RRI ENERGY INC
Form 10-Q
November 05, 2009

Table of Contents

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

(Mark One)

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

For the quarterly period ended September 30, 2009

OR

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

For the transition period from _____ to _____

Commission file number 1-16455

RRI Energy, Inc.
(Exact Name of Registrant as Specified in Its Charter)

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

1000 Main Street
Houston, Texas 77002
(Address of Principal Executive Offices) (Zip Code)
(832) 357-3000
(Registrant s Telephone Number, Including Area Code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes þ No o

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

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

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

As of October 27, 2009, the latest practicable date for determination, RRI Energy, Inc. had 352,778,305 shares of common stock outstanding and no shares of treasury stock.

TABLE OF CONTENTS

PART II.
OTHER INFORMATION

Table of Contents

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 our view 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, purchased power and fuel and emission allowances;
- Limitations on our ability to set rates at market prices;
- Legislative, regulatory and/or market developments;
- Our ability to obtain adequate fuel supply and/or transmission and distribution services;
- Interruption or breakdown of our generating equipment and processes;
- Failure of third parties to perform contractual obligations;
- Changes in environmental regulations that constrain our operations or increase our compliance costs;
- Failure by transmission system operators to communicate operating and system information properly and timely;
- Failure to meet our debt service, restrictive covenants or collateral postings;
- Ineffective hedging and other risk management activities;
- Changes in the wholesale energy market or in our evaluation of our generation assets;
- The outcome of pending or threatened lawsuits, regulatory proceedings, tax proceedings and investigations;
- Weather-related events or other events beyond our control;
- The timing and extent of changes in commodity prices or interest rates; and
- Financial and economic market conditions and our access to capital.

Other factors that could cause our actual results to differ from our projected results are discussed or referred to in the Risk Factors section 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.

Table of Contents

PART I.
FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
	(thousands of dollars, except per share amounts)			
Revenues:				
Revenues (including $25,095, $6,169, $51,255 and $12,906 unrealized losses) (including $0, $0, $0 and $253,001 from affiliates)	$ 507,179	$ 959,865	$ 1,363,140	$ 2,853,227
Expenses:				
Cost of sales (including $31,826, $(34,247), $20,857 and $70,806 unrealized gains (losses)) (including $0, $1,234, $0 and $71,540 from affiliates)	267,632	513,801	872,373	1,591,516
Operation and maintenance	114,457	134,586	428,567	455,764
General and administrative	23,686	23,070	80,345	84,911
Western states litigation and similar settlements		3,467		37,467
Gains on sales of assets and emission and exchange allowances, net	(1,013)	(16,561)	(21,184)	(39,484)
Depreciation and amortization	67,724	78,353	203,228	244,059
Total operating expense	472,486	736,716	1,563,329	2,374,233
Operating Income (Loss)	34,693	223,149	(200,189)	478,994
Other Income (Expense):				
Income of equity investment, net	1,297	1,405	1,148	2,600
Debt extinguishments gains (losses)	(103)	(904)	741	(2,257)
Other, net	(417)	4,593	(206)	4,619
Interest expense	(44,614)	(49,293)	(136,600)	(151,803)
Interest income	407	4,495	1,376	19,146
Total other expense	(43,430)	(39,704)	(133,541)	(127,695)
Income (Loss) from Continuing Operations Before Income Taxes	(8,737)	183,445	(333,730)	351,299
Income tax expense (benefit)	9,532	89,868	(105,988)	162,808
Income (Loss) from Continuing Operations	(18,269)	93,577	(227,742)	188,491

Income (loss) from discontinued operations	2,841	(1,131,497)	864,467	(490,511)
Net Income (Loss)	$ (15,428)	$ (1,037,920)	$ 636,725	$ (302,020)
Basic Earnings (Loss) per Share:				
Income (loss) from continuing operations	$ (0.05)	$ 0.27	$ (0.65)	$ 0.54
Income (loss) from discontinued operations	0.01	(3.24)	2.46	(1.41)
Net income (loss)	$ (0.04)	$ (2.97)	$ 1.81	$ (0.87)
Diluted Earnings (Loss) per Share:				
Income (loss) from continuing operations	$ (0.05)	$ 0.26	$ (0.65)	$ 0.53
Income (loss) from discontinued operations	0.01	(3.19)	2.46	(1.38)
Net income (loss)	$ (0.04)	$ (2.93)	$ 1.81	$ (0.85)

See Notes to our Unaudited Consolidated Interim Financial Statements

Table of Contents

RRI ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2009	December 31, 2008
	(thousands of dollars, except per share amounts)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,254,070	$ 1,004,367
Restricted cash	3,473	2,721
Accounts and notes receivable, principally customer	145,266	249,871
Inventory	317,993	314,999
Derivative assets	150,302	161,340
Margin deposits	184,117	32,676
Investment in and receivables from Channelview, net	24,271	58,703
Prepayments and other current assets	94,688	124,449
Current assets of discontinued operations ($87,990 and $295,477 of margin deposits)	161,925	2,506,340
Total current assets	2,336,105	4,455,466
Property, plant and equipment, gross	6,544,219	6,417,268
Accumulated depreciation	(1,773,491)	(1,597,479)
Property, Plant and Equipment, net	4,770,728	4,819,789
Other Assets:		
Other intangibles, net	370,014	380,554
Derivative assets	62,926	78,879
Prepaid lease	292,127	273,374
Other ($33,264 and $29,012 accounted for at fair value)	238,028	219,552
Long-term assets of discontinued operations	10,343	494,781
Total other assets	973,438	1,447,140
Total Assets	$ 8,080,271	$ 10,722,395
LIABILITIES AND EQUITY		
Current Liabilities:		
Current portion of long-term debt and short-term borrowings	$ 568,420	$ 12,517
Accounts payable, principally trade	134,583	156,604
Derivative liabilities	215,727	202,206
Margin deposits	4,538	93,000
Other	240,367	199,026
Current liabilities of discontinued operations ($8,750 and $0 of margin deposits)	71,659	2,375,895

Total current liabilities		1,235,294		3,039,248
Other Liabilities:				
Derivative liabilities		87,637		140,493
Other		296,612		272,079
Long-term liabilities of discontinued operations		19,483		873,190
Total other liabilities		403,732		1,285,762
Long-term Debt		1,984,792		2,610,737
Commitments and Contingencies				
Temporary Equity Stock-based Compensation		5,765		9,004
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; 352,757,922 and 349,812,537 issued)		114		111
Additional paid-in capital		6,257,995		6,238,639
Accumulated deficit		(1,738,476)		(2,375,201)
Accumulated other comprehensive loss		(68,945)		(85,905)
Total stockholders equity		4,450,688		3,777,644
Total Liabilities and Equity	$	8,080,271	$	10,722,395

See Notes to our Unaudited Consolidated Interim Financial Statements

Table of Contents

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

	Nine Months Ended September 30, 2009	2008
	(thousands of dollars)	
Cash Flows from Operating Activities:		
Net income (loss)	$ 636,725	$ (302,020)
(Income) loss from discontinued operations	(864,467)	490,511
Net income (loss) from continuing operations	(227,742)	188,491
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	203,228	244,059
Deferred income taxes	(106,923)	136,909
Net changes in energy derivatives	30,748	(57,900)
Amortization of deferred financing costs	6,459	4,949
Gains on sales of assets and emission and exchange allowances, net	(21,184)	(39,484)
Western states litigation and similar settlements		37,467
Other, net	(2,446)	(2,158)
Changes in other assets and liabilities:		
Accounts and notes receivable, net	117,255	17,133
Changes in notes, receivables and payables with affiliate, net	68	4,183
Inventory	(1,399)	(42,484)
Margin deposits, net	(239,903)	28,944
Net derivative assets and liabilities	(26,816)	(5,550)
Western states litigation and similar settlements payments	(3,449)	
Accounts payable	(9,111)	(53,185)
Other current assets	7,749	(800)
Other assets	(19,858)	(4,774)
Taxes payable/receivable	(3,479)	24,034
Other current liabilities	36,779	33,905
Other liabilities	(15,719)	(8,246)
Net cash provided by (used in) continuing operations from operating activities	(275,743)	505,493
Net cash provided by (used in) discontinued operations from operating activities	534,275	(237,392)
Net cash provided by operating activities	258,532	268,101
Cash Flows from Investing Activities:		
Capital expenditures	(157,750)	(191,059)
Proceeds from sales of assets, net	35,931	18,429
Proceeds from sales of emission and exchange allowances	19,180	38,685
Purchases of emission allowances	(7,624)	(26,053)
Restricted cash	(752)	(2,705)
Other, net	3,750	3,312

Net cash used in continuing operations from investing activities		(107,265)		(159,391)
Net cash provided by (used in) discontinued operations from investing activities		313,775		(24,636)
Net cash provided by (used in) investing activities		206,510		(184,027)
Cash Flows from Financing Activities:				
Payments of long-term debt		(59,413)		(57,704)
Payments of debt extinguishments expenses				(1,017)
Proceeds from issuances of stock		4,584		13,542
Net cash used in continuing operations from financing activities		(54,829)		(45,179)
Net cash used in discontinued operations from financing activities		(260,707)		
Net cash used in financing activities		(315,536)		(45,179)
Net Change in Cash and Cash Equivalents, Total Operations		149,506		38,895
Less: Net Change in Cash and Cash Equivalents, Discontinued Operations		(100,197)		(90,596)
Cash and Cash Equivalents at Beginning of Period, Continuing Operations		1,004,367		524,070
Cash and Cash Equivalents at End of Period, Continuing Operations	$	1,254,070	$	653,561
Supplemental Disclosure of Cash Flow Information:				
Cash Payments:				
Interest paid (net of amounts capitalized) for continuing operations	$	89,127	$	103,459
Income taxes paid (net of income tax refunds) for continuing operations		4,582		1,864

See Notes to our Unaudited Consolidated Interim Financial Statements

Table of Contents

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 electricity, capacity, ancillary and other energy services to wholesale customers in competitive power generation 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 15. 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.

On May 1, 2009, we sold our interests in the affiliates that operated our Texas retail business; we began reporting this business as discontinued operations in the first quarter of 2009. In connection with this sale, we changed our name to RRI Energy, Inc. from Reliant Energy, Inc. effective May 2, 2009. See note 17.

(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; and
- 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. We have evaluated subsequent events for recording and disclosure to November 5, 2009, the date the interim financial statements were issued.

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. We have reclassified certain amounts reported in these interim financial statements from prior periods to conform to the 2009 presentation. These reclassifications had no impact on reported earnings/losses.

Deconsolidation of Channelview. On August 20, 2007, four of our wholly-owned subsidiaries, RRI Energy Channelview LP, RRI Energy Channelview (Texas) LLC, RRI Energy Channelview (Delaware) LLC and RRI Energy Services Channelview LLC (collectively, Channelview), filed for reorganization under Chapter 11 of the Bankruptcy Code. As Channelview was subject to the supervision of the bankruptcy court, we deconsolidated Channelview s financial results beginning August 20, 2007 and began reporting our investment in Channelview using the cost method. The Channelview plant was sold on July 1, 2008. Channelview emerged from bankruptcy in October 2009. See note 16 for further discussion of Channelview.

Inventory. We value fuel inventories at the lower of average cost or market. We reduce these inventories as they are used in the production of electricity or sold. We recorded $23 million and $14 million during the three months ended September 30, 2009 and 2008, respectively, for lower of average cost or market adjustments in cost of sales and recorded $82 million and $15 million during the nine months ended September 30, 2009 and 2008, respectively.

Review for Asset Impairments. In connection with the decline in current market conditions, we evaluated each of our plants and related intangible assets for potential impairments as of September 30, 2009. The impairment evaluations considered a variety of scenarios and were performed to assess whether the carrying values of these assets were recoverable. Although near-term energy market conditions have deteriorated since mid-2008, in part reflecting lower commodity prices, decreased demand and a compression of dark spreads, our evaluations indicated that the estimated undiscounted future cash flows exceeded the carrying values of the plants and related intangible assets and impairments did not exist as of September 30, 2009 under the held and used model. However, compared to historical levels, the amount of excess plant-level undiscounted cash flows has been significantly reduced.

