NRG ENERGY, INC.
Form 10-Q
August 02, 2010

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

þ **Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the quarterly period ended: June 30, 2010

o **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
Commission File Number: 001-15891
NRG Energy, Inc.
(Exact name of registrant as specified in its charter)

Delaware	**41-1724239**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
211 Carnegie Center, Princeton, New Jersey	**08540**
(Address of principal executive offices)	(Zip Code)

(609) 524-4500
(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.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o **No** þ

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court.

Yes þ **No** o

As of July 29, 2010, there were 253,184,870 shares of common stock outstanding, par value $0.01 per share.

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CAUTIONARY STATEMENT REGARDING FORWARD LOOKING INFORMATION

This Quarterly Report on Form 10-Q of NRG Energy, Inc., or NRG or the Company, includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. The words believes, projects, anticipates, plans, expects, intends, estimates and similar expressions are intended to identify forward-lo statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause NRG s actual results, performance and achievements, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. These factors, risks and uncertainties include the factors described under Risks Factors Related to NRG Energy, Inc. in Part I, Item 1A, of the Company s Annual Report on Form 10-K, for the year ended December 31, 2009, including the following:

General economic conditions, changes in the wholesale power markets and fluctuations in the cost of fuel;

Volatile power supply costs and demand for power;

Hazards customary to the power production industry and power generation operations such as fuel and electricity price volatility, unusual weather conditions, catastrophic weather-related or other damage to facilities, unscheduled generation outages, maintenance or repairs, unanticipated changes to fuel supply costs or availability due to higher demand, shortages, transportation problems or other developments, environmental incidents, or electric transmission or gas pipeline system constraints and the possibility that NRG may not have adequate insurance to cover losses as a result of such hazards;

The effectiveness of NRG s risk management policies and procedures, and the ability of NRG s counterparties to satisfy their financial commitments;

Counterparties collateral demands and other factors affecting NRG s liquidity position and financial condition;

NRG s ability to operate its businesses efficiently, manage capital expenditures and costs tightly, and generate earnings and cash flows from its asset-based businesses in relation to its debt and other obligations;

NRG s ability to enter into contracts to sell power and procure fuel on acceptable terms and prices;

The liquidity and competitiveness of wholesale markets for energy commodities;

Government regulation, including compliance with regulatory requirements and changes in market rules, rates, tariffs and environmental laws and increased regulation of carbon dioxide and other greenhouse gas emissions;

Price mitigation strategies and other market structures employed by ISOs or RTOs that result in a failure to adequately compensate NRG s generation units for all of its costs;

NRG s ability to borrow additional funds and access capital markets, as well as NRG s substantial indebtedness and the possibility that NRG may incur additional indebtedness going forward;

Operating and financial restrictions placed on NRG and its subsidiaries that are contained in the indentures governing NRG s outstanding notes, in NRG s Senior Credit Facility, and in debt and other agreements of certain of NRG subsidiaries and project affiliates generally;

NRG s ability to implement its *Repowering*NRG strategy of developing and building new power generation facilities, including new nuclear, wind and solar projects;

NRG s ability to implement its econrg strategy of finding ways to meet the challenges of climate change, clean air and protecting natural resources while taking advantage of business opportunities;

NRG s ability to implement its *FOR*NRG strategy of increasing the return on invested capital through operational performance improvements and a range of initiatives at plants and corporate offices to reduce costs or generate revenues;

NRG s ability to achieve its strategy of regularly returning capital to shareholders;

Reliant Energy s ability to maintain market share;

NRG s ability to successfully evaluate investments in new business and growth initiatives; and

NRG s ability to successfully integrate and manage acquired businesses.

Forward-looking statements speak only as of the date they were made, and NRG undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors that could cause NRG s actual results to differ materially from those contemplated in any forward-looking statements included in this Quarterly Report on Form 10-Q should not be construed as exhaustive.

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

Baseload capacity	Electric power generation capacity normally expected to serve loads on an around-the-clock basis throughout the calendar year
BTU	British Thermal Unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CATR	Clean Air Transport Rule
Capital Allocation Plan	Share repurchase program
Capital Allocation Program	NRG s plan of allocating capital between debt reduction, reinvestment in the business, and share repurchases through the Capital Allocation Plan
C&I	Commercial, industrial and governmental/institutional
CFTC	U.S. Commodity Futures Trading Commission
CO_2	Carbon dioxide
CPS	CPS Energy
CSF Debt	CSF I and CSF II issued notes and preferred interest, individually referred to as CSF I Debt and CSF II Debt
CSRA	Credit Sleeve Reimbursement Agreement with Merrill Lynch in connection with acquisition of Reliant Energy, as hereinafter defined
CSRA Amendment	Amendment of the existing CSRA with Merrill Lynch which became effective October 5, 2009
DNREC	Delaware Department of Natural Resources and Environmental Control
ERCOT	Electric Reliability Council of Texas, the Independent System Operator and the regional reliability coordinator of the various electricity systems within Texas
Exchange Act	The Securities Exchange Act of 1934, as amended
Expected Baseload Generation	The net baseload generation limited by economic factors (relationship between cost of generation and market price) and reliability factors (scheduled and unplanned outages)

FASB	Financial Accounting Standards Board the designated organization for establishing standards for financial accounting and reporting
FERC	Federal Energy Regulatory Commission
Funded Letter of Credit Facility	NRG s $1.3 billion term loan-backed fully funded senior secured letter of credit facility, of which $500 million matures on February 1, 2013, and $800 million matures on August 31, 2015, and is a component of NRG s Senior Credit Facility
GHG	Greenhouse Gases
GWh	Gigawatt hour
IGCC	Integrated Gasification Combined Cycle
ISO	Independent System Operator, also referred to as Regional Transmission Organizations, or RTO
ISO-NE	ISO New England Inc.
kV	Kilovolts
kW	Kilowatts

kWh	Kilowatt-hours
LIBOR	London Inter-Bank Offer Rate
LTIP	Long-Term Incentive Plan
MACT	Maximum Achievable Control Technology
Mass	Residential and small business
Merit Order	A term used for the ranking of power stations in order of ascending marginal cost
MIBRAG	Mitteldeutsche Braunkohlengesellschaft mbH
MMBtu	Million British Thermal Units
MW	Megawatts
MWh	Saleable megawatt hours net of internal/parasitic load megawatt-hours
NAAQS	National Ambient Air Quality Standards
NINA	Nuclear Innovation North America LLC
NO_x	Nitrogen oxide
NPNS	Normal Purchase Normal Sale
NRC	U.S. Nuclear Regulatory Commission
NYISO	New York Independent System Operator
OCI	Other comprehensive income
Phase II 316(b) Rule	A section of the Clean Water Act regulating cooling water intake structures
PJM	PJM Interconnection, LLC
PJM market	The wholesale and retail electric market operated by PJM primarily in all or parts of Delaware, the District of Columbia, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia
PPA	Power Purchase Agreement
PUCT	Public Utility Commission of Texas
Reliant Energy	NRG s retail business in Texas purchased on May 1, 2009, from Reliant Energy, Inc. which is now known as RRI Energy, Inc., or RRI

Repowering	Technologies utilized to replace, rebuild, or redevelop major portions of an existing electrical generating facility, not only to achieve a substantial emissions reduction, but also to increase facility capacity, and improve system efficiency
*Repowering*NRG	NRG s program designed to develop, finance, construct and operate new, highly efficient, environmentally responsible capacity
RERH	RERH Holding, LLC and its subsidiaries
Revolving Credit Facility	NRG s $875 million senior secured revolving credit facility, which matures on August 31, 2015, and is a component of NRG s Senior Credit Facility
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
ROIC	Return on invested capital
RRI	RRI Energy, Inc. (formerly Reliant Energy, Inc.)
Sarbanes-Oxley	Sarbanes-Oxley Act of 2002, as amended
SEC	United States Securities and Exchange Commission

Securities Act	The Securities Act of 1933, as amended
Senior Credit Facility	NRG s senior secured facility, which is comprised of a Term Loan Facility, an $875 million Revolving Credit Facility and a $1.3 billion Funded Letter of Credit Facility
Senior Notes	The Company s $5.4 billion outstanding unsecured senior notes consisting of $1.2 billion of 7.25% senior notes due 2014, $2.4 billion of 7.375% senior notes due 2016, $1.1 billion of 7.375% senior notes due 2017, and $700 million of 8.5% senior notes due 2019
SO_2	Sulfur dioxide
STP	South Texas Project nuclear generating facility located near Bay City, Texas in which NRG owns a 44% Interest
STPNOC	South Texas Project Nuclear Operating Company
TANE	Toshiba America Nuclear Energy Corporation
TANE Facility	NINA s $500 million credit facility with TANE which matures on February 24, 2012
TEPCO	The Tokyo Electric Power Company of Japan, Inc.
Term Loan Facility	A senior first priority secured term loan, of which approximately $975 million matures on February 1, 2013 and $1.0 billion matures on August 31, 2015, and is a component of NRG s Senior Credit Facility
TNEA	TEPCO Nuclear Energy America LLC
Tonnes	Metric tonnes, which are units of mass or weight in the metric system each equal to 2,205lbs and are the global measurement for GHG
TWh	Terawatt hour
U.S.	United States of America
U.S. DOE	United States Department of Energy
U.S. EPA	United States Environmental Protection Agency
U.S. GAAP	Accounting principles generally accepted in the United States
VaR	Value at Risk

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ACCOUNTING PRONOUNCEMENTS

The FASB has established the FASB Accounting Standards Codification, or ASC, as the source of authoritative U.S. GAAP. The FASB issues updates to the ASC through Accounting Standards Updates, or ASUs. The following ASC topics and ASUs are referenced in this report:

ASC 280	ASC-280, *Segment Reporting*
ASC 450	ASC-450, *Contingencies*
ASC 740	ASC-740, *Income Taxes*
ASC 805	ASC-805, *Business Combinations*
ASC 810	ASC-810, *Consolidation*
ASC 815	ASC-815, *Derivatives and Hedging*
ASC 820	ASC-820, *Fair Value Measurements and Disclosures*
ASC 980	ASC-980, *Regulated Operations*
ASU 2009-15	ASU No. 2009-15, *Accounting for Own-Share Lending Arrangements in Contemplation of Convertible Debt Issuance or Other Financing*
ASU 2009-17	ASU No. 2009-17, *Consolidations: Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities*
ASU 2010-02	ASU No. 2010-02, *Consolidation (Topic 810): Accounting and Reporting for Decreases in Ownership of a Subsidiary a Scope Clarification*
ASU 2010-06	ASU No. 2010-06, *Fair Value Measurement and Disclosures: Improving Disclosures about Fair Value Measurements*
ASU 2010-09	ASU No. 2010-09, *Subsequent Events (Topic 815): Amendments to Certain Recognition and Disclosure Requirements*
ASU 2010-10	ASU No. 2010-10, *Consolidation (Topic 810): Amendments for Certain Investment Funds*

