termination fee of either $37 million or $58 million depending on the nature of the termination
- 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
- 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. Failure to achieve these anticipated benefits could result in increased costs and decreases in the amount of expected revenues generated by the combined company.

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)

May 6, 2010

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

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INDEX OF EXHIBITS

The exhibits with the cross symbol (+) are filed with the Form 10-Q. The exhibits with the asterisk symbol (*) are compensatory arrangements filed pursuant to Item 601(b)(10)(iii) of Regulation S-K. 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	2002 Long Term Incentive Plan Form of 2010 Long Term Incentive Award Agreement for Officers			
+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