FASB Codification. The Financial Accounting Standards Board s (FASB) Accounting Standards Codification became effective for us in the third quarter of 2009. The Codification brings together in one place all authoritative GAAP except for rules, regulations and interpretative releases of the Securities and Exchange Commission which are also authoritative GAAP for us. This change did not materially affect our consolidated financial statements.

New Accounting Pronouncement Not Yet Adopted Disclosures about Plan Assets. Effective for our 2009 Annual Report on Form 10-K, we will provide (a) enhanced disclosures regarding investment policies and strategies for our benefit plan assets and (b) information about fair value measurements of plan assets similar to the required disclosures about other fair value measurements as disclosed in note 3.

(2) Stock-based Compensation

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Stock-based incentive plans compensation expense (income) (pre-tax)[(1)]	$ 3	$ (1)	$ 7	$ 7

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

During June 2009, the compensation committee of our board of directors granted 817,030 time-based restricted stock units and 817,030 time-based cash units to employees under our stock and incentive plans. The awards will vest in June 2012. No tax benefits related to stock-based compensation were realized during the three and nine months ended September 30, 2009 and 2008 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 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. 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. It also includes our available-for-sale and trading securities.

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.

Table of Contents

We value some of our OTC, complex or structured derivative instruments using valuation models, which utilize inputs that may not be corroborated by market data, 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.

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 are as follows:

	September 30, 2009				
	Level 1	Level 2	Level 3 (in millions)	Reclassifications[1]	Total Fair Value
Total derivative assets	$ 150	$ 59	$ 5	$ (1)	$ 213
Total derivative liabilities	60	162	82	(1)	303
Other assets[2]	33				33

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

(2) Includes $12 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).

	December 31, 2008				
	Level 1	Level 2	Level 3 (in millions)	Reclassifications(1)	Total Fair Value
Total derivative assets	$ 125	$ 111	$ 7	$ (3)	$ 240
Total derivative liabilities	17	208	121	(3)	343
Other assets(2)	29				29

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

(2) Includes $8 million in available-for-sale securities (shares in a public exchange) and $21 million in trading securities (rabbi trust investments (which is comprised of mutual funds) associated with our non-qualified deferred compensation plans for key and highly compensated employees).

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	Net Derivatives (Level 3)		Net Derivatives (Level 3)	
	(in millions)			
Balance, beginning of period	$ (117)	$ 176	$ (114)	$ 21
Total gains (losses) realized/unrealized:				
Included in earnings[1]	(7)	(37)	(78)	141
Purchases, issuances and settlements (net)	47	(58)	115	(81)
Transfers in and/or out of Level 3 (net)				
Balance, end of period	$ (77)	$ 81	$ (77)	$ 81
Changes in unrealized gains (losses) relating to derivative assets and liabilities still held at September 30, 2009 and 2008:				
Revenues	$	$ 2	$ (1)	$ 2
Cost of sales	(6)	(43)	(41)	43
Total	$ (6)	$ (41)	$ (42)	$ 45

(1) Recorded in revenues and cost of sales.

Fair Value of Other Financial Instruments. The fair values of cash and cash equivalents, accounts receivable and payable, margin deposits, available-for-sale securities, trading securities and derivative assets and liabilities approximate their carrying amounts. Values of our debt for continuing operations (see note 7) are:

	September 30, 2009		December 31, 2008	
	Carrying Value	Fair Value[1]	Carrying Value	Fair Value[1]
	(in millions)			
Fixed rate debt	$ 2,553	$ 2,555	$ 2,623	$ 2,168
Total debt	$ 2,553	$ 2,555	$ 2,623	$ 2,168

(1) We based the fair values of our fixed rate debt on market

prices and quotes from an investment bank.

See note 2(e) to our consolidated financial statements in our Form 10-K for additional information about fair value measurements.

(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, based on our assessment of (a) operational and market limitations requiring us to enter into power, fuel, capacity and emissions transactions to manage our generation assets, (b) the near term economic environment and volatile commodity markets and the benefits of hedging some of the downside risk to our earnings and cash flows and (c) market fundamentals and the opportunity to increase the return from our generation assets. 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. The fair values of our derivative activities are determined by (a) prices actively quoted, (b) prices provided by other external sources or (c) prices based on models and other valuation methods. See note 3 for discussion on fair value measurements.

Table of Contents

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.

(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 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 some contracts receiving accrual accounting treatment while related derivative instruments are marked to market through earnings. As discussed in note 1(b), our financial statements include estimates and assumptions made by management throughout the reporting periods and as of the balance sheet dates. It is reasonable that subsequent to the balance sheet date of September 30, 2009, 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 but during the current reporting period.

Cash Flow Hedges. During the first quarter of 2007, we de-designated our remaining cash flow hedges; therefore, as of September 30, 2009 and December 31, 2008, 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 income/loss into earnings. Amounts included in accumulated other comprehensive loss are:

	September 30, 2009	
	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]	$ 36	$ 15

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

(2) During the three and nine months ended September 30, 2009 and 2008, $0 was recognized in our results of operations as a result of the discontinuance of cash flow hedges because it was probable that the forecasted transaction would not occur.

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

a gross basis.
As of September 30, 2009, our commodity derivative assets and liabilities include amounts for non-trading and trading activities as follows:

	Derivative Assets		**Derivative Liabilities**		**Net Derivative Assets (Liabilities)**
	Current	**Long-Term**	**Current**	**Long-Term**	
			(in millions)		
Non-trading	$ 74	$ 57	$ 164	$ 83	$ (116)
Trading	76	6	52	4	26
Total derivatives	$ 150	$ 63	$ 216	$ 87	$ (90)

We have the following derivative commodity contracts outstanding as of September 30, 2009:

		Notional Volumes(2)	
Commodity	**Unit(1)**	**Current**	**Long-term**
		(in millions)	
Power	MWh	(4)	(5)
Capacity energy	MWh	(1)	(1)
Natural gas	MMBTU	(2)	25
Natural gas basis	MMBTU	(4)	
Coal	MMBTU	128	210

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

(2) Negative amounts indicate net forward sales.

Table of Contents

The income (loss) associated with our energy derivatives is:

Derivatives Not Designated as Hedging Instruments[1]	Three Months Ended September 30, 2009 Revenues	Three Months Ended September 30, 2009 Cost of Sales	Nine Months Ended September 30, 2009 Revenues	Nine Months Ended September 30, 2009 Cost of Sales
	(in millions)			
Non-Trading Commodity Contracts:				
Unrealized[2]	$ (25)	$ 34	$ (51)	$ 25
Realized[3][4][5]	105	(62)	292	(136)
Total non-trading	$ 80	$ (28)	$ 241	$ (111)
Trading Commodity Contracts:				
Unrealized	$	$ (2)	$	$ (4)
Realized[3]				20
Total trading	$	$ (2)	$	$ 16

(1) Interest rate swap instruments were liquidated in 2002 and the related deferred losses in accumulated other comprehensive loss are being amortized into interest expense through 2012. An immaterial amount was amortized during the three and nine months ended September 30, 2009 and 2008, which was included in interest expense under other operations.

(2) During 2007, we de-designated our remaining cash flow hedges. During the three and nine months ended September 30, 2009 and 2008, previously measured ineffectiveness gains (losses) in revenues reversing due to settlement of the derivative contracts were insignificant.

(3) 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.

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

(5) 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 6.

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

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(in millions)			
Revenues	$	$ 1	$	$ 1
Cost of sales	5	30	21	13
Total[(1)]	$ 5	$ 31	$ 21	$ 14

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

(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 our derivative assets and accounts receivable from our counterparties, after taking into consideration netting within each contract and any master netting contracts with counterparties. We believe this represents the maximum potential loss we would incur if our counterparties failed to perform according to their contract terms.

As of September 30, 2009, our derivative assets and accounts receivable, after taking into consideration netting within each contract and any master netting contracts with counterparties, are:

Credit Rating Equivalent	Exposure Before Collateral[(1)(2)]	Credit Collateral Held[(3)]	Exposure Net of Collateral	Number of Counterparties >10%	Net Exposure of Counterparties >10%
			(dollars in millions)		
Investment grade	$ 170	$ 13	$ 157	2(4)	$ 135
Non-investment grade					
No external ratings:					
Internally rated Investment grade	55		55	1(5)	45
Internally rated Non-investment grade	2	2			
Total	$ 227	$ 15	$ 212	3	$ 180

(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 2010.

(2) The table excludes amounts related to contracts classified as normal purchase/normal sale and non-derivative contractual commitments that are not

recorded in our consolidated balance sheets, except for any related accounts receivable. Such contractual commitments contain credit and economic risk if a counterparty does not perform. Nonperformance could have a material adverse impact on our future results of operations, financial condition and cash flows.

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

(4) These counterparties are a power grid operator and a financial institution.

(5) This counterparty is a financial institution.

As of December 31, 2008, three investment grade counterparties (a financial institution and two power grid operators) represented 63% ($156 million) of our credit exposure.

Based on our current credit ratings, any additional collateral postings that would be required from us due to a credit downgrade would be immaterial. As of September 30, 2009 and December 31, 2008, we have posted cash margin deposits of $169 million and $70 million, respectively, as collateral for our derivative liabilities receiving mark-to-market accounting treatment and our accounts payable (classified either as continuing or discontinued operations). Additionally, as of September 30, 2009 and December 31, 2008, we have $26 million and $103 million, respectively, in letters of credit issued as collateral for our derivative liabilities receiving mark-to-market accounting treatment and our accounts payable (classified either as continuing or discontinued operations). See note 7.

(6) Comprehensive Income (Loss)

The components of total comprehensive income (loss) are:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Net income (loss)	$ (15)	$ (1,038)	$ 637	$ (302)
Other comprehensive income, net of tax:				
Reclassification of net deferred loss from cash flow hedges realized into net income/loss (net of tax)	5	9	13	25
Unrealized gain on available-for-sale securities (net of tax)[1]		9	3	9
Reclassification of benefits actuarial net loss into net income/loss (net of tax)			1	
Reclassification of benefits, net prior service costs into net income/loss (net of tax)		1		1
Comprehensive income (loss)	$ (10)	$ (1,019)	$ 654	$ (267)

(1) As of September 30, 2009 and December 31, 2008, $12 million and $8 million, respectively, of unrealized net gains (excluding taxes) are included in accumulated other comprehensive loss for available-for-sale securities.

Table of Contents

(7) Debt

	September 30, 2009			December 31, 2008		
	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%	$	$	3.18%	$	$
Senior secured notes due 2014(2)(3)(4)	6.75	279	158	6.75	498(5)	
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	12.00	400	
PEDFA(6) fixed-rate bonds due 2036(7)	6.75	406	2	6.75	408(8)	
Total facilities, bonds and notes		1,985	560		2,606	
Other:						
Adjustment to fair value of debt(9)			8		4	13
Total other debt			8		4	13
Total debt		$ 1,985	$ 568		$ 2,610(10)	$ 13

(1) The weighted average stated interest rates are as of September 30, 2009 or December 31, 2008.

(2) We repurchased $61 million during the second and third quarters of 2009 and recognized gains on extinguishments of $1 million during the nine months ended September 30, 2009 related to the difference between the amounts paid and the net carrying value of the debt.

(3) During October 2009, we completed a tender offer and purchased for cash $127 million principal amount and recognized a loss on extinguishment of $5 million relating to the premium paid and the write off of deferred financing costs.

(4) During November 2009, we repurchased for cash $31 million principal amount.

(5) Excludes $169 million classified as discontinued operations as of

December 31, 2008. See note 17.

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

(7) During October 2009, we completed a tender offer and purchased for cash $2 million principal amount.

(8) Excludes $92 million classified as discontinued operations as of December 31, 2008. See note 17.

(9) Debt acquired in the Orion Power acquisition was adjusted to fair value as of the acquisition date. Included in interest expense is amortization of $3 million and $2 million for valuation adjustments for debt during the three months ended September 30, 2009 and 2008, respectively, and

$9 million and $8 million during the nine months ended September 30, 2009 and 2008, respectively.

(10) Excludes $261 million classified as discontinued operations as of December 31, 2008. See note 17.