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PART I FINANCIAL INFORMATION
ITEM 1 CONDENSED CONSOLIDATED FINANCIAL STATEMENTS AND NOTES
NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
(In millions, except for per share amounts)	**2010**	**2009**	**2010**	**2009**
Operating Revenues				
Total operating revenues	$2,133	$2,237	$4,348	$3,895
Operating Costs and Expenses				
Cost of operations	1,329	1,242	2,968	2,008
Depreciation and amortization	208	213	410	382
Selling, general and administrative	139	131	269	214
Acquisition-related transaction and integration costs		23		35
Development costs	13	9	22	22
Total operating costs and expenses	1,689	1,618	3,669	2,661
Gain on sale of assets			23	
Operating Income	444	619	702	1,234
Other Income/(Expense)				
Equity in earnings of unconsolidated affiliates	11	5	25	27
Gain on sale of equity method investment		128		128
Other income/(expense), net	19	(11)	23	(14)
Interest expense	(147)	(159)	(300)	(297)
Total other expense	(117)	(37)	(252)	(156)
Income Before Income Taxes	327	582	450	1,078
Income tax expense	117	150	182	448
Net Income	210	432	268	630
Less: Net loss attributable to noncontrolling interest	(1)	(1)	(1)	(1)
Net income attributable to NRG Energy, Inc.	211	433	269	631
Dividends for preferred shares	3	7	5	21
Income Available for NRG Energy, Inc. Common Stockholders	$ 208	$ 426	$ 264	$ 610
Earnings per share attributable to NRG Energy, Inc. Common Stockholders				
Weighted average number of common shares outstanding basic	255	253	254	245
Net Income per Weighted Average Common Share basic	$ 0.82	$ 1.68	$ 1.04	$ 2.49

Weighted average number of common shares outstanding diluted	256	275	256	275
Net Income per Weighted Average Common Share diluted	$ 0.81	$ 1.56	$ 1.03	$ 2.27

See notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions, except shares)	June 30, 2010 (unaudited)	December 31, 2009
ASSETS		
Current Assets		
Cash and cash equivalents	$ 2,168	$ 2,304
Funds deposited by counterparties	310	177
Restricted cash	13	2
Accounts receivable trade, less allowance for doubtful accounts of $21 and $29, respectively	909	876
Inventory	535	541
Derivative instruments valuation	1,800	1,636
Cash collateral paid in support of energy risk management activities	391	361
Prepayments and other current assets	243	311
Total current assets	6,369	6,208
Property, plant and equipment, net of accumulated depreciation of $3,414 and $3,052, respectively	11,793	11,564
Other Assets		
Equity investments in affiliates	394	409
Note receivable affiliate and capital leases, less current portion	434	504
Goodwill	1,716	1,718
Intangible assets, net of accumulated amortization of $862 and $648, respectively	1,626	1,777
Nuclear decommissioning trust fund	360	367
Derivative instruments valuation	910	683
Restricted cash supporting funded letter of credit facility	1,300	
Other non-current assets	201	148
Total other assets	6,941	5,606
Total Assets	$ 25,103	$ 23,378
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 179	$ 571
Accounts payable	690	697
Derivative instruments valuation	1,484	1,473
Deferred income taxes	244	197
Cash collateral received in support of energy risk management activities	310	177
Accrued expenses and other current liabilities	623	647
Total current liabilities	3,530	3,762

Other Liabilities		
Long-term debt and capital leases	7,991	7,847
Funded letter of credit	1,300	
Nuclear decommissioning reserve	309	300
Nuclear decommissioning trust liability	234	255
Deferred income taxes	1,768	1,783
Derivative instruments valuation	433	387
Out-of-market contracts	258	294
Other non-current liabilities	1,002	806
Total non-current liabilities	13,295	11,672
Total Liabilities	16,825	15,434
3.625% convertible perpetual preferred stock (at liquidation value, net of issuance costs)	248	247
Commitments and Contingencies		
Stockholders Equity		
Preferred stock (at liquidation value, net of issuance costs)		149
Common stock	3	3
Additional paid-in capital	5,311	4,948
Retained earnings	3,596	3,332
Less treasury stock, at cost 50,625,606 and 41,866,451 shares, respectively	(1,373)	(1,163)
Accumulated other comprehensive income	476	416
Noncontrolling interest	17	12
Total Stockholders Equity	8,030	7,697
Total Liabilities and Stockholders Equity	$ 25,103	$ 23,378

See notes to condensed consolidated financial statements.

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

(In millions) Six months ended June 30,	2010	2009
Cash Flows from Operating Activities		
Net income	$ 268	$ 630
Adjustments to reconcile net income to net cash provided by operating activities:		
Distributions and equity in earnings of unconsolidated affiliates	(9)	(27)
Depreciation and amortization	410	382
Provision for bad debts	22	9
Amortization of nuclear fuel	19	19
Amortization of financing costs and debt discount/premiums	15	21
Amortization of intangibles and out-of-market contracts	1	15
Changes in deferred income taxes and liability for unrecognized tax benefits	179	445
Changes in nuclear decommissioning trust liability	9	15
Changes in derivatives	(55)	(368)
Changes in collateral deposits supporting energy risk management activities	(30)	245
Gain on sale of assets, net	(11)	(1)
Gain on sale of equity method investment		(128)
Loss/(gain) on sale of emission allowances	3	(9)
Gain recognized on settlement of pre-existing relationship		(31)
Amortization of unearned equity compensation	15	13
Changes in option premiums collected, net of acquisition	34	(270)
Cash used by changes in other working capital, net of acquisition	(265)	(238)
Net Cash Provided by Operating Activities	605	722
Cash Flows from Investing Activities		
Acquisition of businesses, net of cash acquired	(141)	(345)
Capital expenditures	(330)	(374)
Increase in restricted cash, net	(11)	(3)
Decrease/(increase) in notes receivable	15	(11)
Purchases of emission allowances	(45)	(52)
Proceeds from sale of emission allowances	11	15
Investments in nuclear decommissioning trust fund securities	(76)	(172)
Proceeds from sales of nuclear decommissioning trust fund securities	67	157
Proceeds from renewable energy grants	102	
Proceeds from sale of assets, net	30	6
Proceeds from sale of equity method investment		284
Other	(7)	(5)
Net Cash Used by Investing Activities	(385)	(500)
Cash Flows from Financing Activities		
Payment of dividends to preferred stockholders	(5)	(21)
Payment for treasury stock	(50)	

Net receipt from/(payments for) acquired derivatives that include financing elements	27	(22)
Installment proceeds from sale of noncontrolling interest in subsidiary	50	50
Proceeds from issuance of long-term debt	141	820
Proceeds from issuance of term loan for funded letter of credit facility	1,300	
Increase in restricted cash supporting funded letter of credit facility	(1,300)	
Proceeds from issuance of common stock	2	
Payment of deferred debt issuance costs	(53)	(29)
Payments for short and long-term debt	(459)	(233)
Net Cash (Used)/Provided by Financing Activities	(347)	565
Effect of exchange rate changes on cash and cash equivalents	(9)	1
Net (Decrease)/Increase in Cash and Cash Equivalents	(136)	788
Cash and Cash Equivalents at Beginning of Period	2,304	1,494
Cash and Cash Equivalents at End of Period	$ 2,168	$ 2,282

See notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1 Basis of Presentation

NRG Energy, Inc., or NRG or the Company, is primarily a wholesale power generation company with a significant presence in major competitive power markets in the United States, as well as a major retail electricity provider in the ERCOT (Texas) market. NRG is engaged in the ownership, development, construction and operation of power generation facilities, both conventional and renewable, the transacting in and trading of fuel and transportation services, the trading of energy, capacity and related products in the United States and select international markets, and supply of electricity and energy services to retail electricity customers in the Texas market. The Company also seeks to invest in and deploy new energy technologies.

The accompanying unaudited interim condensed consolidated financial statements have been prepared in accordance with the SEC s regulations for interim financial information and with the instructions to Form 10-Q. Accordingly, they do not include all of the information and notes required by generally accepted accounting principles for complete financial statements. The following notes should be read in conjunction with the accounting policies and other disclosures as set forth in the notes to the Company s financial statements in its Annual Report on Form 10-K for the year ended December 31, 2009. Interim results are not necessarily indicative of results for a full year.

In the opinion of management, the accompanying unaudited interim condensed consolidated financial statements contain all material adjustments consisting of normal and recurring accruals necessary to present fairly the Company s consolidated financial position as of June 30, 2010, the results of operations for the three and six months ended June 30, 2010, and 2009, and cash flows for the six months ended June 30, 2010 and 2009. Certain prior-year amounts have been reclassified for comparative purposes.

Use of Estimates

The preparation of consolidated financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions. These estimates and assumptions impact the reported amount of assets and liabilities and disclosures of contingent assets and liabilities as of the date of the consolidated financial statements. They also impact the reported amount of net earnings during the reporting period. Actual results could be different from these estimates.

Note 2 Summary of Significant Accounting Policies

Other Cash Flow Information

NRG s investing activities do not include non-cash capital expenditures of $113 million which were accrued at June 30, 2010.

Recent Accounting Developments

ASU No. 2009-17 On January 1, 2010, the Company adopted the provisions of ASU No. 2009-17, *Consolidations: Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities*, or ASU 2009-17. This guidance amends ASC 810 by altering how a company determines when an entity that is insufficiently capitalized or not controlled through its voting interests should be consolidated. The previous ASC 810 guidance required a quantitative analysis of the economic risk/rewards of a Variable Interest Entity, or a VIE, to determine the primary beneficiary. ASU 2009-17 specifies that a qualitative analysis be performed, requiring the primary beneficiary to have both the power to direct the activities of a VIE that most significantly impact the entities economic performance, as well as either the obligation to absorb losses or the right to receive benefits that could potentially be significant to the VIE. The Company s adoption of ASU 2009-17 on January 1, 2010, did not have an impact on its results of operations, financial position or cash flows.

ASU No. 2010-10 In February 2010, the FASB issued ASU No. 2010-10, *Consolidation (Topic 810): Amendments for Certain Investment Funds*, or ASU 2010-10. The amendments to ASC 810 clarify that related parties should be considered when evaluating the criteria for determining whether a decision maker s or service provider s fee represents a variable interest. In addition, the amendments clarify that a quantitative calculation should not be the sole basis for evaluating whether a decision maker s or service provider s fee represents a variable interest. The Company adopted the provisions of ASU 2010-10 effective January 1, 2010, with no impact on its results of operations, financial position or cash flows.

Other effects of ASU 2009-17/ASU 2010-10 adoption NRG determined that one of its equity method investments was a VIE as of January 1, 2010, upon adoption of this new guidance. NRG owns a 50% interest in Sherbino I Wind Farm LLC, or Sherbino, a 150MW wind farm operated as a joint venture with BP Wind Energy North America Inc., or BP Wind. The Company has determined that Sherbino is a VIE, but the Company is not the primary beneficiary, under the amended guidance in ASU 2009-17 and ASU 2010-10. Therefore, NRG will continue to account for its investment in Sherbino under the equity method. NRG s maximum exposure to loss is limited to its equity investment, which is $94 million as of June 30, 2010.

Borrowings of an equity method investment In December 2008, Sherbino entered into a 15-year term loan facility which is non-recourse to NRG. As of June 30, 2010, the outstanding principal balance of the term loan facility was $131 million, and is secured by substantially all of Sherbino s assets and membership interests.