Amounts borrowed and available for borrowing under our revolving credit agreements as of September 30, 2009 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		144	106
Total	$ 750	$	$ 144	$ 606

12

Table of Contents

(8) Earnings (Loss) Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Income (loss) from continuing operations (basic and diluted)	$ (19)	$ 93	$ (228)	$ 188

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(shares in thousands)			
Diluted Weighted Average Shares Calculation:				
Weighted average shares outstanding (basic)	351,561	349,200	350,908	347,086
Plus: Incremental shares from assumed conversions:				
Stock options	(1)	3,390	(1)	3,986
Restricted stock	(1)	428	(1)	516
Employee stock purchase plan	(1)		(1)	16
5.00% convertible senior subordinated notes	N/A(2)	2	N/A(2)	77
Warrants	N/A(3)	674	N/A(3)	2,277
Weighted average shares outstanding assuming conversion (diluted)	351,561	353,694	350,908	353,958

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

(2) In December 2006, we converted 99.2% of our convertible

senior subordinated notes to common stock. During 2008, the remaining outstanding notes were converted to common stock.

(3) All unexercised warrants expired in August 2008.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(shares in thousands, dollars in millions)			
Shares excluded from the calculation of diluted earnings (loss) per share	619(1)	N/A(2)	501(1)	N/A(2)
Shares excluded from the calculation of diluted earnings (loss) per share because the exercise price exceeded the average market price	4,970(3)	2,314(3)	4,970(3)	2,300(3)

(1) Potential shares excluded consist of stock options, restricted stock and shares related to the employee stock purchase plan.

(2) Not applicable as we included the item in the calculation of diluted earnings/loss per share.

(3) Includes stock options.

Table of Contents

(9) Income Taxes

(a) Tax Rate Reconciliation.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Federal statutory rate	(35)%	35%	(35)%	35%
Additions (reductions) resulting from:				
Federal valuation allowance[1]	134		4	
State income taxes, net of federal income taxes	(20) [2]	14[3]	(2) [4]	10[5]
Other	30[6][7]		1[6][7]	1
Effective rate	109%	49%	(32)%	46%

(1) Our changes to the federal valuation allowance are recorded at RRI Energy, Inc.

(2) Of this percentage, $2 million relates to valuation allowance release.

(3) Of this percentage, $2 million relates to additional valuation allowance.

(4) Of this percentage, $13 million relates to additional valuation

allowance.

(5) Of this percentage, $6 million relates to additional valuation allowance.

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

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

(b) Valuation Allowances.

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

Our valuation allowances for continuing deferred tax assets are:

	Federal	State	Capital, Foreign and Other, Net
		(in millions)	
As of December 31, 2008	$ 39(1)	$ 103	$ 14
Changes in valuation allowance	16	6	
As of March 31, 2009	55	109	14
Changes in valuation allowance	(16)	9	1
As of June 30, 2009	39	118	15
Changes in valuation allowance	12	(2)	(15)
As of September 30, 2009	$ 51	$ 116	$

(1) Amount has been reduced by $10 million reclassification of deferred tax asset/liability components.

(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 did not change significantly during the three and nine months ended September 30, 2009 and 2008.

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:

- $177 million payment to CenterPoint during 2004 related to our residential customers;
- $351 million charge during 2005 to settle certain civil litigation and claims relating to the Western states energy crisis; and
- 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.). The IRS has informed us it expects to issue a notice of denial of our administrative claim for refund involving these California-related items and we expect to institute refund litigation with respect to this claim in the U.S. District Court or U.S. Court of Federal Claims. In order to set a jurisdictional prerequisite to institute such a refund suit, we expect to make a payment of approximately $60 million to $65 million (which includes an asserted tax liability of $38 million plus interest) some time during late 2009 or early 2010. If the IRS were to ultimately prevail in this matter, there would be no impact on the effective tax rate except for interest. The payment will be refunded with interest if we are successful in the litigation.

(10) 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 $52 million as of September 2009 and no liability is recorded in our consolidated balance sheet for this item.

We also guarantee the $500 million PEDFA bonds, which are included in our consolidated balance sheet as either outstanding debt or liabilities of discontinued operations ($408 million and $500 million are in our consolidated balance sheet as of September 30, 2009 and December 31, 2008, respectively). Our guarantees are secured by the same collateral as our 6.75% senior secured notes. The guarantees require us to comply with covenants similar to those in the 6.75% senior secured notes indenture. The PEDFA bonds will become secured by certain assets of our Seward power plant if the collateral supporting both the 6.75% senior secured 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 June and July 2009, we purchased $92 million of the PEDFA bonds and are the holder of these repurchased bonds. During October 2009, we completed a tender offer and purchased for cash $2 million of the 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.

We have guaranteed payments to a third party relating to energy sales from El Dorado Energy, LLC, a former investment. The estimated maximum potential amount of future payments under this guarantee is approximately $21 million as of September 30, 2009 and no liability is recorded in our consolidated balance sheet for this item.

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.

Table of Contents

(11) Contingencies

We are party to many legal and governmental 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.

The following proceedings relate to alleged conduct in the natural gas markets. We have settled a number of proceedings that were pending in California and other Western states; however, some other proceedings remain pending.

We are party to eight lawsuits, several of which are class action lawsuits, in state and federal courts in Kansas, Missouri, Nevada, Tennessee 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.

Recent developments in the natural gas proceedings include:

In January 2009, we reached an agreement to settle the five California-related cases pending in federal court in Nevada for $3 million. The court approved the settlement and a final judgment dismissing the cases was entered in September 2009. The charges incurred in connection with the settlement were expensed in the third quarter of 2008 and paid in the third quarter of 2009. This settlement resolved all of the remaining California gas cases.

In January 2009, the Circuit Court of Jackson County, Missouri dismissed the case filed by the Missouri Public Service Commission for lack of standing to bring the action. An appeal was filed in February 2009 and remains pending.

(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 generation facilities 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.

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 ($11 million and $12 million as of September 30, 2009 and December 31, 2008, respectively) associated with these environmental liabilities as part of our asset retirement obligations. See note 2(q) to our consolidated financial statements in our Form 10-K.

Remediation Obligations. We are responsible for environmental costs related to site contamination investigations and remediation requirements at four power plants in New Jersey. We recorded the estimated long-term liability for the remediation costs of $7 million and $8 million as of September 30, 2009 and December 31, 2008, respectively.

Conemaugh Action. 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. However, if PennEnvironment and the Sierra Club are successful, we could incur additional capital expenditures associated with the implementation of discharge reductions and penalties, which we do not believe would be material.

Mandalay Notice of Violation. In October 2009, we made a settlement payment of $111,000 to the California State Water Resources Control Board Los Angeles Region to resolve alleged violations of our wastewater discharge permit for our Mandalay plant.

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. We believe this claim lacks legal merit. In October 2009, the District Court ordered that the case be dismissed. The plaintiffs may appeal this order or seek rehearing of the case in light of recent Court of Appeals rulings in global warming actions in other circuits.

(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 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 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 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 Texas retail business if it is ultimately not allowed to include in its stranded cost calculation EMCs credited to our 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 Texas retail business. Regardless of the outcome of the Texas Supreme Court proceeding, we believe that any claim by CenterPoint that we are liable to it for any EMCs credited to our Texas retail business lacks legal merit and is unsupported by our Master Separation Agreement with CenterPoint. In addition, CenterPoint has publicly stated that it has no legal recourse against us or our Texas retail business for any reduction in the amount of its recoverable stranded costs should EMCs credited to our Texas retail business be excluded.

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 $58 million (including interest and penalties of $20 million) relating primarily to the sourcing of receipts for 2000 through 2006. We are contesting the audit assessments related to this issue.

Sales Tax Contingencies. Some of our sales tax computations are subject to challenge under audit. As of September 30, 2009 and December 31, 2008, we have $12 million and $13 million, respectively, accrued in current and long-term liabilities for both continuing and discontinued operations relating to these contingencies.

Table of Contents

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 to which we were a party. The agreement set Kern s transportation rates as of November 2004 at 12.5% return on equity, which resulted in a refund to us of $30 million during the fourth quarter of 2008 (recorded as a current liability). In January 2009, FERC rejected the settlement and directed Kern to recalculate the refunds based on a rate of 11.55% return on equity. During 2009, we accrued an additional $2 million current liability related to the revised rate of return on equity. We expect to receive an additional $5 million in 2010. If the order rejecting the settlement is appealed, that amount may be subject to adjustment on resolution of the appeal.

(12) 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 10(b) to our consolidated financial statements in our 2008 Form 10-K for additional information about pension and postretirement benefits.

Net periodic benefit costs are:

	Pension Three months ended September 30,		Postretirement Three months ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Service cost	$ 1	$ 1	$	$
Interest cost	1	1	1	1
Expected return on plan assets	(1)	(1)		
Net amortization	1	1		
Net curtailments (gain) loss	1		(1)	
Adjustment to annual expense				2
Special termination benefits	1		1	
Net periodic benefit costs	$ 4	$ 2	$ 1	$ 3

	Pension Nine months ended September 30,		Postretirement Nine months ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Service cost	$ 4	$ 4	$ 1	$ 1
Interest cost	4	4	3	3
Expected return on plan assets	(3)	(4)		
Net amortization	3	1	1	
Net curtailments (gain) loss	1		(1)	
Adjustment to annual expense				2
Special termination benefits	1		1	
Net periodic benefit costs	$ 10	$ 5	$ 5	$ 6

Contributions. During the three months ended September 30, 2009 and 2008, we made $18 million and $4 million, respectively, in contributions to our pension plans and other postretirement benefit plans. During the nine months ended September 30, 2009 and 2008, we made $20 million and $5 million, respectively, in contributions to our pension plans and other postretirement benefit plans.

(13) Collective Bargaining Arrangements

As of September 30, 2009, approximately 45% of our employees are subject to collective bargaining arrangements. Approximately 30% of our employees are subject to collective bargaining arrangements that will expire by September 30, 2010. We intend to negotiate the renewal of these agreements.

(14) 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.

Table of Contents

Condensed Consolidating Statements of Operations.

	Three Months Ended September 30, 2009				
	RRI Energy	Guarantors	Non-Guarantors	Adjustments (1)	Consolidated
			(in millions)		
Revenues	$	$ 511	$ 202	$ (206)	$ 507
Cost of sales		365	107	(205)	267
Operation and maintenance		36	80	(1)	115
General and administrative		3	20		23
Gains on sales of assets and emission and exchange allowances, net			(1)		(1)
Depreciation and amortization		31	37		68
Total		435	243	(206)	472
Operating income (loss)		76	(41)		35
Income of equity investment, net		1			1
Income (loss) of equity investments of consolidated subsidiaries	14	(15)		1	
Interest expense	(37)	(7)	(1)		(45)
Interest income (expense) affiliated companies, net	19	(3)	(16)		
Total other expense	(4)	(24)	(17)	1	(44)
Income (loss) from continuing operations before income taxes	(4)	52	(58)	1	(9)
Income tax expense (benefit)	5	26	(17)	(4)	10
Income (loss) from continuing operations	(9)	26	(41)	5	(19)
Income (loss) from discontinued operations	(6)	4	6		4
Net income (loss)	$ (15)	$ 30	$ (35)	$ 5	$ (15)

	Three Months Ended September 30, 2008				
	RRI Energy	Guarantors	Non-Guarantors	Adjustments (1)	Consolidated
			(in millions)		

Revenues	$	$ 924	$ 421	$ (385)	$ 960
Cost of sales		747	150	(383)	514
Operation and maintenance		40	96	(1)	135
General and administrative		4	21	(1)	24
Western states litigation and similar settlements		3			3
Gains on sales of assets and emission and exchange allowances, net		(17)			(17)
Depreciation and amortization		31	47		78
Total		808	314	(385)	737
Operating income		116	107		223
Income of equity investment, net		2			2
Income (loss) of equity investments of consolidated subsidiaries	(1,042)	40		1,002	
Debt extinguishment losses	(1)				(1)
Other, net			4		4
Interest expense	(38)	(7)	(5)		(50)
Interest income	4	1			5
Interest income (expense) affiliated companies, net	41	(26)	(15)		
Total other income (expense)	(1,036)	10	(16)	1,002	(40)
Income (loss) from continuing operations before income taxes	(1,036)	126	91	1,002	183
Income tax expense	2	29	37	22	90
Income (loss) from continuing operations	(1,038)	97	54	980	93
Income (loss) from discontinued operations		19	(1,161)	11	(1,131)
Net income (loss)	$ (1,038)	$ 116	$ (1,107)	$ 991	$ (1,038)

	Nine Months Ended September 30, 2009				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments (1)	Consolidated
Revenues	$	$ 1,347	$ 645	$ (629)	$ 1,363
Cost of sales		1,025	472	(625)	872
Operation and maintenance		145	288	(4)	429
General and administrative		7	73		80
Gains on sales of assets and emission and exchange allowances, net		(17)	(4)		(21)
Depreciation and amortization		95	108		203
Total		1,255	937	(629)	1,563
Operating income (loss)		92	(292)		(200)
Income of equity investment, net		1			1
Loss of equity investments of consolidated subsidiaries	(163)	(74)		237	
Debt extinguishments gain	1				1
Interest expense	(111)	(21)	(5)		(137)
Interest income	1				1
Interest income (expense) affiliated companies, net	54	(9)	(45)		
Total other expense	(218)	(103)	(50)	237	(134)
Loss from continuing operations before income taxes	(218)	(11)	(342)	237	(334)
Income tax expense (benefit)	(6)	24	(123)	(1)	(106)
Loss from continuing operations	(212)	(35)	(219)	238	(228)
Income from discontinued operations	849	11	5		865
Net income (loss)	$ 637	$ (24)	$ (214)	$ 238	$ 637

	Nine Months Ended September 30, 2008				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments (1)	Consolidated

Revenues	$	$ 2,776	$ 1,252	$ (1,174)	$ 2,854
Cost of sales		2,342	417	(1,167)	1,592
Operation and maintenance		152	308	(4)	456
General and administrative	1	17	71	(3)	86
Western states litigation and similar settlements	34	3			37
Gains on sales of assets and emission and exchange allowances, net		(38)	(2)		(40)
Depreciation and amortization		100	144		244
Total	35	2,576	938	(1,174)	2,375
Operating income (loss)	(35)	200	314		479
Income of equity investment, net		3			3
Income (loss) of equity investments of consolidated subsidiaries	(303)	119		184	
Debt extinguishment losses	(2)				(2)
Other, net			4		4
Interest expense	(115)	(20)	(17)		(152)
Interest income	14	4	1		19
Interest income (expense) affiliated companies, net	140	(92)	(48)		
Total other income (expense)	(266)	14	(60)	184	(128)
Income (loss) from continuing operations before income taxes	(301)	214	254	184	351
Income tax expense	1	36	104	22	163
Income (loss) from continuing operations	(302)	178	150	162	188
Income (loss) from discontinued operations		2	(500)	8	(490)
Net income (loss)	$ (302)	$ 180	$ (350)	$ 170	$ (302)

(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.

Table of Contents

Condensed Consolidating Balance Sheets.

	September 30, 2009				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments (1)	Consolidated
ASSETS					
Current Assets:					
Cash and cash equivalents	$ 1,233	$ 2	$ 19	$	$ 1,254
Restricted cash		2	1		3
Accounts and notes receivable, principally customer	11	126	16	(8)	145
Accounts and notes receivable affiliated companies	1,641	464	153	(2,258)	
Inventory		144	174		318
Derivative assets		117	33		150
Investment in and receivables from Channelview, net	1	23			24
Other current assets	48	152	93	(13)	280
Current assets of discontinued operations	125	168	4	(135)	162
Total current assets	3,059	1,198	493	(2,414)	2,336
Property, Plant and Equipment, net		2,280	2,491		4,771
Other Assets:					
Other intangibles, net		114	256		370
Notes receivable affiliated companies	1,907	553		(2,460)	
Equity investments of consolidated subsidiaries	1,798	259		(2,057)	
Derivative assets		50	13		63
Other long-term assets	42	793	361	(666)	530
Long-term assets of discontinued operations	1	11	2	(4)	10
Total other assets	3,748	1,780	632	(5,187)	973
Total Assets	$ 6,807	$ 5,258	$ 3,616	$ (7,601)	$ 8,080
LIABILITIES AND EQUITY					
Current Liabilities:					
Current portion of long-term debt and short-term borrowings	$ 158	$ 2	$ 408	$	$ 568
Accounts payable, principally trade		28	107		135

Accounts and notes payable affiliated companies		1,576	682	(2,258)	
Derivative liabilities		86	130		216
Other current liabilities	40	239	37	(72)	244
Current liabilities of discontinued operations	25	174	8	(135)	72
Total current liabilities	223	2,105	1,372	(2,465)	1,235
Other Liabilities:					
Notes payable affiliated companies		1,887	573	(2,460)	
Derivative liabilities		12	75		87
Other long-term liabilities	543	144	226	(616)	297
Long-term liabilities of discontinued operations	5	15	3	(4)	19
Total other liabilities	548	2,058	877	(3,080)	403
Long-term Debt	1,579	406			1,985
Commitments and Contingencies					
Temporary Equity Stock-based Compensation	6				6
Total Stockholders Equity	4,451	689	1,367	(2,056)	4,451
Total Liabilities and Equity	$ 6,807	$ 5,258	$ 3,616	$ (7,601)	$ 8,080

Table of Contents

	RRI Energy	Guarantors	Non-Guarantors	Adjustments (1)	Consolidated
	December 31, 2008				
			(in millions)		
ASSETS					
Current Assets:					
Cash and cash equivalents	$ 970	$	$ 34	$	$ 1,004
Restricted cash		1	2		3
Accounts and notes receivable, principally customer	15	216	33	(14)	250
Accounts and notes receivable affiliated companies	1,100	268	183	(1,551)	
Inventory		153	162		315
Derivative assets		127	34		161
Investment in and receivables from Channelview, net	1	58			59
Other current assets	5	56	126	(30)	157
Current assets of discontinued operations	272	211	2,661	(638)	2,506
Total current assets	2,363	1,090	3,235	(2,233)	4,455
Property, Plant and Equipment, net		2,369	2,451		4,820
Other Assets:					
Other intangibles, net		150	264	(34)	380
Notes receivable affiliated companies	2,260	578	54	(2,892)	
Equity investments of consolidated subsidiaries	1,731	332		(2,063)	
Derivative assets		37	42		79
Other long-term assets	45	749	344	(645)	493
Long-term assets of discontinued operations	2	12	686	(205)	495
Total other assets	4,038	1,858	1,390	(5,839)	1,447
Total Assets	$ 6,401	$ 5,317	$ 7,076	$ (8,072)	$ 10,722
LIABILITIES AND EQUITY					
Current Liabilities:					
Current portion of long-term debt and short-term borrowings	$	$	$ 13	$	$ 13
Accounts payable, principally trade		31	132	(6)	157
Accounts and notes payable affiliated companies		1,307	244	(1,551)	
Derivative liabilities		29	173		202
Other current liabilities	10	306	47	(72)	291

Current liabilities of discontinued operations	61	147	2,805	(637)	2,376
Total current liabilities	71	1,820	3,414	(2,266)	3,039
Other Liabilities:					
Notes payable affiliated companies		2,132	760	(2,892)	
Derivative liabilities		4	137		141
Other long-term liabilities	547	119	251	(645)	272
Long-term liabilities of discontinued operations	198	103	778	(206)	873
Total other liabilities	745	2,358	1,926	(3,743)	1,286
Long-term Debt	1,798	408	404		2,610
Commitments and Contingencies					
Temporary Equity Stock-based Compensation	9				9
Total Stockholders Equity	3,778	731	1,332	(2,063)	3,778
Total Liabilities and Equity	$ 6,401	$ 5,317	$ 7,076	$ (8,072)	$ 10,722

(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.

Table of Contents

Condensed Consolidating Statements of Cash Flows.

	Nine Months Ended September 30, 2009				
	RRI Energy	Guarantors	Non-Guarantors (in millions)	Adjustments[1]	Consolidated
Cash Flows from Operating Activities:					
Net cash provided by (used in) continuing operations from operating activities	$ (115)	$ 43	$ (203)	$	$ (275)
Net cash provided by discontinued operations from operating activities	134	49	351		534
Net cash provided by operating activities	19	92	148		259
Cash Flows from Investing Activities:					
Capital expenditures		(17)	(141)		(158)
Investments in, advances to and from and distributions from subsidiaries, net[2]	(244)			244	
Proceeds from sales of assets, net		36			36
Proceeds from sales (purchases) of emission allowances, net		43	(32)		11
Other, net		4			4
Net cash provided by (used in) continuing operations from investing activities	(244)	66	(173)	244	(107)
Net cash provided by (used in) discontinued operations from investing activities	711	6	(418)	15	314
Net cash provided by (used in) investing activities	467	72	(591)	259	207
Cash Flows from Financing Activities:					
Payments of long-term debt	(59)				(59)
Changes in notes with affiliated companies, net[3]		(85)	329	(244)	
Proceeds from issuances of stock	4				4

Net cash provided by (used in) continuing operations from financing activities	(55)	(85)	329	(244)	(55)
Net cash used in discontinued operations from financing activities	(168)	(75)	(3)	(15)	(261)
Net cash provided by (used in) financing activities	(223)	(160)	326	(259)	(316)
Net Change in Cash and Cash Equivalents, Total Operations	263	4	(117)		150
Less: Net Change in Cash and Cash Equivalents, Discontinued Operations		2	(102)		(100)
Cash and Cash Equivalents at Beginning of Period, Continuing Operations	970		34		1,004
Cash and Cash Equivalents at End of Period, Continuing Operations	$ 1,233	$ 2	$ 19	$	$ 1,254

Table of Contents

	Nine Months Ended September 30, 2008				
	RRI Energy	Guarantors	Non-Guarantors	Adjustments[1]	Consolidated
	(in millions)				
Cash Flows from Operating Activities:					
Net cash provided by (used in) continuing operations from operating activities	$ 81	$ (21)	$ 445	$	$ 505
Net cash provided by (used in) discontinued operations from operating activities	(4)	49	(282)		(237)
Net cash provided by operating activities	77	28	163		268
Cash Flows from Investing Activities:					
Capital expenditures		(19)	(172)		(191)
Investments in, advances to and from and distributions from subsidiaries, net[2]	345	57	(58)	(344)	
Proceeds from sales of assets		18			18
Proceeds from sales (purchases) of emission allowances, net		74	(61)		13
Restricted cash		(2)	(1)		(3)
Other, net		4			4
Net cash provided by (used in) continuing operations from investing activities	345	132	(292)	(344)	(159)
Net cash provided by (used in) discontinued operations from investing activities	(233)		204	4	(25)
Net cash provided by (used in) investing activities	112	132	(88)	(340)	(184)
Cash Flows from Financing Activities:					
Payments of long-term debt	(58)				(58)
Changes in notes with affiliated companies, net[3]		(178)	(166)	344	
Payments of debt extinguishments	(1)				(1)
Proceeds from issuances of stock	14				14
Net cash used in continuing operations from financing activities	(45)	(178)	(166)	344	(45)

Net cash provided by (used in) discontinued operations from financing activities		17	(13)	(4)	
Net cash used in financing activities	(45)	(161)	(179)	340	(45)
Net Change in Cash and Cash Equivalents, Total Operations	144	(1)	(104)		39
Less: Net Change in Cash and Cash Equivalents, Discontinued Operations			(91)		(91)
Cash and Cash Equivalents at Beginning of Period, Continuing Operations	490	1	33		524
Cash and Cash Equivalents at End of Period, Continuing Operations	$ 634	$	$ 20	$	$ 654

(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.

(15) Reportable Segments

Segments. Following the sale of our Texas retail business and commencing in the third quarter of 2009, 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. We have recast our 2008 data and presented our new segment information in this note on a consistent basis for the three and nine months ended September 30, 2009 and 2008. 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 and capacity revenues and (b) 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 energy gross margin is calculated using the power sales prices received by the plants less market-based delivered fuel costs. Open energy gross margin excludes the effects of other margin, hedges and other items and unrealized gains/losses on energy derivatives. 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 enter into hedges primarily to mitigate (a) certain operational and market risks at our generation assets and (b) some of the downside risk to our earnings and cash flows. 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 power sales prices received by the plants less market-based delivered fuel costs and the actual amounts paid or received during the period. See notes 3 and 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 notes 3 and 4.