ASU No. 2010-09 In February 2010, the FASB issued ASU No. 2010-09, *Subsequent Events (Topic 855): Amendments to Certain Recognition and Disclosure Requirements*, or ASU 2010-09. Under the amendments of ASU 2010-09, an entity that is an SEC filer is not required to disclose the date through which subsequent events have been evaluated. As this guidance provides only disclosure requirements, the adoption of ASU 2010-09 effective January 1, 2010, did not impact the Company s results of operations, financial position or cash flows.

Other The following accounting standards were adopted on January 1, 2010, with no impact on the Company s results of operations, financial position or cash flows:

- ASU No. 2009-15, *Accounting for Own-Share Lending Arrangements in Contemplation of Convertible Debt Issuance or Other Financing*, or ASU 2009-15.
- ASU No. 2010-02, *Consolidation (Topic 810): Accounting and Reporting for Decreases in Ownership of a Subsidiary a Scope Clarification,* or ASU 2010-02.
- ASU No. 2010-06, *Fair Value Measurement and Disclosures: Improving Disclosures about Fair Value Measurements*, or ASU 2010-06.

Note 3 Comprehensive Income/(Loss)

The following table summarizes the components of the Company s comprehensive income/(loss), net of tax:

	Three months ended June 30,		**Six months ended June 30,**	
(In millions)	**2010**	**2009**	**2010**	**2009**
Net income attributable to NRG Energy, Inc.	$ 211	$ 433	$269	$631
Changes in derivative activity	(154)	(109)	103	64
Foreign currency translation adjustment	(36)	36	(42)	18
Reclassification adjustment for translation gain realized upon sale of foreign investments		(22)		(22)
Unrealized (loss)/gain on available-for-sale securities	(1)	1	(1)	2
Other comprehensive (loss)/income	(191)	(94)	60	62
Comprehensive income attributable to NRG Energy, Inc.	$ 20	$ 339	$329	$693

The following table summarizes the changes in the Company s accumulated other comprehensive income, net of tax:

(In millions)	
Accumulated other comprehensive income as of December 31, 2009	$416

Changes in derivative activity	103
Foreign currency translation adjustment	(42)
Unrealized loss on available-for-sale securities	(1)
Accumulated other comprehensive income as of June 30, 2010	$476

Note 4 Business Acquisitions and Dispositions

Acquisition of Reliant Energy

On May 1, 2009, NRG, through its wholly-owned subsidiary, NRG Retail LLC, acquired Reliant Energy from RRI Energy, Inc., or RRI, which consisted of the entire Texas electric retail business operations of RRI, including the exclusive use of the trade name Reliant and related branding rights. The acquisition of Reliant Energy was accounted for under the acquisition method of accounting in accordance with ASC 805. Accordingly, NRG conducted an assessment of net assets acquired and recognized identifiable assets acquired and liabilities assumed at their acquisition date fair values. The accounting for this business combination was completed on March 31, 2010.

NRG paid RRI total cash consideration of approximately $370 million. NRG also recognized a $31 million non-cash gain at the acquisition date, on the settlement of a pre-existing relationship, representing the in-the-money value to NRG of an agreement that permits Reliant Energy to call on certain NRG gas plants when necessary for Reliant Energy to meet its load obligations. This non-cash gain was considered a component of consideration in accordance with ASC 805, and together with cash consideration, brings total consideration to approximately $401 million.

The following table summarizes the values assigned to the net assets acquired, including cash acquired of $6 million, as of the acquisition date:

	(In millions)
Assets	
Current and non-current assets	$ 635
Property, plant and equipment	72
Intangible assets subject to amortization:	
In-market customer contracts	790
Customer relationships	405
Trade names	178
In-market energy supply contracts	54
Other	6
Derivative assets	1,942
Deferred tax asset, net	14
Goodwill	
Total assets acquired	$ 4,096
Liabilities	
Current and non-current liabilities	$ 556
Derivative liabilities	2,996
Out-of-market energy supply and customer contracts	143
Total liabilities assumed	$ 3,695
Net assets acquired	$ 401

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Measurement period adjustments

The following measurement period adjustments to the provisional amounts, attributable to refinement of the underlying appraisal assumptions, were recognized during 2009 subsequent to the acquisition date and through the first quarter of 2010, the end of the measurement period:

	Increase/(Decrease) (In millions)
Assets	
Intangible assets subject to amortization:	
In-market customer contracts	$ 57
Customer relationships	(76)
In-market energy supply contracts	17
Deferred tax asset, net	3
Total assets acquired	1
Liabilities	
Current and non-current liabilities	6
Out-of-market energy supply and customer contracts	(5)
Total liabilities assumed	1
Net assets acquired	$

Other Acquisitions

Northwind Phoenix On June 22, 2010, NRG, through its wholly-owned subsidiary, NRG Thermal LLC, or NRG Thermal, acquired Northwind Phoenix, LLC, or Northwind Phoenix, for a total purchase price of $100 million, plus a payment for acquired working capital true-ups. Northwind Phoenix owns and operates a district cooling system that provides chilled water to commercial buildings in the Phoenix central business district. In addition, Northwind Phoenix maintains and operates Combined Heat and Power, or CHP, plants that provide chilled water, steam and electricity in metropolitan Tucson and to portions of Arizona State University campuses in Tempe and Mesa. The acquisition was financed by the issuance of $100 million in notes by NRG Thermal. See Note 8, *Long-Term Debt,* for information related to the notes issued.

South Trent On June 14, 2010, NRG acquired South Trent Wind LLC, owner of the South Trent wind farm, or South Trent, a 101 MW wind farm near Sweetwater, Texas, for a total purchase price of $111 million. South Trent commenced operations in January 2009 and consists of 44 turbines producing up to 2.3 MW of power each. The project has a 20-year PPA, which commenced January 2009, for all generation from the site. In connection with the acquisition, NRG paid $32 million in cash and South Trent entered into a financing arrangement that includes a $79 million term loan. See Note 8, *Long-Term Debt*, for information related to this financing arrangement.

Dispositions

Padoma On January 11, 2010, NRG sold its terrestrial wind development company, Padoma Wind Power LLC, or Padoma, to Enel North America, Inc., or Enel. NRG retained its existing ownership interest in its three Texas wind farms: Sherbino, Elbow Creek and Langford. In addition, NRG will maintain a strategic partnership with Enel to evaluate potential opportunities in renewable energy, including the opportunity to participate in wind projects currently in development. NRG recognized a gain on the sale of Padoma of $23 million, which was recorded as a component of operating income in the statement of operations.

MIBRAG On June 10, 2009, NRG sold its 50% ownership interest in Mibrag B.V. whose principal holding was MIBRAG. For its share, NRG received EUR 203 million ($284 million at an exchange rate of 1.40 U.S.$/EUR), net of transaction costs. During the three and six months ended June 30, 2009, NRG recognized an after-tax gain of

$128 million. Prior to completion of the sale, NRG continued to record its share of MIBRAG s operations to Equity in earnings of unconsolidated affiliates. In connection with the transaction, NRG entered into a foreign currency forward contract to hedge the impact of exchange rate fluctuations on the sale proceeds. For the three and six months ended June 30, 2009, NRG recorded an exchange loss of $15 million and $24 million, respectively, on the contract within Other income/(expense), net.

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Note 5 Fair Value of Financial Instruments

The estimated carrying values and fair values of NRG s recorded financial instruments are as follows:

	Carrying Amount		Fair Value	
	June 30, 2010	December 31, 2009	June 30, 2010	December 31, 2009
	(In millions)			
Assets:				
Cash and cash equivalents	$2,168	$2,304	$2,168	$ 2,304
Funds deposited by counterparties	310	177	310	177
Restricted cash	13	2	13	2
Cash collateral paid in support of energy risk management activities	391	361	391	361
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	10	9	10	9
Marketable equity securities	3	5	3	5
Trust fund investments	362	369	362	369
Notes receivable	221	231	232	238
Derivative assets	2,710	2,319	2,710	2,319
Restricted cash supporting funded letter of credit facility	1,300		1,300	
Liabilities:				
Long-term debt, including current portion	8,069	8,295	7,991	8,211
Funded letter of credit	1,300		1,250	
Cash collateral received in support of energy risk management activities	310	177	310	177
Derivative liabilities	$1,917	$1,860	$1,917	$ 1,860

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Recurring Fair Value Measurements

The following table presents assets and liabilities measured and recorded at fair value on the Company s condensed consolidated balance sheet on a recurring basis and their level within the fair value hierarchy:

(In millions)	**Fair Value**			
As of June 30, 2010	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	$2,168	$	$	$2,168
Funds deposited by counterparties	310			310
Restricted cash	13			13
Cash collateral paid in support of energy risk management activities	391			391
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities			10	10
Marketable equity securities	3			3
Trust fund investments				
Cash and cash equivalents	9			9
U.S. government and federal agency obligations	27			27
Federal agency mortgage-backed securities		61		61
Commercial mortgage-backed securities		10		10
Corporate debt securities		50		50
Marketable equity securities	172		32	204
Foreign government fixed income securities		1		1
Derivative assets				
Commodity contracts	629	2,005	65	2,699
Interest rate contracts			11	11
Restricted cash supporting funded letter of credit facility	1,300			1,300
Total assets	$5,022	$2,127	$118	$7,267
Cash collateral received in support of energy risk management activities	$ 310	$	$	$ 310
Derivative liabilities				
Commodity contracts	681	967	152	1,800
Interest rate contracts		117		117
Total liabilities	$ 991	$1,084	$152	$2,227

(In millions)	**Fair Value**			
As of December 31, 2009	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	$2,304	$	$	$2,304
Funds deposited by counterparties	177			177
Restricted cash	2			2
Cash collateral paid in support of energy risk management activities	361			361
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities			9	9

Marketable equity securities	5			5
Trust fund investments	214	118	37	369
Derivative assets	489	1,767	63	2,319
Total assets	$3,552	$1,885	$109	$5,546
Cash collateral received in support of energy risk management activities	$ 177	$	$	$ 177
Derivative liabilities	501	1,283	76	1,860
Total liabilities	$ 678	$1,283	$ 76	$2,037

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There have been no transfers during the three months and six months ended June 30, 2010, between Levels 1 and 2. The following table reconciles the beginning and ending balances for financial instruments that are recognized at fair value in the consolidated financial statements using significant unobservable inputs:

	Three months ended June 30, 2010				Six months ended June 30, 2010			
(In millions)	**Debt Securities**	**Trust Fund Investments**	**Derivatives[(a)]**	**Total**	**Debt Securities**	**Trust Fund Investments**	**Derivatives[(a)]**	**Total**
Beginning Balance	$ 9	$ 37	$ (25)	$ 21	$ 9	$ 37	$ (13)	$ 33
Total gains/(losses) (realized and unrealized)								
Included in earnings			(63)	(63)			(31)	(31)
Included in OCI	1			1	1			1
Included in nuclear decommissioning obligations		(5)		(5)		(5)		(5)
Purchases			8	8			9	9
Transfer into Level 3 [(b)]			15	15			(47)	(47)
Transfer out of Level 3 [(b)]			(11)	(11)			6	6
Ending balance as of June 30, 2010	$10	$ 32	$ (76)	$(34)	$10	$ 32	$ (76)	$(34)
The amount of the total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held as of June 30, 2010	$	$	$ (61)	$(61)	$	$	$ (36)	$(36)

	Three months ended June 30, 2009				Six months ended June 30, 2009			
(In millions)	**Debt Securities**	**Trust Fund Investments**	**Derivatives[(a)]**	**Total**	**Debt Securities**	**Trust Fund Investments**	**Derivatives[(a)]**	**Total**
Beginning Balance	$7	$ 27	$ 126	$160	$7	$ 31	$ 49	$ 87
Total gains/(losses) (realized and unrealized)								
Included in earnings			(49)	(49)			(30)	(30)
Included in nuclear decommissioning obligations		6		6		2		2
Purchases/(sales), net		1	(8)	(7)		1	(4)	(3)
Transfer in/(out) of Level 3 [(b)]			(19)	(19)			35	35

Ending balance as of June 30, 2009	$7	$ 34	$ 50	$ 91	$7	$ 34	$ 50	$ 91
The amount of the total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held as of June 30, 2009	$	$	$ (1)	$ (1)	$	$	$ 28	$ 28

(a) *Consists of derivative assets and liabilities, net.*

(b) *Transfers in/(out) of Level 3 are related to the availability of external broker quotes. All transfers out are to Level 2.*

Realized and unrealized gains and losses included in earnings that are related to the energy derivatives are recorded in operating revenues and cost of operations.

In determining the fair value of NRG s Level 2 and 3 derivative contracts, NRG applies a credit reserve to reflect credit risk which is calculated based on credit default swaps. As of June 30, 2010, the credit reserve resulted in an $11 million decrease in fair value which is composed of a $6 million loss in OCI and a $5 million loss in operating revenue and cost of operations.

Concentration of Credit Risk

In addition to the credit risk discussion as disclosed in Note 2, *Summary of Significant Accounting Policies*, to the Company s financial statements in its Annual Report on Form 10-K for the year ended December 31, 2009, the following item is a discussion of the concentration of credit risk for the Company s financial instruments. Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. NRG is exposed to counterparty credit risk through various activities including wholesale sales, fuel purchases and retail supply and retail customer credit risk through its retail load activities.

Counterparty Credit Risk

The Company monitors and manages counterparty credit risk through credit policies that include: (i) an established credit approval process; (ii) a daily monitoring of counterparties credit limits; (iii) the use of credit mitigation measures such as margin, collateral, prepayment arrangements, or volumetric limits; (iv) the use of payment netting agreements; and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. The Company seeks to mitigate counterparty credit risk with a diversified portfolio of counterparties. The Company also has credit protection within various agreements to call on additional collateral support if and when necessary. Cash margin is collected and held at NRG to cover the credit risk of the counterparty until positions settle.

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As of June 30, 2010, total counterparty credit exposure to substantially all counterparties was $1.5 billion and NRG held cash collateral against those positions of $310 million and letters of credit of $11 million, resulting in a net exposure of $1.2 billion. Total counterparty credit exposure is discounted at the risk free rate.

The following table highlights the counterparty credit quality and the net counterparty credit exposure by industry sector. Net counterparty credit exposure is defined as the aggregate net asset position for NRG with counterparties where netting is permitted under the enabling agreement and includes all cash flow, mark-to-market and Normal Purchase Normal Sale, or NPNS, and non-derivative transactions. The exposure is shown net of collateral held, and includes amounts net of receivables or payables.

Category	**Net Exposure[(a)] (% of Total)**
Financial institutions	59%
Utilities, energy, merchants, marketers and other	31
Coal suppliers	4
ISOs	6
Total as of June 30, 2010	100%

Category	**Net Exposure[(a)] (% of Total)**
Investment grade	88%
Non-Investment grade	2
Non-rated	10
Total as of June 30, 2010	100%

(a) Counterparty credit exposure excludes California tolling, Northeast load obligations, certain cooperative load contracts, and Texas Westmoreland coal contracts. The aforementioned exposures were excluded for various reasons

including regulatory support or liens held against the contracts which serve to reduce the risk of loss. NRG also excludes uranium and coal transportation contracts from counterparty credit exposure because of the illiquidity of the reference markets. Credit exposure also excludes any exposure NRG has to counterparties of non-recourse subsidiaries.

NRG has counterparty credit risk exposure to certain counterparties representing more than 10% of total net exposure and the aggregate of such counterparties was $409 million. Approximately 89% of NRG s positions relating to credit risk roll-off by the end of 2012. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration. Given the credit quality, diversification and term of the exposure in the portfolio, NRG does not anticipate a material impact on the Company s financial results or results of operations from nonperformance by any of NRG s counterparties.

Retail Customer Credit Risk

NRG is exposed to retail credit risk through the Company s competitive electricity supply business, which serves C&I customers and the Mass market in Texas. Retail credit risk results when a customer fails to pay for services rendered. The losses could be incurred from nonpayment of customer accounts receivable and any in-the-money forward value. NRG manages retail credit risk through the use of established credit policies that include monitoring of the portfolio, and the use of credit mitigation measures such as deposits or prepayment arrangements.

As of June 30, 2010, the Company s retail customer credit exposure to C&I customers was diversified across many customers and various industries, with a significant portion of the exposure with government entities.

NRG is also exposed to retail customer credit risk relating to its Mass customers, which may result in a write-off of bad debt. During 2010, the Company continued to experience improved customer payment behavior, but current economic conditions may affect the Company s customers ability to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in bad debt expense.

This footnote should be read in conjunction with the complete description under Note 5, *Fair Value of Financial Instruments*, to the Company s financial statements in its Annual Report on Form 10-K for the year ended December 31, 2009.

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Note 6 Nuclear Decommissioning Trust Fund

NRG s nuclear decommissioning trust fund assets, which are for its portion of the decommissioning of the South Texas Project, or STP, are comprised of securities classified as available-for-sale and recorded at fair value based on actively quoted market prices. NRG accounts for the nuclear decommissioning trust fund in accordance with ASC-980 *Regulated Operations*, or ASC 980. Since the Company is in compliance with the Public Utility Commission of Texas, or PUCT rules and regulations regarding decommissioning trusts and the cost of decommissioning is the responsibility of the Texas ratepayers, not NRG, all realized and unrealized gains or losses (including other than-temporary-impairments) related to the Nuclear Decommissioning Trust Fund are recorded to the Nuclear Decommissioning Trust Liability to the ratepayers and are not included in net income or accumulated other comprehensive income, consistent with regulatory treatment.

The following table summarizes the aggregate fair values and unrealized gains and losses (including other-than-temporary impairments) for the securities held in the trust funds as of June 30, 2010, and December 31, 2009, as well as information about the contractual maturities of those securities. The cost of securities sold is determined on the specific identification method.

	As of June 30, 2010				As of December 31, 2009			
(In millions, except otherwise noted)	**Fair Value**	**Unrealized gains**	**Unrealized losses**	**Weighted-average maturities (in years)**	**Fair Value**	**Unrealized gains**	**Unrealized losses**	**Weighted-average maturities (in years)**
Cash and cash equivalents	$ 9	$	$		$ 4	$	$	
U.S. government and federal agency obligations	25	2		11	23	1		8
Federal agency mortgage-backed securities	61	3		22	60	2		23
Commercial mortgage-backed securities	10		1	30	10		1	29
Corporate debt securities	50	3		10	48	3	1	10
Marketable equity securities	204	73	3		220	89	2	
Foreign government fixed income securities	1			7	2			6
Total	$360	$ 81	$ 4		$367	$ 95	$ 4	

The following tables summarize proceeds from sales of available-for-sale securities and the related realized gains and losses from these sales.

	Six months ended June 30,	
(In millions)	**2010**	**2009**
Realized gains	$ 2	$ 2
Realized losses	2	5
Proceeds from sale of securities	67	157

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Note 7 Accounting for Derivative Instruments and Hedging Activities

ASC 815 requires NRG to recognize all derivative instruments on the balance sheet as either assets or liabilities and to measure them at fair value each reporting period unless they qualify for a NPNS exception. If certain conditions are met, NRG may be able to designate certain derivatives as cash flow hedges and defer the effective portion of the change in fair value of the derivatives to accumulated OCI, until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge is immediately recognized in earnings.

For derivatives designated as hedges of the fair value of assets or liabilities, the changes in fair value of both the derivative and the hedged transaction are recorded in current earnings.

For derivatives that are not designated as cash flow hedges or do not qualify for hedge accounting treatment, the changes in the fair value will be immediately recognized in earnings. Under the guidelines established per ASC 815, certain derivative instruments may qualify for the NPNS exception and are therefore exempt from fair value accounting treatment. ASC 815 applies to NRG s energy related commodity contracts, interest rate swaps, and foreign exchange contracts.

As the Company engages principally in the trading and marketing of its generation assets and retail business, some of NRG s commercial activities qualify for hedge accounting under the requirements of ASC 815. In order for the generation assets to qualify, the physical generation and sale of electricity should be highly probable at inception of the trade and throughout the period it is held, as is the case with the Company s baseload plants. For this reason, many trades in support of NRG s baseload units normally qualify for NPNS or cash flow hedge accounting treatment, and trades in support of NRG s peaking unit s asset optimization will generally not qualify for hedge accounting treatment, with any changes in fair value likely to be reflected on a mark-to-market basis in the statement of operations. Most of the retail load contracts either qualify for the NPNS exception or fail to meet the criteria for a derivative and the majority of the supply contracts are recorded under mark-to-market accounting. All of NRG s hedging and trading activities are subject to limits within the Company s Risk Management Policy.

Energy-Related Commodities

To manage the commodity price risk associated with the Company s competitive supply activities and the price risk associated with wholesale and retail power sales from the Company s electric generation facilities, NRG may enter into a variety of derivative and non-derivative hedging instruments, utilizing the following:

- Forward contracts, which commit NRG to sell or purchase energy commodities or purchase fuels in the future.
- Futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument.
- Swap agreements, which require payments to or from counter-parties based upon the differential between two prices for a predetermined contractual, or notional, quantity.
- Option contracts, which convey the right or obligation to purchase or sell a commodity.
- Weather and hurricane derivative products used to mitigate a portion of Reliant Energy s lost revenue due to weather.

The objectives for entering into derivative contracts designated as hedges include:

- Fixing the price for a portion of anticipated future electricity sales through the use of various derivative instruments including gas collars and swaps at a level that provides an acceptable return on the Company s electric generation operations.
- Fixing the price of a portion of anticipated fuel purchases for the operation of NRG s power plants.

As of June 30, 2010, NRG had cash flow hedge energy-related derivative financial instruments extending through December 2013.

NRG s trading activities are subject to limits within the Company s Risk Management Policy. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings.

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Interest Rate Swaps

NRG is exposed to changes in interest rates through the Company s issuance of variable and fixed rate debt. In order to manage the Company s interest rate risk, NRG enters into interest rate swap agreements. As of June 30, 2010, NRG had interest rate derivative instruments extending through June 2028, the majority of which had been designated as either cash flow or fair value hedges.