25

Table of Contents

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 September 30, 2009:							
Revenues from external customers	$ 211	$ 129	$ 134	$ 28		$ 5(1)	$ 507(2)
Open energy gross margin	$ 43	$ 12	$ 3	$			$ 58
Other margin	57	55	78	19			209
Open gross margin(3)	$ 100	$ 67	$ 81	$ 19			$ 267(4)
Gains on sales of assets and emission and exchange allowances, net	$	$	$	$		$ 1	$ 1
Three months ended September 30, 2008:							
Revenues from external customers	$ 466	$ 174	$ 296	$ 37		$ (13)(1)	$ 960(5)
Open energy gross margin	$ 175	$ 20	$ 7	$ 1			$ 203
Other margin	53	46	83	16			198
Open gross margin(3)	$ 228	$ 66	$ 90	$ 17			$ 401(6)
Gains on sales of assets and emission and exchange allowances, net	$	$	$	$ 6(7)		$ 11(8)	$ 17
Nine months ended September 30, 2009 (unless otherwise indicated):							
Revenues from external customers	$ 662	$ 382	$ 248	$ 75		$ (4)(1)	$ 1,363(9)
Open energy gross margin	$ 178	$ 18	$ 12	$			$ 208
Other margin	134	137	102	48			421
Open gross margin(3)	$ 312	$ 155	$ 114	$ 48			$ 629(10)
Gains on sales of assets and emission and exchange allowances, net	$	$	$ 3	$		$ 18(11)	$ 21

Total assets as of September 30, 2009	$ 3,568[12]	$ 1,327[12]	$ 178[12]	$ 723[12]	$ 172	$ 2,112[13]	$ 8,080
Nine months ended September 30, 2008 (unless otherwise indicated):							
Revenues from external customers	$ 1,346	$ 515	$ 626	$ 400[14]		$ (33)[1]	$ 2,854[15]
Open energy gross margin	$ 612	$ 40	$ (1)	$ 1			$ 652
Other margin	102	106	139	41			388
Open gross margin[3]	$ 714	$ 146	$ 138	$ 42			$ 1,040[16]
Gains on sales of assets and emission and exchange allowances, net	$	$	$	$ 1[7]		$ 39[8]	$ 40
Total assets as of December 31, 2008	$ 3,497[12]	$ 1,366[12]	$ 186[12]	$ 752[12]	$ 3,001	$ 1,920[13]	$ 10,722

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

(2) Includes $242 million in revenues from a single counterparty, which represented 48% of our consolidated revenues. This counterparty is included in our East Coal and East Gas segments. As of

September 30, 2009, $30 million was outstanding from this counterparty.

(3) Represents our segment profitability measure.

(4) Excludes $(34) million and $7 million of hedges and other items and unrealized gains on energy derivatives, respectively, that are included in our consolidated revenues or cost of sales.

(5) Includes $478 million in revenues from a single counterparty, which represented 50% of our consolidated revenues. This counterparty is included in our East Coal and East Gas segments.

(6) Excludes $85 million and $(40) million of hedges and other items and unrealized losses on energy derivatives, respectively, that are included in our consolidated revenues or cost of sales.

(7) Relates to gains on the investment in and receivables from Channelview, which was deconsolidated in August 2007 and the plant was sold in July 2008.

(8) Primarily relates to gains on sales of CO_2 exchange allowances.

(9) Includes $668 million in revenues from a single counterparty, which represented 49% of our consolidated revenues. This counterparty is included in our East Coal and East Gas

segments.

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

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

(12) Primarily relates to property, plant and equipment, inventory and emission allowances. East Coal also includes the prepaid REMA leases of $351 million and $332 million for September 30, 2009 and December 31, 2008, respectively.

(13) Represents assets not applicable to a segment. Includes primarily cash

and cash equivalents, accounts and notes receivable, derivative assets, margin deposits, certain property, plant and equipment related to corporate assets and other assets.

(14) Includes $253 million from affiliates.

(15) Includes $1.3 billion in revenues from a single counterparty, which represented 46% of our consolidated revenues. This counterparty is included in our East Coal and East Gas segments.

(16) Excludes $164 million and $58 million of hedges and other items and unrealized gains on energy derivatives, respectively, that are included in our consolidated revenues or cost of sales.

	Three Months Ended September 30,	Nine Months Ended September 30,

	2009	2008	2009	2008
		(in millions)		
Open gross margin for all segments	$ 267	$ 401	$ 629	$ 1,040
Hedges and other items	(34)	85	(108)	164
Unrealized gains (losses) on energy derivatives	7	(40)	(30)	58
Operation and maintenance	(115)	(135)	(429)	(456)
General and administrative	(23)	(24)	(80)	(86)
Western states litigation and similar settlements		(3)		(37)
Gains on sales of assets and emission and exchange allowances, net	1	17	21	40
Depreciation	(59)	(57)	(178)	(182)
Amortization	(9)	(21)	(25)	(62)
Operating income (loss)	35	223	(200)	479
Income of equity investment, net	1	2	1	3
Debt extinguishments gains (losses)		(1)	1	(2)
Other, net		4		4
Interest expense	(45)	(50)	(137)	(152)
Interest income		5	1	19
Income (loss) from continuing operations before income taxes	$ (9)	$ 183	$ (334)	$ 351

(16) Sale of Channelview s Plant and the Bankruptcy Filings

On August 20, 2007, Channelview filed voluntary petitions in the United States Bankruptcy Court for the District of Delaware for reorganization under Chapter 11 of the Bankruptcy Code. Channelview filed for bankruptcy protection to prevent the lenders from exercising their remedies, including foreclosing on the project. The bankruptcy cases have been jointly administered, with Channelview managing its business in the ordinary course as debtors-in-possession subject to the supervision of the bankruptcy court.

In July 2008, Channelview sold its plant and related contracts for $500 million and paid off its secured lenders. During 2008, we recognized a $6 million gain relating to our net investment in and receivables from Channelview and incurrence of sale-related costs (classified in gains (losses) on sales of assets and emission and exchange allowances, net). As of September 30, 2009 and December 31, 2008, our net investment in and receivables from Channelview was $24 million and $59 million, respectively, classified as a current asset.

Channelview has distributed funds to us relating primarily to net proceeds from the sale, pre-petition sales of fuel to Channelview, funds from operations and funds escrowed for potential indemnification claims. We received $25 million during 2008 and $35 million during the second quarter of 2009.

As a result of the bankruptcies, we deconsolidated Channelview s financial results beginning August 20, 2007, and began reporting our investment in Channelview using the cost method. We continued to account for Channelview as a cost method investment until it emerged from bankruptcy, which occurred in October 2009. The following table describes the assets we expect to consolidate upon the emergence from bankruptcy of Channelview:

	September 30, 2009 (in millions)	
Cash	$	17(1)
Deferred tax assets relating to federal and state net operating loss carryforwards		18(2)

(1) Of this amount, $10 million is payable to a third party.

(2) We have assessed our future ability to use these deferred tax assets and have provided a valuation allowance for this amount in our consolidated balance sheet. See note 9.

(17) Discontinued Operations

(a) Retail Energy Segment.

General. On May 1, 2009, we sold our Texas retail business to a subsidiary (the buyer) of NRG Energy, Inc. (NRG) for $287.5 million in cash plus the value of the net working capital. We currently estimate the net working capital to be $78 million. We estimate our net proceeds will be $312 million after certain expenses. In connection with the sale, we received net proceeds of $297 million during primarily the second quarter of 2009 and $15 million during the third quarter of 2009. This sale also included the rights to the Reliant Energy name. Accordingly, we changed our name to RRI Energy, Inc. on May 2, 2009. In connection with the sale, the lawsuit against our former retail affiliates related to the termination of the retail working capital facility has been dismissed.

In connection with the sale transaction, we entered into a two-year sublease on our corporate office building with the buyer, with sublease rental income totaling $17 million over that period. We also entered a one-year transition services agreement with the buyer, which includes terms and conditions for information technology services, accounting services and human resources.

Pre-Tax Gain on Sale. We recognized during the second quarter of 2009 a pre-tax gain on this sale of $1.2 billion, which is primarily due to the net derivative liability balance of $1.1 billion included in the transaction.

Federal Valuation Allowance. As a result of the sale, we released $50 million of our discontinued federal valuation allowance for deferred tax assets in discontinued operations during the three months ended June 30, 2009.

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 $225 million of the outstanding debt ($147 million of the secured notes and $78 million of the PEDFA bonds) in June 2009 and an additional $36 million ($22 million of the secured notes and $14 million of PEDFA bonds) in July 2009. These amounts and activity have been classified in discontinued operations. See note 7. We also classified as discontinued operations the related deferred financing costs and interest expense on this debt. We allocated an insignificant amount and $4 million of related interest expense during the three months ended September 30, 2009 and 2008, respectively, to discontinued operations. We allocated $8 million and $12 million of related interest expense during the nine months ended September 30, 2009 and 2008, respectively, to discontinued operations.

Other Retail Energy Segment Discontinued Operations. We sold our C&I contracts in the PJM (excluding Illinois) and New York areas (collectively, Northeast) in December 2008. As this was a part of our retail energy segment, we have included this activity in our discontinued operations. We have also included our Illinois C&I activity in discontinued operations as it was a part of our retail energy segment and is held-for-sale.

(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) property tax and sales and use tax settlements. In addition, we periodically record amounts for contingent consideration received 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.

Table of Contents

(c) All Discontinued Operations.

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

	Retail Energy Segment	New York Plants	European Energy	Total
		(in millions)		
Three Months Ended September 30, 2009				
Revenues	$ 14(1)	$	$	$ 14
Income before income tax expense/benefit	5(2)			5
Three Months Ended September 30, 2008				
Revenues	$ 2,778(3)	$	$	$ 2,778
Loss before income tax expense/benefit	(1,784)(4)			(1,784)
Nine Months Ended September 30, 2009				
Revenues	$ 2,028(5)	$ 2	$	$ 2,030
Income before income tax expense/benefit	1,262(6)(7)	3	9	1,274
Nine Months Ended September 30, 2008				
Revenues	$ 7,124(8)	$	$	$ 7,124
Income (loss) before income tax expense/benefit	(770)(9)	(3)	7	(766)

(1) Includes $11 million related to our Illinois C&I activity.

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

(3) Includes $22 million related to our Illinois C&I activity.

(4) Includes $1.7 billion of unrealized losses on energy derivatives.

(5)

Includes $51 million related to our Illinois C&I activity.

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

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

(8) Includes $42 million related to our Illinois C&I activity.

(9) Includes $624 million of unrealized losses on energy derivatives.

Table of Contents

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

	September 30, 2009	December 31, 2008
	(in millions)	
Current Assets:		
Cash and cash equivalents	$ 5	$ 105
Accounts receivable, principally customer, net	10	870
Derivative assets	57	1,010
Margin deposits	88	295
Accumulated deferred income taxes, net of federal valuation allowance of $4 million and $38 million	2	217
Other current assets		9
Total current assets	162	2,506
Property, Plant and Equipment, net		57
Other Assets:		
Goodwill and other intangibles, net		59
Derivative assets	6	324
Accumulated deferred income taxes, net of federal valuation allowance of $3 million and $12 million	4	48
Other		7
Total long-term assets	10	495
Total Assets	$ 172	$ 3,001
Current Liabilities:		
Accounts payable, principally trade	$ 1	$ 480
Derivative liabilities	56	1,637
Margin deposits	9	
Accrual for transmission and distribution charges		83
Retail customer deposits		59
Other current liabilities	6	117
Total current liabilities	72	2,376
Other Liabilities:		
Derivative liabilities	12	612
Other liabilities	7	
Total other liabilities	19	612
Long-term Debt		261
Total long-term liabilities	19	873
Total Liabilities	$ 91	$ 3,249

30

Table of Contents

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.

Business Overview

We provide electricity and energy services to wholesale customers in competitive power generation energy markets in the United States through our ownership and operation of and contracting for power generation capacity. We have over 14,000 MW of power generation capacity.

We believe 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
- Intensely focus on operational excellence
- Employ a flexible operating model through the cycle
- Utilize a disciplined capital investment approach
- Create value from industry consolidation

The current market environment is challenging given the uncertainty in the financial markets, possible legislative and regulatory environmental matters, the overall economy and lower power demand. Additionally, current commodity prices and spreads are depressed relative to historical levels. While we believe these conditions will improve, the timing is uncertain.