Volumetric Underlying Derivative Transactions

The following table summarizes the net notional volume buy/(sell) of NRG s open derivative transactions broken out by commodity, excluding those derivatives that qualified for the NPNS exception as of June 30, 2010, and December 31, 2009. Option contracts are reflected using delta volume. Delta volume equals the notional volume of an option adjusted for the probability that the option will be in-the-money at its expiration date.

		Total Volume	
		June 30, 2010	**December 31, 2009**
Commodity	**Units**	**(In millions)**	
Emissions	Short Ton	(7)	(2)
Coal	Short Ton	42	55
Natural Gas	MMBtu	(299)	(484)
Oil	Barrel		1
Power	MWh	11	5
Capacity	MW/Day	(3)	(2)
Interest	Dollars	$3,203	$ 3,291

Fair Value of Derivative Instruments

The Company has elected to disclose derivative assets and liabilities on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. Also, collateral received or paid on the Company s derivative assets or liabilities are recorded on a separate line item on the balance sheet. The Company has chosen not to offset positions as permitted in ASC 815. As of June 30, 2010, the Company recorded $391 million of cash collateral paid and $310 million of cash collateral received on its balance sheet.

The following table summarizes the fair value within the derivative instrument valuation on the balance sheet as of June 30, 2010, and December 31, 2009:

	Fair Value			
	Derivative Assets		**Derivative Liabilities**	
(In millions)	**June 30, 2010**	**December 31, 2009**	**June 30, 2010**	**December 31, 2009**
Derivatives Designated as Cash Flow or Fair Value Hedges:				
Interest rate contracts current	$	$	$ 48	$ 2
Interest rate contracts long-term	11	8	69	106
Commodity contracts current	370	300	8	12
Commodity contracts long-term	511	508	1	6
Total Derivatives Designated as Cash Flow or Fair Value Hedges	892	816	126	126

Derivatives Not Designated as Cash Flow or Fair Value Hedges:				
Commodity contracts current	1,430	1,336	1,428	1,459
Commodity contracts long-term	388	167	363	275
Total Derivatives Not Designated as Cash Flow or Fair Value Hedges	1,818	1,503	1,791	1,734
Total Derivatives	$2,710	$ 2,319	$1,917	$ 1,860

Accumulated Other Comprehensive Income

The following table summarizes the effects of ASC 815 on NRG s Accumulated OCI balance attributable to cash flow hedge derivatives, net of tax:

	Three months ended June 30, 2010			Six months ended June 30, 2010		
(In millions)	**Energy Commodities**	**Interest Rate**	**Total**	**Energy Commodities**	**Interest Rate**	**Total**
Beginning Balance	$ 719	$(56)	$ 663	$ 461	$(55)	$ 406
Reclassified from Accumulated OCI to income:						
- Due to realization of previously deferred amounts	(128)	(2)	(130)	(234)		(234)
Mark-to-market of cash flow hedge accounting contracts	(16)	(8)	(24)	348	(11)	337
Accumulated OCI balance at June 30, 2010, net of $308 tax	$ 575	$(66)	$ 509	$ 575	$(66)	$ 509
Gains/(losses) expected to be realized from OCI during the next 12 months, net of $186 tax	$ 348	$(32)	$ 316	$ 348	$(32)	$ 316
(Losses)/gains recognized in income from the ineffective portion of cash flow hedges	$ (12)	$ 2	$ (10)	$ (14)	$ 2	$ (12)

	Three months ended June 30, 2009			Six months ended June 30, 2009		
(In millions)	**Energy Commodities**	**Interest Rate**	**Total**	**Energy Commodities**	**Interest Rate**	**Total**
Beginning Balance	$567	$(79)	$488	$ 406	$(91)	$ 315
Reclassified from Accumulated OCI to income:						
- Due to realization of previously deferred amounts	(76)	(1)	(77)	(188)		(188)
- Due to discontinuation of cash flow hedge accounting				(135)		(135)
Mark-to-market of cash flow hedge accounting contracts	(46)	14	(32)	362	25	387
Accumulated OCI balance at June 30, 2009, net of $233	$445	$(66)	$379	$ 445	$(66)	$ 379

tax						
(Losses)/gains recognized in income from the ineffective portion of cash flow hedges	$ (3)	$	$ (3)	$ 1	$	$ 1

Amounts reclassified from Accumulated OCI into income and amounts recognized in income from the ineffective portion of cash flow hedges are recorded to operating revenue for commodity contracts and interest expense for interest rate contracts.

Accounting guidelines require a high degree of correlation between the derivative and the hedged item throughout the period in order to qualify as a cash flow hedge. As of July 31, 2008, the Company s regression analysis for natural gas prices to ERCOT power prices, while positively correlated, did not meet the required threshold for cash flow hedge accounting for calendar years 2012 and 2013. As a result, the Company de-designated its 2012 and 2013 ERCOT cash flow hedges as of July 31, 2008, and prospectively marked these derivatives to market. On April 1, 2009, the required correlation threshold for cash flow hedge accounting was achieved for these transactions, and accordingly, these hedges were re-designated as cash flow hedges.

As discussed in Note 3, *Business Acquisitions*, to the Company s financial statements in its Annual Report on Form 10-K for the year ended December 31, 2009, on October 5, 2009, the Company amended the CSRA with Merrill Lynch. In connection with the CSRA Amendment, NRG net settled certain in-the-money transactions with Morgan Stanley. As these transactions were net settled, $245 million in OCI was frozen and is recognized into income as the underlying power from the baseload plants is generated.

The following table summarizes the amount of gain/(loss) resulting from fair value hedges reflected in interest income/(expense) for interest rate contracts:

	Three months ended June 30,		**Six months ended June 30,**	
(In millions)	**2010**	**2009**	**2010**	**2009**
Derivative	$	$ (7)	$ 3	$ (8)
Senior Notes (hedged item)	$	$ 7	$ (3)	$ 8

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Impact of Derivative Instruments on the Statement of Operations

In accordance with ASC 815, unrealized gains and losses associated with changes in the fair value of derivative instruments not accounted for as cash flow hedge derivatives and ineffectiveness of hedge derivatives are reflected in current period earnings.

The following table summarizes the pre-tax effects of economic hedges that did not qualify for cash flow hedge accounting, ineffectiveness on cash flow hedges, and trading activity on NRG s statement of operations. These amounts are included within operating revenues and cost of operations.

(In millions)	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Unrealized mark-to-market results				
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	$ (51)	$ (18)	$ (91)	$ (34)
Reversal of loss positions acquired as part of the Reliant Energy acquisition as of May 1, 2009	60	210	150	210
Reversal of previously recognized unrealized losses/(gains) on settled positions related to trading activity	8	(35)	26	(104)
Net unrealized gains/(losses) on open positions related to economic hedges	48	(40)	(70)	309
(Losses)/gains on ineffectiveness associated with open positions treated as cash flow hedges	(12)	(3)	(14)	1
Net unrealized gains on open positions related to trading activity	9	1	23	8
Total unrealized gains	$ 62	$ 115	$ 24	$ 390

(In millions)	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Revenue from operations energy commodities	$ (83)	$ (210)	$ (14)	$ 117
Cost of operations	145	325	38	273
Total impact to statement of operations	$ 62	$ 115	$ 24	$ 390

Reliant Energy s loss positions were acquired as of May 1, 2009, and valued using forward prices on that date. The roll-off amounts were offset by realized losses at the settled prices and are reflected in the cost of operations during the same period.

For the six months ended June 30, 2010, the $70 million loss from economic hedge positions is the result of a decrease in value of forward purchases and sales of natural gas, electricity and fuel due to a decrease in forward power and gas prices.

For the six months ended June 30, 2009, the $309 million gain from economic hedge positions includes $217 million recognized in earnings from previously deferred amounts in Accumulated OCI as the Company discontinued cash flow hedge accounting for certain 2009 transactions in Texas and New York due to lower expected generation, and $92 million of increase in value of forward purchases and sales of electricity and fuel due to a decrease in forward power and gas prices.

Discontinued Normal Purchase and Sale for Coal Purchases Due to lower coal-fired generation during the first quarter 2009, the Company s coal consumption was lower than forecasted. The Company net settled some of its coal purchases under NPNS designation and thus was not able to assert physical delivery under these coal contracts. The forward positions previously treated as accrual accounting were reclassified into mark-to-market accounting during the first quarter of 2009 and prospectively. The impact of discontinuance of coal NPNS designated transactions resulted in a derivative loss of $29 million that was reflected in the cost of operations for the six months ended June 30, 2009.

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Credit Risk Related Contingent Features

Certain of the Company s hedging agreements contain provisions that require the Company to post additional collateral if the counterparty determines that there has been deterioration in credit quality, generally termed adequate assurance under the agreements, or require the Company to post additional collateral if there was a one notch downgrade in the Company s credit rating. The collateral required for contracts that have adequate assurance clauses that are in a net liability position as of June 30, 2010, was $63 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of June 30, 2010, was $11 million. The Company is also a party to certain marginable agreements where NRG has a net liability position but the counterparty has not called for the collateral due, which is approximately $15 million as of June 30, 2010.

See Note 5, *Fair Value of Financial Instruments*, to this Form 10-Q for discussion regarding concentration of credit risk.

Note 8 Long-Term Debt

In March 2010, NRG made a repayment of approximately $229 million to its first lien lenders under the Term Loan Facility. This payment resulted from the mandatory annual offer of a portion of NRG s excess cash flow (as defined in the Senior Credit Facility) for the prior year.

Amendment and Extension of Maturity Dates

On June 30, 2010, NRG completed an amendment and extension of the Senior Credit Facility, resulting in the following:

NRG extended the maturity date for approximately $1.0 billion of its $2.0 billion outstanding Term Loan Facility to August 31, 2015, with the remaining amount due on the original maturity date of February 1, 2013. The interest rate for the extended portion of the facility increased from LIBOR+1.75% to LIBOR+3.25%;

Borrowing capacity under the Revolving Credit Facility was reduced from $1.0 billion to $875 million and its maturity was extended to August 31, 2015. The interest rate for the amended Revolving Credit Facility is LIBOR+3.25%;

The existing Synthetic Letter of Credit Facility was converted into a term loan-backed funded letter of credit facility, or Funded Letter of Credit Facility, with the term loan reflected as a non-current liability and the proceeds of the term loan reflected as non-current restricted cash on NRG s balance sheet. Of the total $1.3 billion borrowed under the term loan, $500 million will mature on February 1, 2013 and bear interest at LIBOR+1.75%, while $800 million will mature August 31, 2015 and bear interest at LIBOR+3.25%.