We have taken a number of actions to navigate the current market challenges and position us for the longer term market recovery, with a focus on maximizing cash flow and building ample liquidity. Some of these actions include:

- Selling the Texas retail business
- Implementing a modest hedging program to achieve a high probability of achieving free cash flow breakeven or better even if market conditions deteriorate further
- Intensely focusing on operating efficiency and effectiveness
- Implementing flexible plant-specific operating models
- Realigning corporate support costs

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.

Key Earnings Drivers. Our earnings 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. Our margins are driven by a number of factors, including the prices of power, capacity, natural gas, coal and fuel oil, the cost of emissions and transmission, as well as weather and global macro-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 generating assets 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
- Generation asset 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
- Generation asset fuel type and efficiency

31

Table of Contents

Other margin

- Capacity prices and payments
- 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

Flexible Plant-Specific Operating Model. We have different operating approaches for our power generation facilities. These operating approaches are determined by each facility s condition, environmental controls, profitability, market rules, upside availability and value drivers. We have separated our facilities into four general groups for the purposes of developing an operating model.

- *Long-term value* This part of our fleet, representing approximately 2,500 MW, is well positioned to generate revenue for the foreseeable future, and we would expect that little environmental investments will be needed in future years. We plan to invest and manage these plants for current and long-term profitability for both capacity and energy revenues.
- *Long-term capacity resource* These plants, representing approximately 4,400 MW, are also well positioned to generate revenue for the foreseeable future, and we expect little future environmental investment. We plan to invest in this part of our fleet for long-term profitability from capacity and/or power purchase and sale agreements.
- *Near-term profit/controls* These plants, representing approximately 5,400 MW, are well positioned to generate revenue in the current environment but may require further investment in SO_2, NO_x or mercury emission controls. We expect to maintain near-term profitability and preserve the option for supply/demand recovery and/or improved gas-coal spreads in this group of plants. We may install emission controls in the future depending on environmental regulations and market conditions. See Recent Events.
- *Restore profit* This part of our fleet, representing approximately 1,600 MW, faces lower levels of profitability in the current environment. We will minimize spending, improve profitability and preserve our options for supply/demand recovery and/or improved gas-coal spreads in these plants.

Recent Events

In addition to the events described or referred to 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 our Form 10-K).

Review of Strategic Alternatives Lead to Exit of Retail Business. In October 2008, our Board of Directors initiated a process to review strategic alternatives and formed a special committee to oversee this process. In late 2008, we sold our Northeast retail C&I contracts. On May 1, 2009, we sold our Texas retail business. The sale of the retail business achieved a number of important strategic objectives for us:

- eliminated the need for approximately $2.0 billion of credit support and removed capital requirements associated with contingent collateral requirements, which lowered our overall risk profile; and
- enhanced our consolidated balance sheet and improved our liquidity position.

Table of Contents

In connection with the sale, the lawsuit related to the termination of the retail working capital facility has been dismissed. Our Board of Directors concluded its formal review of strategic alternatives in the second quarter of 2009. See Liquidity and Capital Resources and note 17 to our interim financial statements.

Environmental Matters Near-term profit/controls group. In April 2009, the New Jersey Department of Environmental Protection finalized a regulation requiring a two-phase reduction in NO_x emissions from industrial sources, including combustion turbines in New Jersey. Phase I requires reductions during high electricity demand days and runs from May 2009 through 2014. Under our initial filed compliance plan, we installed improved NO_x controls at one of our Pennsylvania facilities (upwind from New Jersey) and modified dispatch practices as necessary at our New Jersey facilities. Phase II requires the installation of emission controls on nearly all of our New Jersey combustion turbines by May 1, 2015. If we elect to install these controls, we could incur capital expenditures of up to approximately $157 million primarily during 2013 to 2015. Our initial Phase II control plan must be filed by May 1, 2010.

The Pennsylvania mercury rule generally requires mercury reductions on a facility basis in two phases, with 80% reductions by 2010 and 90% reductions by 2015. In January 2009, following a court decision overturning the less-stringent federal mercury rule, a Pennsylvania state court declared the Pennsylvania rule unlawful. The Pennsylvania Department of Environmental Protection appealed to the Pennsylvania Supreme Court, which held in June 2009 that the state rule would continue to be invalid throughout the appeal. Our capital investment plan was based on compliance with the state rule and our estimate of capital expenditures to comply primarily with the first phase of the rule was $53 million. In light of the Pennsylvania Supreme Court ruling, we have suspended work on mercury-specific control installations, except at our Shawville facility. We are continuing to evaluate our plan given that regulation of mercury at both federal and state levels is uncertain.

As we reported in our Form 10-K, the EPA is required to modify the Clean Air Act (CAIR) to cure defects in the rule identified by the District of Columbia Circuit Court of Appeals. We do not expect CAIR to be finalized until 2012 or 2013. Any spending for SO_2 or NO_x would occur over several years following finalization of these rules and would depend on market conditions.

For a discussion of other existing environmental regulations impacting our fleet, see Business Regulation Environmental Matters and Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources in Items 1 and 7, respectively, of our Form 10-K. For a discussion of pending and contingent matters related to environmental regulations, see note 11(b) to our interim financial statements.

Other. In connection with the decline in current market conditions, we evaluated each of our plants and related intangible assets for potential impairments and determined there were no impairments. See note 1(b) to our interim financial statements.

Table of Contents

Consolidated Results of Operations

Three Months Ended September 30, 2009 Compared to Three Months Ended September 30, 2008

Following the sale of our Texas retail business and commencing in the third quarter of 2009, we have four reportable segments: East Coal, East Gas, West and Other. We have presented the segment information in this report on a consistent basis for the three and nine months ended September 30, 2009 and 2008. See note 15 to our interim financial statements.

	Three Months Ended September 30,		
	2009	2008	Change
		(in millions)	
East Coal open gross margin[1]	$ 100	$ 228	$ (128)
East Gas open gross margin[1]	67	66	1
West open gross margin[1]	81	90	(9)
Other open gross margin[1]	19	17	2
Hedges and other items	(34)	85	(119)
Unrealized gains (losses) on energy derivatives	7	(40)	47
Operation and maintenance	(115)	(135)	20
General and administrative	(23)	(24)	1
Western states litigation and similar settlements		(3)	3
Gains on sales of assets and emission and exchange allowances, net	1	17	(16)
Depreciation and amortization	(68)	(78)	10
Income of equity investment, net	1	2	(1)
Debt extinguishments losses		(1)	1
Other, net		4	(4)
Interest expense	(45)	(50)	5
Interest income		5	(5)
Income tax expense	(10)	(90)	80
Income (loss) from continuing operations	(19)	93	(112)
Income (loss) from discontinued operations	4	(1,131)	1,135
Net loss	$ (15)	$ (1,038)	$ 1,023
Diluted Earnings (Loss) per Share:			
Income (loss) from continuing operations	$ (0.05)	$ 0.26	$ (0.31)
Income (loss) from discontinued operations	0.01	(3.19)	3.20
Net loss	$ (0.04)	$ (2.93)	$ 2.89

(1) Represents our segment profitability measure.

34

Table of Contents

Operational and Financial Data.

	Three Months Ended September 30, 2009		2008	
	GWh	% Economic[1]	GWh	% Economic[1]
Economic Generation[2][3]				
East Coal	5,524.6	55%	5,776.5	57%
East Gas	1,028.4	12%	766.0	9%
West	288.4	5%	1,405.9	20%
Other	11.6	1%	63.5	3%
Total	6,853.0	26%	8,011.9	29%
Commercial Capacity Factor[4]				
East Coal	89.5%		90.7%	
East Gas	97.6%		90.2%	
West	94.6%		96.9%	
Other	100.0%		81.7%	
Total	90.9%		91.6%	
Generation [3]				
East Coal	4,943.5		5,237.8	
East Gas	1,004.1		690.9	
West	272.7		1,361.7	
Other	11.6		51.9	
Total	6,231.9		7,342.3	
Open Energy Unit Margin ($/MWh)[5]				
East Coal	$ 8.70		$ 33.41	
East Gas	11.95		28.95	
West	11.00		5.14	
Other			19.27	
Weighted average total	$ 9.31		$ 27.65	

(1) Generally represents economic generation (hours) divided

by maximum generation hours (maximum plant capacity multiplied by 8,760 hours).

(2) 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.

(3) Excludes generation related to power purchase agreements, including tolling agreements.

(4) Generation divided by economic generation.

(5) Represents open energy gross margin divided by generation.

Revenues.

	Three Months Ended September 30, 2009	2008	Change
		(in millions)	
Third-party revenues	$ 532	$ 966	$ (434)[1]
Unrealized losses on energy derivatives	(25)	(6)	(19)[2]
Total revenues	$ 507	$ 960	$ (453)

(1) Decrease primarily due to (a) lower power and natural gas sales prices and (b) lower power sales volumes. These decreases were partially offset by an increase in natural gas sales volumes.

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

Table of Contents

Cost of Sales.

	Three Months Ended September 30,		
	2009	2008	Change
		(in millions)	
Third-party costs	$ 299	$ 479	$ (180)[1]
Cost of sales affiliates		1[2]	(1)
Unrealized (gains) losses on energy derivatives	(32)	34	(66)[3]
Total cost of sales	$ 267	$ 514	$ (247)

(1) Decrease primarily due to lower prices paid for natural gas.

(2) We deconsolidated Channelview on August 20, 2007. These cost of sales represent purchases of power from Channelview prior to the assets being sold in July 2008.

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

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 energy gross margin is calculated using the power sales prices received by the plants less market-based delivered fuel costs. Open energy gross margin excludes the effects of other margin, hedges and other items and unrealized gains/losses on energy derivatives. Other margin represents power purchase agreements, capacity payments, ancillary services revenues and selective commercial strategies relating to optimizing our assets.

Three Months Ended September 30,

	2009	2008 (in millions)	Change
East Coal			
Open energy gross margin	$ 43	$ 175	$ (132)(1)
Other margin	57	53	4
Open gross margin	$ 100	$ 228	$ (128)
East Gas			
Open energy gross margin	$ 12	$ 20	$ (8)(1)
Other margin	55	46	9(2)
Open gross margin	$ 67	$ 66	$ 1
West			
Open energy gross margin	$ 3	$ 7	$ (4)(3)
Other margin	78	83	(5)
Open gross margin	$ 81	$ 90	$ (9)
Other			
Open energy gross margin	$	$ 1	$ (1)
Other margin	19	16	3
Open gross margin	$ 19	$ 17	$ 2

(1) Decrease primarily due to lower unit margins (lower power prices partially offset by lower fuel costs).

(2) Increase primarily due to 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.

(3) Decrease primarily due to $6 million decrease due to the sale of Bighorn in October 2008.

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 15 to our interim financial statements for further discussion. The analyses of these items are included below.

Table of Contents

Hedges and Other Items. We enter into hedges primarily to mitigate (a) certain operational and market risks at our generation assets and (b) some of the downside risk to our earnings and cash flows. 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 power sales prices received by the plants less market-based delivered fuel costs and the actual amounts paid or received during the period.

	Three Months Ended September 30, 2009	2008	Change
		(in millions)	
Hedges and other items income (loss)	$ (34)	$ 85	$ (119)[(1)]

(1) Decrease primarily due to (a) $109 million decline on fuel hedges and (b) $42 million decline on gas transportation hedges. These decreases were partially offset by $30 million gain on 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 September 30, 2009	2008	Change
		(in millions)	
Revenues unrealized	$ (25)	$ (6)	$ (19)
Cost of sales unrealized	32	(34)	66
Net unrealized gains (losses) on energy derivatives	$ 7	$ (40)	$ 47(1)

(1) Net change primarily due to $60 million in gains due to the reversal of previously recognized unrealized losses on our energy derivatives which settled during the period, partially offset by $13 million in losses from changes in prices on our energy derivatives marked to market.

Operation and Maintenance.

	Three Months Ended September 30, 2009	2008	Change
		(in millions)	
Plant O&M	$ 78	$ 94	$ (16)[(1)]
REMA leases	15	15	
Taxes other than income and insurance	8	11	(3)
Information Technology, Risk and other salaries and benefits	6	6	
Commercial Operations	4	5	(1)
Strategic initiatives for improving plant performance	2	3	(1)
Severance	1		1
Other, net	1	1	
Operation and maintenance	$ 115	$ 135	$ (20)

(1) Decrease primarily due to (a) $7 million decrease in base O&M due to cost reduction initiatives and

decreased operations attributable to the use of our plant-specific operating model and (b) $6 million decrease in outage and project spending.

Table of Contents

General and Administrative.

	Three Months Ended September 30, 2009	2008	Change
		(in millions)	
Salaries and benefits	$ 11	$ 10	$ 1
Professional fees, contract services and information systems maintenance	4	6	(2)
Rent and utilities	4	4	
Severance	2		2
Other, net	2	4	(2)
General and administrative	$ 23	$ 24	$ (1)

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

	Three Months Ended September 30, 2009	2008	Change
		(in millions)	
Investment in and receivables from Channelview	$ 1	$ 6	$ (5)
CO_2 exchange allowances		10	(10)
Other, net		1	(1)
Gains on sales of assets and emission and exchange allowances, net	$ 1	$ 17	$ (16)

Depreciation and Amortization.

	Three Months Ended September 30, 2009	2008	Change
		(in millions)	
Depreciation on plants	$ 55	$ 54	$ 1
Other, net depreciation	4	3	1
Depreciation	59	57	2
Amortization of emission allowances	8	20	(12)[(1)]
Other, net amortization	1	1	
Amortization	9	21	(12)
Depreciation and amortization	$ 68	$ 78	$ (10)

(1) Decrease primarily due to

lower weighted average cost of SO_2 and NO_x allowances.

Income of Equity Investment, Net. This represents income/loss, which did not change significantly, from our equity method investment in Sabine Cogen, LP.

Debt Extinguishments Losses.

	Three Months Ended September 30,					
	2009	2008 (in millions)		Change		
Senior secured notes debt extinguishments losses	$	$	(1)	$	1	
Debt extinguishments losses	$	$	(1)	$	1	

Other, Net. Other, net changed by $4 million primarily due to recovery of a claim in 2008.

Interest Expense.

	Three Months Ended September 30,		
	2009	2008	Change
		(in millions)	
Fixed-rate debt	$ 52	$ 53	$ (1)
Financing fees expensed	2	3	(1)
Deferred financing costs	2	1	1
Amortization of fair value adjustment of acquired debt	(3)	(2)	(1)
Capitalized interest[1]	(8)	(4)	(4)
Other, net		(1)	1
Interest expense	$ 45[2]	$ 50[2]	$ (5)

(1) Relates primarily to scrubber projects at our Cheswick and Keystone plants, which are included in our East Coal segment.

(2) See notes 7 and 17 to our interim financial statements regarding certain debt and related interest expense classified in discontinued operations.

Interest Income.

	Three Months Ended September 30,		
	2009	2008	Change
		(in millions)	
Interest on temporary cash investments	$	$ 3	$ (3)
Net margin deposits		1	(1)
Other, net		1	(1)

Interest income	$	$ 5	$ (5)

Income Tax Expense (Benefit). See note 9 to our interim financial statements.
Income from Discontinued Operations. See note 17 to our interim financial statements.

Table of Contents

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

	Nine Months Ended September 30, 2009	2008	Change
	(in millions)		
East Coal open gross margin[1]	$ 312	$ 714	$ (402)
East Gas open gross margin[1]	155	146	9
West open gross margin[1]	114	138	(24)
Other open gross margin[1]	48	42	6
Hedges and other items	(108)	164	(272)
Unrealized gains (losses) on energy derivatives	(30)	58	(88)
Operation and maintenance	(429)	(456)	27
General and administrative	(80)	(86)	6
Western states litigation and similar settlements		(37)	37
Gains on sales of assets and emission and exchange allowances, net	21	40	(19)
Depreciation and amortization	(203)	(244)	41
Income of equity investment, net	1	3	(2)
Debt extinguishments gains (losses)	1	(2)	3
Other, net		4	(4)
Interest expense	(137)	(152)	15
Interest income	1	19	(18)
Income tax (expense) benefit	106	(163)	269
Income (loss) from continuing operations	(228)	188	(416)
Income (loss) from discontinued operations	865	(490)	1,355
Net income (loss)	$ 637	$ (302)	$ 939
Diluted Earnings (Loss) per Share:			
Income (loss) from continuing operations	$ (0.65)	$ 0.53	$ (1.18)
Income (loss) from discontinued operations	2.46	(1.38)	3.84
Net income (loss)	$ 1.81	$ (0.85)	$ 2.66

(1) Represents our segment profitability measure.

Table of Contents

Operational and Financial Data.

	Nine Months Ended September 30,			
	2009		2008	
	GWh	% Economic	GWh	% Economic
Economic Generation				
East Coal	17,886.4	60%	20,464.7	68%
East Gas	1,701.7	7%	1,178.8	5%
West	576.5	3%	1,952.9	9%
Other	74.7	1%	70.4	2%
Total	20,239.3	26%	23,666.8	31%
Commercial Capacity Factor				
East Coal	82.3%		85.7%	
East Gas	96.3%		90.8%	
West	86.3%		93.9%	
Other	98.9%		81.7%	
Total	83.6%		86.6%	
Generation				
East Coal	14,711.6		17,529.0	
East Gas	1,638.4		1,070.6	
West	497.7		1,834.0	
Other	73.9		57.5	
Total	16,921.6		20,491.1	
Open Energy Unit Margin ($/MWh)				
East Coal	$ 12.10		$ 34.91	
East Gas	10.99		37.36	
West	24.11		NM(1)	
Other			17.39	
Weighted average total	$ 12.29		$ 31.82	

(1) NM is not meaningful.

Revenues.

Nine Months Ended September 30,

	2009	2008 (in millions)	Change
Third-party revenues	$ 1,414	$ 2,614	$ (1,200)[1]
Revenues affiliates		253[2]	(253)
Unrealized losses on energy derivatives	(51)	(13)	(38)[3]
Total revenues	$ 1,363	$ 2,854	$ (1,491)

(1) Decrease primarily due to (a) lower power and natural gas sales prices and (b) lower power sales volumes. These decreases were partially offset by an increase in natural gas sales volumes.

(2) We deconsolidated Channelview on August 20, 2007. These revenues represent sales of fuel to Channelview prior to the assets being sold in July 2008.

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

Table of Contents

Cost of Sales.

	Nine Months Ended September 30, 2009	2008	Change
		(in millions)	
Third-party costs	$ 893	$ 1,592	$ (699)[1]
Cost of sales affiliates		71[2]	(71)
Unrealized gains on energy derivatives	(21)	(71)	50[3]
Total cost of sales	$ 872	$ 1,592	$ (720)

(1) Decrease primarily due to (a) lower prices paid for natural gas and (b) lower natural gas and coal volumes purchased. These decreases were partially offset by (a) higher prices paid for coal and (b) loss on market adjustments to inventory.

(2) We deconsolidated Channelview on August 20, 2007. These cost of sales represent purchases of power from Channelview prior to the assets being sold in July 2008.

(3)

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

Open Gross Margin.

	Nine Months Ended September 30, 2009	2008 (in millions)	Change
East Coal			
Open energy gross margin	$ 178	$ 612	$ (434)(1)
Other margin	134	102	32(2)
Open gross margin	$ 312	$ 714	$ (402)
East Gas			
Open energy gross margin	$ 18	$ 40	$ (22)(1)
Other margin	137	106	31(3)
Open gross margin	$ 155	$ 146	$ 9
West			
Open energy gross margin	$ 12	$ (1)	$ 13(4)
Other margin	102	139	(37)(5)
Open gross margin	$ 114	$ 138	$ (24)
Other			
Open energy gross margin	$	$ 1	$ (1)
Other margin	48	41	7
Open gross margin	$ 48	$ 42	$ 6

(1) Decrease primarily due to lower unit margins (lower power prices partially offset by lower fuel costs).

(2)

Increase primarily due to higher RPM capacity payments. This increase was partially offset by lower ancillary payments.

(3) Increase primarily due to higher RPM capacity payments.

(4) Increase primarily due to higher unit margins (lower fuel costs partially offset by lower power prices). This increase was partially offset by a decrease in economic generation.

(5) Decrease primarily due to reduced selective commercial strategies.

Hedges and Other Items.

	Nine Months Ended September 30, 2009	2008	Change
	(in millions)		
Hedges and other items income (loss)	$ (108)	$ 164	$ (272)[1]

(1) Decrease primarily due to (a) $258 million decline on fuel

hedges, (b) $67 million loss on market adjustments to inventory, (c) $34 million decline on gas transportation hedges and (d) $26 million loss primarily related to payments to reduce fixed price coal commitments for future periods. These decreases were partially offset by $81 million gain on hedges of generation.

Table of Contents

Unrealized Gains (Losses) on Energy Derivatives.

	Nine Months Ended September 30,		
	2009	2008	Change
	(in millions)		
Revenues unrealized	$ (51)	$ (13)	$ (38)
Cost of sales unrealized	21	71	(50)
Net unrealized gains (losses) on energy derivatives	$ (30)	$ 58	$ (88)(1)

(1) Net change primarily due to $107 million in losses from changes in prices on our energy derivatives marked to market, partially offset by $19 million in gains due to reversal of previously recognized unrealized losses on energy derivatives which settled during the period.

Operation and Maintenance.

	Nine Months Ended September 30,		
	2009	2008	Change
	(in millions)		
Plant O&M	$ 305	$ 332	$ (27)(1)
REMA leases	45	45	
Taxes other than income and insurance	30	35	(5)
Information Technology, Risk and other salaries and benefits	25	19	6
Commercial Operations	13	15	(2)
Severance	5		5
Strategic initiatives for improving plant performance	3	7	(4)
Bighorn (non-plant operations)		5	(5)

Other, net		3		(2)		5
Operation and maintenance	$	429	$	456	$	(27)

(1) Decrease primarily due to (a) $17 million decrease in base O&M due to decreased operations attributable to the use of our plant-specific operating model and cost reduction initiatives and (b) $5 million decrease due to the sale of Bighorn in October 2008.

General and Administrative.

	Nine Months Ended September 30,					
	2009		2008		Change	
			(in millions)			
Salaries and benefits	$	42	$	43	$	(1)
Professional fees, contract services and information systems maintenance		16		21		(5)
Rent and utilities		11		11		
Legal costs		3		4		(1)
Severance		3				3
Other, net		5		7		(2)
General and administrative	$	80	$	86	$	(6)

Western States Litigation and Similar Settlements. See note 11(a) to our consolidated financial statements in our Form 10-K.

Table of Contents

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

	Nine Months Ended September 30, 2009	2008 (in millions)	Change
CO_2 exchange allowances	$ 10	$ 36	$ (26)
SO_2 and NO_x emission allowances	7	1	6
Bighorn plant	3		3
Investment in and receivables from Channelview	1	1	
Other, net		2	(2)
Gains on sales of assets and emission and exchange allowances, net	$ 21	$ 40	$ (19)

Depreciation and Amortization.

	Nine Months Ended September 30, 2009	2008 (in millions)	Change
Depreciation on plants	$ 166	$ 171	$ (5)
Other, net depreciation	12	11	1
Depreciation	178	182	(4)
Amortization of emission allowances	22	59	(37)(1)
Other, net amortization	3	3	
Amortization	25	62	(37)
Depreciation and amortization	$ 203	$ 244	$ (41)

(1) Decrease primarily due to (a) lower weighted average cost of SO_2 allowances and (b) decrease in SO_2 allowances used.

Income of Equity Investment, Net. This represents income/loss, which did not change significantly, from our equity method investment in Sabine Cogen, LP.

Debt Extinguishments Gains (Losses).

Nine Months Ended September 30,

	2009	2008 (in millions)	Change
Senior secured notes debt extinguishments gains (losses)	$ 2	$ (1)	$ 3
Deferred financing costs accelerated amortization due to extinguishments	(1)	(1)	
Debt extinguishments gains (losses)	$ 1	$ (2)	$ 3

Other, Net. Other, net changed $4 million primarily due to recovery of a claim in 2008.

Table of Contents

Interest Expense.

	Nine Months Ended September 30, 2009	2008	Change
	(in millions)		
Fixed-rate debt	$ 157	$ 159	$ (2)
Financing fees expensed	5	7	(2)
Deferred financing costs	5	4	1
Amortization of fair value adjustment of acquired debt	(9)	(8)	(1)
Capitalized interest[1]	(22)	(11)	(11)
Other, net	1	1	
Interest expense	$ 137[2]	$ 152[2]	$ (15)

(1) Relates primarily to scrubber projects at our Cheswick and Keystone plants, which are included in our East Coal segment.