Restricted cash supporting funded letter of credit Pursuant to the letter of credit reimbursement agreements entered into as of June 30, 2010, or the LC Agreements, and the Senior Credit Facility, as amended, NRG made capital contributions to NRG LC Facility Company, or LCFC, a separate, bankruptcy-remote entity that is a wholly-owned subsidiary of NRG. In addition, pursuant to reimbursement agreements related to the LC Agreements, NRG or its subsidiaries is liable for certain reimbursement obligations to LCFC. As of June 30, 2010, LCFC has cash invested in short-term certificates of deposit with an aggregate market value of $1.3 billion. Pursuant to the LC Agreements, which have a maximum committed amount of $1.3 billion, LCFC is liable on various letters of credit issued by Deutsche Bank AG, New York Branch and Citibank, N.A. These letters of credit will be used to support the businesses of NRG and certain of its other subsidiaries and equity investments. LCFC has secured its reimbursement and other obligations under the LC Agreements with a pledge of the cash and cash equivalents that it owns. The LC Agreements require LCFC s assets to be used first and foremost to satisfy claims of creditors of LCFC. Although the cash and cash equivalents held by LCFC are included in the consolidated assets of NRG, such cash and cash equivalents are not available to creditors of NRG.

Expenses of approximately $45 million, including fees to the lenders and other fees, were deferred and will be expensed in part over the original term of maturity through 2013 and in part over the amended maturity through 2015.

As of June 30, 2010, NRG had issued $820 million of letters of credit under the Funded Letter of Credit Facility, leaving $480 million available for future issuances. Under the Revolving Credit Facility as of June 30, 2010, NRG had issued a letter of credit of $36 million, leaving $839 million available.

Dunkirk Power LLC Tax-Exempt Bonds

On February 1, 2010, the Company fixed the rate on the Dunkirk bonds originally issued in April 2009, at 5.875%. In addition, the $59 million letter of credit issued by NRG in support of the bonds was cancelled and replaced with an NRG guarantee.

Debt Related to Capital Allocation Program

On March 3, 2010, the Company completed the early unwinding of the CSF I Debt by remitting a cash payment to Credit Suisse, or CS, of $242 million to settle the outstanding principal and interest, as compared to $249 million that would have been due at maturity in June 2010. As part of the unwind, CS returned to NRG 6,600,000 shares of NRG common stock borrowed under the Share Lending Agreement, or SLA, between the parties and released all 12,441,973 shares of NRG common stock held as collateral for the CSF I Debt. The 6,600,000 shares of NRG common stock were returned to treasury stock and will no longer be treated as outstanding for corporate law purposes. The Company has now settled all obligations related to the CSF I and II Debt entered into in 2006, as amended from time to time, as well as the SLA entered into in February 2009.

Blythe Credit Agreement

On June 24, 2010, NRG Solar Blythe LLC, or Blythe, entered into a credit agreement with a bank, or the Blythe Credit Agreement, for a $30 million term loan which has an interest rate of LIBOR plus an applicable margin which escalates 0.25% every three years and ranges from 2.5% at closing to 3.75% in year fifteen. The term loan matures in June 2028, amortizes based upon a predetermined schedule, and is secured by all of the assets of Blythe. The bank has also issued two letters of credit on behalf of Blythe totaling approximately $6.4 million. Blythe pays an availability fee of 100% of the applicable margin on these issued letters of credit.

Also related to the Blythe Credit Agreement, on June 25, 2010, Blythe entered into a fixed for floating interest rate swap for 75% of the outstanding term loan amount, intended to hedge the risks associated with floating interest rates. Blythe will pay its counterparty the equivalent of a 3.563% fixed interest payment on a predetermined notional value, and Blythe will receive quarterly the equivalent of a floating interest payment based on a three month LIBOR calculated on the same notional value. All interest rate swap payments by Blythe and its counterparty are made quarterly and the LIBOR is determined in advance of each interest period. The notional amount of the swap, which matures on June 25, 2028, is $22 million and amortizes in proportion to the loan.

South Trent Financing Agreement

On June 14, 2010 NRG completed the acquisition of the South Trent, as discussed in Note 4, *Business Acquisitions and Dispositions*. As part of the purchase price consideration, South Trent entered into the Amended and Restated Financing Agreement, or Financing Agreement, with a group of lenders, which matures on June 14, 2020. The Financing Agreement includes a $79 million term loan, as well as a $10 million letter of credit facility in support of the PPA, for which the full amount had been issued as of June 30, 2010. The Financing Agreement also provides for up to $8 million in additional letter of credit facilities, none of which are utilized as of June 30, 2010. The term loan accrues interest at LIBOR plus a margin based upon a grid, which is initially 2.50% and increases every two years by 12.5 basis points. The term loan amortizes quarterly based upon a predetermined schedule with the unamortized portion due at maturity.

Under the terms of the Financing Agreement, South Trent was required to enter into interest rate protection agreements that would fix the interest rate for a minimum of 75% of the outstanding principal amount. Accordingly, on June 14, 2010, South Trent entered into five interest rate swaps, intended to hedge the risks associated with floating interest rates. For each of the interest rate swaps, South Trent will pay its counterparty the equivalent of a 3.265% fixed interest payment on a predetermined notional value, and South Trent will receive the quarterly equivalent of a floating interest payment based on a three month LIBOR calculated on the same notional value. All interest rate swap payments by South Trent and its counterparties are made quarterly and the LIBOR is determined in advance of each interest period. The total notional amount of these swaps, which mature on June 14, 2020, is $59 million. The swaps amortize in proportion to the loan.

South Trent also entered into a series of forward-starting interest rate swaps that will become effective June 14, 2020, and are effective for eight years. The swaps are intended to hedge the risks associated with floating interest rates. For each of the interest rate swaps, South Trent will pay its counterparty the equivalent of a 4.95% fixed interest payment on a predetermined notional value, and receive the quarterly equivalent of a floating interest payment based on a three month LIBOR calculated on the same notional value. All interest rate swap payments by South Trent and its counterparties will be made quarterly and the LIBOR is determined in advance of each interest period. The total notional amount of these swaps, which will mature on June 14, 2028, is $21 million.

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NRG Thermal Financing

On June 22, 2010 NRG Thermal s largest subsidiary, NRG Energy Center Minneapolis LLC, or NRG Thermal Minneapolis, issued $100 million of 5.95% Series C notes due June 23, 2025, or the Series C Notes. The Series C Notes are secured by substantially all of the assets of NRG Energy Center Minneapolis. NRG Thermal has guaranteed the indebtedness and its guarantee is secured by a pledge of the equity interest in all of NRG Thermal s subsidiaries. At the same time, NRG Thermal amended agreements for its other outstanding notes to conform to the covenants of the Series C Notes. The proceeds of the loan were used to finance the acquisition of Northwind Phoenix, as discussed in Note 4, *Business Acquisitions and Dispositions.*

GenConn Energy LLC related financings

NRG Connecticut Peaking Development LLC made funding requests under the equity bridge loan, or EBL, during the quarter. The EBL is backed by a letter of credit issued by NRG under its Funded Letter of Credit Facility equal to 104% of the amount outstanding. The proceeds of the EBL received through June 30, 2010, were $115 million and the remaining amounts will be drawn as necessary to fund interest on the EBL as the maximum amount permitted to be drawn for project costs for both projects has been met. Of the $115 million, $55 million was drawn to fund Devon project costs and will become due and payable upon the commercial operation date, or COD, of the Devon project, which is expected to occur in the third quarter of 2010.

Borrowings of an equity method investment In April 2009, GenConn secured financing for 50% of the Devon and Middletown project construction costs through a seven-year term loan facility, and also entered into a five-year revolving working capital loan and letter of credit facility, which collectively with the term loan is referred to as the GenConn Facility. The aggregate credit amount secured under the GenConn Facility, which is non-recourse to NRG, is $291 million, including $48 million for the revolving facility. In August 2009, GenConn began to draw under the GenConn Facility to cover costs related to the Devon project, and in June 2010 GenConn began to draw for the Middletown project. As of June 30, 2010, $109 million had been drawn.

NINA Financing

On May 28, 2010, NINA borrowed $3 million under the TANE Facility. On June 1, 2010, NINA repaid $20 million outstanding under its revolving credit facility, and the facility was terminated.

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Note 9 Changes in Capital Structure

The following table reflects the changes in NRG s common stock issued and outstanding during the six months ended June 30, 2010:

	Authorized	Issued	Treasury	Outstanding
Balance as of December 31, 2009	500,000,000	295,861,759	(41,866,451)	253,995,308
Shares issued under LTIP		179,259		179,259
Shares issued under NRG Employee Stock Purchase Plan, or ESPP			54,845	54,845
Capital Allocation Plan			(2,214,000)	(2,214,000)
Shares returned by affiliates of CS			(6,600,000)	(6,600,000)
4% Preferred Stock conversion		7,701,450		7,701,450
Balance as of June 30, 2010	500,000,000	303,742,468	(50,625,606)	253,116,862

Employee Stock Purchase Plan

As of June 30, 2010, there were 363,623 shares of treasury stock reserved for issuance under the ESPP. In July 2010, 66,145 shares of common stock were issued to employee accounts from treasury stock.

2010 Capital Allocation Plan

As part of the Company s 2010 Capital Allocation Plan, the Company repurchased $50 million of NRG s common stock during the quarter ended June 30, 2010. NRG intends to complete the remainder of its $180 million of share repurchases by the end of 2010, subject to market prices, financial restrictions under the Company s debt facilities and as permitted by securities laws.

Share Lending Agreements

As part of the CSF I Debt unwind on March 3, 2010, CS returned to NRG 6,600,000 shares of NRG common stock borrowed under the SLA between the parties. The 6,600,000 shares of NRG common stock were returned to treasury stock and will no longer be treated as outstanding for corporate law purposes. See Note 8, *Long-Term Debt*, to this Form 10-Q for more information.

4% Preferred Stock

As of January 21, 2010, the Company completed the redemption of all remaining outstanding shares of 4% Preferred Stock, with holders converting 154,029 Preferred Stock shares into 7,701,450 shares of common stock and the Company redeeming 28 Preferred Stock shares for $28 thousand in cash.

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Note 10 Equity Compensation

Non-Qualified Stock Options, or NQSOs

The following table summarizes the Company s NQSO activity as of June 30, 2010, and changes during the six months then ended:

	Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (In millions)
Outstanding as of December 31, 2009	4,793,585	$ 25.07	
Granted	754,200	23.79	
Exercised	(111,331)	22.12	
Forfeited	(331,669)	30.16	
Outstanding at June 30, 2010	5,104,785	24.61	$ 10
Exercisable at June 30, 2010	3,288,301	$ 23.65	$ 10

The weighted average grant date fair value of NQSOs granted for the six months ended June 30, 2010, was $10.67.

Restricted Stock Units, or RSUs

The following table summarizes the Company s non-vested RSU awards as of June 30, 2010, and changes during the six months then ended:

	Units	Weighted Average Grant-Date Fair Value Per Unit
Non-vested as of December 31, 2009	1,614,769	$ 30.78
Granted	352,600	23.66
Vested	(68,240)	28.56
Forfeited	(109,180)	30.12
Non-vested as of June 30, 2010	1,789,949	$ 29.50

Performance Units, or PUs

The following table summarizes the Company s non-vested PU awards as of June 30, 2010, and changes during the six months then ended:

	Units	Weighted Average Grant- Date Fair Value Per Unit
Non-vested as of December 31, 2009	617,300	$ 24.27
Granted	348,500	23.81

Forfeited	(194,400)	22.73
Non-vested as of June 30, 2010	771,400	$ 24.45

In the six months ended June 30, 2010, there were no performance unit payouts in accordance with the terms of the performance units.