(2) See notes 7 and 17 to our interim financial statements regarding certain debt and related interest expense classified in discontinued operations.

Interest Income.

	Nine Months Ended September 30, 2009	2008	Change
	(in millions)		
Interest on temporary cash investments	$ 2	$ 13	$ (11)
Net margin deposits		5	(5)
Other, net	(1)	1	(2)

Interest income	$	1	$	19	$	(18)

Income Tax Expense (Benefit). See note 9 to our interim financial statements.

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

Liquidity and Capital Resources

Our goal of establishing and maintaining financial flexibility remains unchanged. We are committed to a strong balance sheet and ample liquidity that will enable us to avoid distress in cyclical troughs and to access capital markets throughout the cycle for value-creation opportunities. We believe our liquidity has and continues to exceed the level required to achieve this goal. As discussed below, we have used and expect to continue to use some of our cash and cash equivalents to reduce debt. We also deployed some of our cash to margin deposits by replacing outstanding letters of credit, which together with our reduction of secured debt, improved our revolver s financial maintenance covenant ratio. As of October 27, 2009, we had total available liquidity of $1.7 billion, comprised of unused borrowing capacity, letters of credit capacity and cash and cash equivalents.

Debt Reduction. Our goal for gross debt (total GAAP debt plus our RRI Energy Mid-Atlantic Power Holdings, LLC (REMA) operating leases) is $1.25 billion to $1.75 billion. The comparable target for total GAAP debt, based on the current balance for our REMA leases of $423 million, is approximately $800 million to $1.3 billion. 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 October 2009 we completed a tender offer and purchased for cash $127 million principal amount of our senior secured notes and $2 million principal amount of PEDFA bonds. Total consideration paid to the note and bond holders was $132 million.

During the second and third quarters of 2009, we also purchased $61 million principal amount of our senior secured notes on the open market. In November 2009, we purchased an additional $31 million principal amount of our senior secured notes on the open market.

On May 1, 2009, we sold our Texas retail business for $287.5 million in cash plus the value of the net working capital (currently estimated at $78 million). We offered a portion of the net proceeds to holders of our senior secured notes and PEDFA bonds and purchased $261 million at par in the second and third quarters of 2009. See Recent Events and note 17 to our interim financial statements.

Table of Contents

In the future, we could use a variety of means to achieve our gross debt goal, including retirements due to maturities (Orion Power Holdings, Inc. s $400 million senior unsecured notes due in May 2010), open market purchases, call provisions and tender offers.

Cash Flows. During the nine months ended September 30, 2009, we used $275 million in operating cash flows from continuing operations, including the net changes in margin deposits of $240 million (cash outflow). See Historical Cash Flows for further detail of our cash flows from operating activities and explanation of our $107 million and $55 million use of cash from investing activities from continuing operations and use of cash from financing activities from continuing operations, respectively, during the nine months ended September 30, 2009.

See note 9 to our interim financial statements regarding an expected income tax cash payment of approximately $60 to $65 million relating to California-related matters.

We continue to monitor our business and hedging with the goal of at least breaking even on a free cash flow basis in the event of a sustained depressed commodity price environment. Based on our assessment of the economic environment and volatility in commodity markets, we have hedged, with swaps, approximately 30% and 29% 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 5% and 12% of this estimated power generation for 2010 and 2011, respectively, with options to retain the energy margin upside for market improvements. We consider free cash flow to be operating cash flow from continuing operations, adjusted for capital expenditures, net sales (purchases) of emission and exchange allowances and changes in net margin deposits.

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, notes 6 and 12(a) to our consolidated financial statements in our Form 10-K and note 7 to our interim financial statements.

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.

Table of Contents

Off-Balance Sheet Arrangements

As of September 30, 2009, we have no off-balance sheet arrangements.

Historical Cash Flows

Cash Flows Operating Activities

	Nine Months Ended September 30, 2009	2008	Change
	(in millions)		
Operating income (loss)	$ (200)	$ 479	$ (679)
Depreciation and amortization	203	244	(41)
Net changes in energy derivatives	30(1)	(58) (2)	88
Gains on sales of assets and emission allowances, net	(21)	(40)	19
Western states litigation and similar settlements		37	(37)
Western states litigation and similar settlements payments	(3)		(3)
Change in accounts and notes receivable and accounts payable, net	108	(36)	144
Changes in notes, receivables and payables with affiliate, net		9	(9)
Change in inventory	(1)	(42)	41
Margin deposits, net	(240)	29	(269)
Net option premiums purchased	(30)		(30)
Settlements of exchange transactions prior to contractual period(3)	3	(5)	8
Prepaid lease obligation	(19)	(18)	(1)
Construction deposit refund	15		15
Interest payments, net of capitalized interest	(89)	(103)	14
Income tax payments, net of refunds	(5)	(2)	(3)
Pension contributions	(20)	(5)	(15)
Other, net	(6)	16	(22)
Net cash provided by (used in) continuing operations from operating activities	(275)	505	(780)
Net cash provided by (used in) discontinued operations from operating activities	534	(237)	771
Net cash provided by operating activities	$ 259	$ 268	$ (9)

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

(2) Includes unrealized gains on energy derivatives of

$58 million.

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

Cash Flows Investing Activities

	Nine Months Ended September 30, 2009	2008	Change
	(in millions)		
Capital expenditures	$ (158)	$ (191)	$ 33
Proceeds from sales of assets	36(1)	18	18
Proceeds from sales of emission allowances	19	39	(20)
Purchases of emission allowances	(8)	(26)	18
Restricted cash		(3)	3
Other, net	4	4	
Net cash used in continuing operations from investing activities	(107)	(159)	52
Net cash provided by (used in) discontinued operations from investing activities	314	(25)	339
Net cash provided by (used in) investing activities	$ 207	$ (184)	$ 391

(1) Includes $35 million previously held in escrow and released to us relating to the sale of the Channelview plant in July 2008.

Table of Contents

Cash Flows Financing Activities

	Nine Months Ended September 30, 2009	2008 (in millions)	Change
Purchases of senior secured notes	$ (59)	$ (58)	$ (1)
Proceeds from issuance of stock	4	14	(10)
Payments of debt extinguishments		(1)	1
Net cash used in continuing operations from financing activities	(55)	(45)	(10)
Net cash used in discontinued operations from financing activities	(261)		(261)
Net cash used in financing activities	$ (316)	$ (45)	$ (271)

New Accounting Pronouncements, Significant Accounting Policies and Critical Accounting Estimates

New Accounting Pronouncements

See note 1 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.

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, 4 and 5 to our interim financial statements.

Non-Trading Market Risks

Commodity Price Risk

As of September 30, 2009, the fair values of the contracts related to our net non-trading derivative assets and liabilities are:

Source of Fair Value	Twelve Months Ending September 30, 2010	Remainder of 2010	2011	2012	2013	2014 and thereafter	Total fair value
				(in millions)			
Prices actively quoted (Level 1)	$ 28	$ 6	$ 25	$	$	$	$ 59
Prices provided by other external sources (Level 2)	(47)	(9)	(36)	(12)	1		(103)
Prices based on models and other valuation methods (Level 3)	(71)	(1)					(72)
Total mark-to-market non-trading derivatives	$ (90)	$ (4)	$ (11)	$ (12)	$ 1	$	$ (116)

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. In addition, we have committed volumes under some coal contracts through 2010 and 2011 for which the contract prices are subject to negotiation prior to the beginning of each year. For further discussion of how we arrive at these fair values, see note 2(d) to our consolidated financial statements in our Form 10-K, 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)	
September 30, 2009	10% increase	$ (46)	$ (46)
December 31, 2008	10% decrease	(5)	(5)

Interest Rate Risk

As of September 30, 2009 and December 31, 2008, we have no variable rate debt outstanding. We earn interest income, for which the interest rates vary, on our cash and cash equivalents and net margin deposits. During the nine months ended September 30, 2009 and twelve months ended December 31, 2008, we had no variable rate interest expense and our interest income was $2 million and $20 million, respectively.

If interest rates decreased by one percentage point from their September 30, 2009 and December 31, 2008 levels, the fair values of our fixed rate debt from continuing operations would have increased by $145 million and $110 million, respectively.

Trading Market Risks

As of September 30, 2009, 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:

Source of Fair Value	Twelve Months Ending September 30, 2010	Remainder of 2010	2011	2012	2013	2014 and thereafter	Total fair value
				(in millions)			
Prices actively quoted (Level 1)	$ 29	$ 2	$	$	$	$	$ 31
Prices provided by other external sources (Level 2)							
Prices based on models and other valuation methods (Level 3)	(5)						(5)
Total	$ 24	$ 2	$	$	$	$	$ 26

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
		(in millions)		
Realized	$ 7	$ 3	$ 25	$ 12
Unrealized	(2)	28	(4)	2
Total	$ 5	$ 31	$ 21	$ 14

An analysis of these net derivative assets and liabilities is:

	Nine Months Ended September 30,	
	2009	2008
	(in millions)	
Fair value of contracts outstanding, beginning of period	$ 30	$ 19
Contracts realized or settled	(25)[(1)]	(13)[(2)]
	21	15

Changes in fair values attributable to market price and other market changes				
Fair value of contracts outstanding, end of period	$	26	$	21

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

(2) Amount includes realized gain of $12 million and deferred settlements of $1 million.

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

	2009[1]	2008
	(in millions)	
As of September 30	$ 1	$ 8
Three months ended September 30:		
Average	1	8
High	1	12
Low	1	1
Nine months ended September 30:		
Average	2	13
High	4	
Low	1	5

(1) The major parameters for calculating daily value-at-risk remain the same during 2009 as disclosed in Quantitative and Qualitative Disclosures About Market Risk in Item 7A of our Form 10-K.

Fair Value Measurements

We apply recurring fair value measurements to our derivative assets and liabilities. See note 3 to our interim financial statements. Derivative instruments classified as Level 2 primarily include over-the-counter (OTC) derivative instruments such as generic swaps and forwards. The fair value measurements of these derivative assets and liabilities are based largely on unadjusted indicative quoted prices for similar assets or liabilities from independent brokers in active markets. 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. 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.

Fair value for energy derivatives is further derived from credit adjustments. Derivative assets are discounted 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.

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, volatilities and correlations as well as other relevant factors as may be deemed appropriate. 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.

Table of Contents

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, have evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (1934 Act)) as of September 30, 2009, the end of the period covered by this Form 10-Q. Based on this evaluation, our chief executive officer and chief financial officer concluded that, as of September 30, 2009, our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the 1934 Act) during the period ended September 30, 2009, 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 11 to our interim financial statements in this Form 10-Q.

ITEM 6. EXHIBITS

Exhibits.

See Index of Exhibits.

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

	RRI ENERGY, INC. (Registrant)
November 5, 2009	By: /s/ Thomas C. Livengood Thomas C. Livengood **Senior Vice President and Controller** **(Duly Authorized Officer and Chief Accounting Officer)**

Table of Contents

INDEX OF EXHIBITS

Exhibits not incorporated by reference to a prior filing are designated by a cross (+); all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. 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		
3.3	Certificate of Ownership and Merger merging a wholly-owned subsidiary into registrant pursuant to Section 253 of the General Corporation Law of the State of Delaware, effective as of May 2, 2009	RRI Energy, Inc. s Quarterly Report on Form 10-Q for the period ended March 31, 2009	1-16455	3.3
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	Sixth Supplemental Indenture relating to the 6.75% Senior Secured Notes due 2014, among RRI Energy, Inc., The Guarantors listed therein			

	and Wilmington Trust Company, dated as of June 1, 2009
+10.2	Third Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2001A, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of June 1, 2009
+10.3	Third Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002A, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of June 1, 2009
+10.4	Third Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2002B, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of June 1, 2009

Table of Contents

Exhibit Number	Document Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference
+10.5	Third Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2003A, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of June 1, 2009			
+10.6	Fourth Supplemental Guarantee Agreement relating to Pennsylvania Economic Development Financing Authority s Exempt Facilities Revenue Bonds (Reliant Energy Seward, LLC Project), Series 2004A, among RRI Energy, Inc., the Subsidiary Guarantors as defined in the Guarantee Agreement and The Bank of New York Trust Company, N.A., as trustee, dated as of June 1, 2009			
+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			