Deferral Stock Units, or DSUs

The following table summarizes the Company s outstanding DSU awards as of June 30, 2010, and changes during the six months then ended:

	Units	**Weighted Average Grant- Date Fair Value Per Unit**
Outstanding as of December 31, 2009	304,049	$ 19.34
Granted	59,067	22.18
Conversions	(28,395)	21.77
Outstanding as of June 30, 2010	334,721	$ 19.63

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Note 11 Earnings Per Share

Basic earnings per share attributable to NRG common stockholders is computed by dividing net income attributable to NRG Energy Inc. adjusted for accumulated preferred stock dividends by the weighted average number of common shares outstanding. Shares issued and treasury shares repurchased during the year are weighted for the portion of the year that they were outstanding.

Diluted earnings per share attributable to NRG common stockholders is computed in a manner consistent with that of basic earnings per share while giving effect to all potentially dilutive common shares that were outstanding during the period.

On March 3, 2010, as part of the CSF I Debt unwind, CS returned 6,600,000 shares of NRG common stock borrowed under the SLA between the parties. These shares had not been treated as outstanding for earnings per share purposes because CS was required to return all borrowed shares (or identical shares) upon termination of the SLA. See Note 8, *Long-Term Debt*, to this Form 10-Q, for more information on the SLA.

The reconciliation of basic earnings per common share to diluted earnings per share attributable to NRG is as follows:

	Three months ended June 30,		Six months ended June 30,	
(In millions, except per share data)	**2010**	**2009**	**2010**	**2009**
Basic earnings per share attributable to NRG common stockholders				
Numerator:				
Net income attributable to NRG Energy, Inc.	$ 211	$ 433	$ 269	$ 631
Preferred stock dividends	(3)	(7)	(5)	(21)
Net income attributable to NRG Energy, Inc. available to common stockholders	$ 208	$ 426	$ 264	$ 610
Denominator:				
Weighted average number of common shares outstanding	255	253	254	245
Basic earnings per share:				
Net income attributable to NRG Energy, Inc.	$0.82	$1.68	$1.04	$2.49
Diluted earnings per share attributable to NRG common stockholders				
Numerator:				
Net income available to common stockholders	$ 208	$ 426	$ 264	$ 610
Add preferred stock dividends for dilutive preferred stock		4		14
Net income attributable to NRG Energy, Inc. available to common stockholders	$ 208	$ 430	$ 264	$ 624
Denominator:				
Weighted average number of common shares outstanding	255	253	254	245
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	1	1	1	1

Incremental shares attributable to assumed conversion features of outstanding preferred stock (if-converted method)		21	1	29
Total dilutive shares	256	275	256	275
Diluted earnings per share:				
Net income attributable to NRG Energy, Inc.	$0.81	$1.56	$1.03	$2.27

The following table summarizes NRG s outstanding equity instruments that were anti-dilutive and not included in the computation of the Company s diluted earnings per share for the three and six months ended June 30:

	Three months ended June 30,		**Six months ended June 30,**	
(In millions of shares)	**2010**	**2009**	**2010**	**2009**
Equity compensation NQSOs and PUs	6	5	6	5
Embedded derivative of 3.625% redeemable perpetual preferred stock	16	16	16	16
Embedded derivative of CSF II Debt		8		8
Total	22	29	22	29

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Note 12 Segment Reporting

NRG s segment structure has changed to reflect the Company s acquisition of Reliant Energy along with the previously reported core areas of operation which are primarily the geographic regions of the Company s wholesale power generation, thermal and chilled water business, and corporate activities. Within NRG s wholesale power generation operations, there are distinct components with separate operating results and management structures for the following regions: Texas, Northeast, South Central, West and International.

(In millions)		**Wholesale Power Generation**								
Three months ended June 30, 2010	**Reliant Energy**	**Texas[(a)]**	**Northeast**	**South Central**	**West**	**International**	**Thermal**	**Corporate**	**Elimination**	**Total**
Operating revenues	$1,282	$ 692	$ 205	$152	$ 32	$ 30	$ 27	$ (4)	$ (283)	$ 2,133
Depreciation and amortization	29	124	31	16	3		3	2		208
Equity in earnings of unconsolidated affiliates		1	(1)		1	11		(1)		11
Income/(loss) before income taxes	277	157	(2)	4	8	31	(2)	(147)	1	327
Net income/(loss)	277	157	(2)	4	8	21	(2)	(254)	1	210
Net loss attributable to non-controlling interest		(1)								(1)
Net income/(loss) attributable to NRG Energy, Inc.	$ 277	$ 158	$ (2)	$ 4	$ 8	$ 21	$ (2)	$ (254)	$ 1	$ 211
Total assets	$1,930	$13,363	$1,843	$884	$372	$672	$328	$27,303	$(21,592)	$25,103

(a) Includes inter-segment sales of $281 million to Reliant Energy.

(In millions)		**Wholesale Power Generation**								
Three months ended June 30, 2009	**Reliant Energy[(a)]**	**Texas[(b)]**	**Northeast**	**South Central**	**West**	**International**	**Thermal**	**Corporate**	**Elimination**	**Total**
Operating revenues	$1,175	$619	$237	$139	$42	$ 34	$28	$ 32	$ (69)	$2,237
Depreciation and amortization	43	117	30	17	2		3	1		213
Equity in earnings/(loss) of unconsolidated affiliates		(7)			3	9				5
Income/(loss) from continuing operations	414	107	42	(9)	19	128		(119)		582

before income taxes										
Net income/(loss)	233	98	42	(9)	19	125		(76)		432
Net loss attributable to non-controlling interest		(1)								(1)
Net income/(loss) attributable to NRG Energy, Inc.	$ 233	$ 99	$ 42	$ (9)	$19	$ 125	$	$ (76)	$	$ 433

(a) Reliant Energy results are for the period May 1, 2009, to June 30, 2009.

(b) Includes inter-segment sales of $69 million to Reliant Energy.

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(In millions) Six months ended June 30, 2010	Reliant Energy	Wholesale Power Generation Texas[a]	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
Operating revenues	$2,458	$1,562	$484	$295	$67	$ 65	$63	$ (2)	$ (644)	$4,348
Depreciation and amortization	59	241	63	32	6		5	4		410
Equity in earnings of unconsolidated affiliates		11	(1)		1	15		(1)		25
Income/(loss) from continuing operations before income taxes	89	532	50		14	41	2	(279)	1	450
Net income/(loss)	89	532	50		14	29	2	(449)	1	268
Net loss attributable to non-controlling interest		(1)								(1)
Net income/(loss) attributable to NRG Energy, Inc.	$ 89	$ 533	$ 50	$	$14	$ 29	$ 2	$(449)	$ 1	$ 269

(a) Includes inter-segment sales of $642 million to Reliant Energy.

In millions) Six months ended June 30, 2009	Reliant Energy[a]	Wholesale Power Generation Texas[b]	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
Operating revenues	$1,175	$1,544	$701	$301	$70	$ 68	$70	$ 36	$ (70)	$3,895
Depreciation and amortization	43	234	59	34	4		5	3		382
Equity in earnings/(losses) of unconsolidated affiliates		(3)			4	26				27
Income/(loss) from continuing operations before income taxes	414	485	253	(8)	16	142	4	(228)		1,078
Net income/(loss)	233	315	253	(8)	16	137	4	(320)		630
Net loss attributable to non-controlling interest		(1)								(1)

Net income/(loss) attributable to NRG Energy, Inc.	$ 233	$ 316	$ 253	$ (8)	$ 16	$ 137	$ 4	$ (320)	$	$ 631

(a) Reliant Energy results are for the period May 1, 2009, to June 30, 2009.

(b) Includes inter-segment sales of $69 million to Reliant Energy.

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Note 13 Income Taxes

Effective Tax Rate

The Company s Income tax provision consisted of the following:

(In millions except otherwise noted)	Three months ended June 30, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Income tax expense	$ 117	$ 150	$ 182	$ 448
Effective tax rate	35.8%	25.8%	40.4%	41.5%

For the three months ended June 30, 2010, NRG s overall effective tax rate was different than the statutory rate of 35% primarily due to state and local income taxes as well as recording federal and state tax expense and interest for unrecognized tax benefits. For the three months ended June 30, 2009, NRG s effective tax rate was different than the statutory rate of 35% primarily due to a net state and local income tax benefit as a result of the Reliant Energy acquisition, and the sale of the MIBRAG facility.

For the six months ended June 30, 2010, NRG s overall effective tax rate was different than the statutory rate of 35% primarily due to state and local income taxes as well as recording federal and state tax expense and interest for unrecognized tax benefits. For the six months ended June 30, 2009, NRG s overall effective tax rate was different than the statutory rate of 35% primarily due to an increase in valuation allowance as a result of capital losses generated in the six month period for which there were no projected capital gains or available tax planning strategies. Furthermore, the effective tax rate was decreased by the sale of the MIBRAG facility as well as a net state and local income tax benefit as a result of the Reliant Energy acquisition.

Unrecognized tax benefits

As of June 30, 2010, NRG has recorded a $512 million non-current tax liability for unrecognized tax benefits, primarily resulting from taxable earnings for the period for which there are no net operating losses available to offset for financial statement purposes. NRG has accrued interest related to these unrecognized tax benefits of approximately $17 million for the six months ended June 30, 2010, and has accrued approximately $34 million since adoption. The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense.

The Company continues to be under examination by the Internal Revenue Service for the years 2004 through 2006, as well as various state jurisdictions for multiple years.

Tax Receivable and Payable

As of June 30, 2010, NRG recorded a current tax payable of approximately $22 million that represents a tax liability due for domestic state taxes of approximately $14 million, as well as foreign taxes payable of approximately $8 million. In addition, as of June 30, 2010, NRG had a domestic tax receivable of $77 million for property tax refunds primarily due to the New York State Empire Zone program.

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Note 14 Benefit Plans and Other Postretirement Benefits

NRG Defined Benefit Plans

NRG sponsors and operates three defined benefit pension and other postretirement plans. The NRG Plan for Bargained Employees and the NRG Plan for Non-Bargained Employees are maintained solely for eligible legacy NRG participants. A third plan, the Texas Genco Retirement Plan, is maintained for participation solely by eligible employees. The total amount of employer contributions paid for the six months ended June 30, 2010, was $11 million. NRG expects to make approximately $7 million in further contributions for the remainder of 2010.

The net periodic pension cost related to all of the Company s defined benefit pension plans includes the following components:

	Defined Benefit Pension Plans			
	Three months ended June 30,		Six months ended June 30,	
(In millions)	**2010**	**2009**	**2010**	**2009**
Service cost benefits earned	$ 4	$ 3	$ 7	$ 7
Interest cost on benefit obligation	5	5	10	10
Prior service cost		1		1
Expected return on plan assets	(6)	(4)	(10)	(8)
Net periodic benefit cost	$ 3	$ 5	$ 7	$ 10

The net periodic cost related to all of the Company s other postretirement benefits plans includes the following components:

	Other Postretirement Benefits Plans			
	Three months ended June 30,		Six months ended June 30,	
(In millions)	**2010**	**2009**	**2010**	**2009**
Service cost benefits earned	$	$1	$ 1	$ 2
Interest cost on benefit obligation	2	1	3	3
Net periodic benefit cost	$2	$2	$ 4	$ 5

STP Defined Benefit Plans

NRG has a 44% undivided ownership interest in South Texas Project, or STP. South Texas Project Nuclear Operating Company, or STPNOC, which operates and maintains STP, provides its employees a defined benefit pension plan as well as postretirement health and welfare benefits. Although NRG does not sponsor the STP plan, it reimburses STPNOC for 44% of the contributions made towards its retirement plan obligations. The total amount of employer contributions reimbursed to STPNOC for the six months ended June 30, 2010 was $1 million.

The Company recognized net periodic costs related to its 44% interest in STP defined benefits as follows:

	Three months ended June 30,		Six months ended June 30,	
(In millions)	**2010**	**2009**	**2010**	**2009**
Net periodic benefit costs	$ 2	$ 2	$ 4	$ 5

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Note 15 Commitments and Contingencies

First and Second Lien Structure

NRG has granted first and second liens to certain counterparties on substantially all of the Company s assets to reduce the amount of cash collateral and letters of credit that it would otherwise be required to post from time to time to support its obligations under out-of-the-money hedge agreements for forward sales of power or MWh equivalents. The Company s lien counterparties may have a claim on NRG s assets to the extent market prices exceed the hedged price. As of June 30, 2010, all hedges under the first and second liens were in-the-money on a counterparty aggregate basis.

Nuclear Innovation North America, LLC

CPS Settlement On March 1, 2010, an agreement was reached with CPS for NINA to acquire a controlling interest in the STP Units 3 and 4 Project through a settlement of litigation between the parties. As part of the agreement, NINA increased its ownership in the STP Units 3 and 4 Project from 50% to 92.375% and assumed full management control of the project. NRG also will pay $80 million to CPS, subject to the United States Department of Energy s, or U.S. DOE, approval of a fully executed term sheet for a conditional U.S. DOE loan guarantee. The first $40 million would be promptly paid after acceptance of the guarantee with the remaining $40 million paid six months later. NRG also agreed to donate an additional $10 million, unconditionally, over four years in annual payments of $2.5 million to the Residential Energy Assistance Partnership, or REAP, in San Antonio. The first $2.5 million payment to REAP was made on March 17, 2010. In connection with the agreement, the Company capitalized $90 million to construction in progress within property, plant and equipment, and as of June 30, 2010, $87.5 million in liabilities remains on the condensed consolidated balance sheet for the obligations to CPS and REAP. As part of the agreement with CPS, all litigation was dismissed with prejudice.

NINA Investment and Option Agreement On May 10, 2010, NINA and Tokyo Electric Power Company of Japan, or TEPCO, signed an Investment and Option Agreement whereby TEPCO agreed to acquire up to a 20% interest in NINA Investments Holdings LLC, or Holdings, a wholly-owned subsidiary of NINA, which indirectly holds NINA s ownership interest in the STP Units 3 and 4 Project. TEPCO will initially invest $155 million for a 10% share of Holdings, which includes a $30 million option premium payment to Holdings. This option, which expires approximately one year from the date of signing the Investment and Option Agreement, will enable TEPCO to buy an additional 10% of Holdings for another payment of $125 million. Pursuant to the terms of the Agreement, the closing is contingent upon NINA s acceptance of a U.S. DOE loan guarantee commitment. Upon its initial investment, TEPCO will hold a 9.238% interest in the STP Units 3 and 4 Project, diluting NINA s investment to 83.137% (75.11% for NRG). If TEPCO exercises its option to increase its ownership of Holdings another 10%, it will own 18.475% of the STP Units 3 and 4 Project, diluting NINA s investment to 73.90% (66.8% for NRG).

U.S. DOE Loan Guarantee In early 2010, NRG announced that if the STP Units 3 and 4 Project did not receive a loan guarantee from the U.S. DOE in a timely fashion, it was the intention of the Company both to reduce substantially its commitment to fund on-going project expenditures as well as to reduce development spending on the project overall while the outcome of the loan guarantee was uncertain. At the end of the second quarter, with the outcome of the loan guarantee uncertain, NRG began to curtail substantially its funding of on-going development expenses, immediately reducing its spend by approximately 70%. Working with NRG s partner (which agreed to step-up its commitment) and with other counterparties involved in the project, NRG also reduced the current spend rate on project development but did so in a manner which allowed the project to stay on its current schedule. NRG presently is in discussions with its partner and counterparties about a second phase of spending reductions. Should NRG and its partners withdraw support from the project this may result in a reassessment of the probability of success of the project and an impairment of the value of the capitalized assets for STP Units 3 and 4. An impairment to NRG would result in a permanent write-down of $498 million of construction-in-progress capitalized through June 30, 2010, plus any amounts capitalized through the impairment date. The likelihood of NINA receiving a loan guarantee is largely dependent upon additional appropriations for nuclear development by Congress or other means of properly securing the necessary funding for additional nuclear loan guarantee volume. On July 1, 2010, the U.S. House of Representatives passed an Emergency Supplemental Appropriations bill for fiscal year 2010, which included an additional $9 billion in loan guarantee authority for nuclear power facilities. The $9 billion in nuclear loan guarantee volume accelerates into 2010 a portion of the $36 billion in additional loan guarantee authority requested by the Obama administration for fiscal year 2011. The legislation passed by the House of Representatives, however, was rejected by the U.S. Senate. If Congress fails to agree on the necessary appropriation this session, the required funding will be subject to the normal fiscal year 2011 budget appropriation process, which as currently contemplated, would provide enough appropriations for the benefit of a loan guarantee to the STP Units 3 and 4 Project.

Contingencies

Set forth below is a description of the Company s material legal proceedings. The Company believes that it has valid defenses to these legal proceedings and intends to defend them vigorously. NRG records reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss, or range of loss, can be reasonably estimated. In addition legal costs are expensed as incurred. Management has assessed each of the following matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought, and the probability of success. Unless specified below, the Company is unable to predict the outcome of these legal proceedings or reasonably estimate the scope or amount of any associated costs and potential liabilities. As additional information becomes available, management adjusts its assessment and estimates of such contingencies accordingly. Because litigation is subject to inherent uncertainties and unfavorable rulings or developments, it is possible that the ultimate resolution of the Company s liabilities and contingencies could be at amounts that are different from its currently recorded reserves and that such difference could be material.

In addition to the legal proceedings noted below, NRG and its subsidiaries are party to other litigation or legal proceedings arising in the ordinary course of business. In management s opinion, the disposition of these ordinary course matters will not materially adversely affect NRG s consolidated financial position, results of operations, or cash flows.

California Department of Water Resources

This matter concerns, among other contracts and other defendants, the California Department of Water Resources, or CDWR and its wholesale power contract with subsidiaries of WCP (Generation) Holdings, Inc., or WCP. The case originated with a February 2002 complaint filed by the State of California alleging that many parties, including WCP subsidiaries, overcharged the State of California. For WCP, the alleged overcharges totaled approximately $940 million for 2001 and 2002. The complaint demanded that the Federal Energy Regulatory Commission, or FERC abrogate the CDWR contract and sought refunds associated with revenues collected under the contract. In 2003, the FERC rejected this complaint, denied rehearing, and the case was appealed to the U.S. Court of Appeals for the Ninth Circuit where oral argument was held on December 8, 2004. On December 19, 2006, the Ninth Circuit decided that in the FERC s review of the contracts at issue, the FERC could not rely on the *Mobile-Sierra* standard presumption of just and reasonable rates, where such contracts were not reviewed by the FERC with full knowledge of the then existing market conditions. WCP and others sought review by the U.S. Supreme Court. WCP s appeal was not selected, but instead held by the Supreme Court. In the appeal that was selected by the Supreme Court, on June 26, 2008 the Supreme Court ruled: (i) that the *Mobile-Sierra* public interest standard of review applied to contracts made under a seller s market-based rate authority; (ii) that the public interest bar required to set aside a contract remains a very high one to overcome; and (iii) that the *Mobile-Sierra* presumption of contract reasonableness applies when a contract is formed during a period of market dysfunction unless (a) such market conditions were caused by the illegal actions of one of the parties or (b) the contract negotiations were tainted by fraud or duress. In this related case, the U.S. Supreme Court affirmed the Ninth Circuit s decision agreeing that the case should be remanded to the FERC to clarify the FERC s 2003 reasoning regarding its rejection of the original complaint relating to the financial burdens under the contracts at issue and to alleged market manipulation at the time these contracts were formed. As a result, the U.S. Supreme Court then reversed and remanded the WCP CDWR case to the Ninth Circuit for treatment consistent with its June 26, 2008 decision in the related case. On October 20, 2008, the Ninth Circuit asked the parties in the remanded CDWR case, including WCP and the FERC, whether that Court should answer a question the U.S. Supreme Court did not address in its June 26, 2008 decision; whether the *Mobile-Sierra* doctrine applies to a third-party that was not a signatory to any of the wholesale power contracts, including the CDWR contract, at issue in that case. Without answering that reserved question, on December 4, 2008, the Ninth Circuit vacated its prior opinion and remanded the WCP CDWR case back to the FERC for proceedings consistent with the U.S. Supreme Court s June 26, 2008 decision. On December 15, 2008, WCP and the other seller-defendants filed with the FERC a Motion for Order Governing Proceedings on Remand. On January 14, 2009, the Public Utilities Commission of the State of California filed an Answer and Cross Motion for an Order Governing Procedures on Remand and on January 28, 2009, WCP and the other seller-defendants filed their reply.

At this time, while NRG cannot predict with certainty whether WCP will be required to make refunds for rates collected under the CDWR contract or estimate the range of any such possible refunds, a reconsideration of the CDWR contract by the FERC with a resulting order mandating significant refunds could have a material adverse impact on NRG s financial position, statement of operations, and statement of cash flows. As part of the 2006 acquisition of Dynegy s 50% ownership interest in WCP, WCP and NRG assumed responsibility for any risk of loss arising from this case, unless any such loss was deemed to have resulted from certain acts of gross negligence or willful misconduct on the part of Dynegy, in which case any such loss would be shared equally between WCP and Dynegy.

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On January 14, 2010, the U.S. Supreme Court issued its decision in an unrelated proceeding involving the *Mobile-Sierra* doctrine that will affect the standard of review applied to the CDWR contract on remand before the FERC. In *NRG Power Marketing v. Maine Public Utilities Commission*, the Supreme Court held that the *Mobile-Sierra* presumption regarding the reasonableness of contract rates does not depend on the identity of the complainant who seeks a FERC investigation/refund.

Louisiana Generating, LLC

On February 11, 2009, the U.S. Department of Justice, or U.S. DOJ, acting at the request of the U.S. Environmental Protection Agency, or U.S. EPA, commenced a lawsuit against Louisiana Generating, LLC, or LaGen, in federal district court in the Middle District of Louisiana alleging violations of the Clean Air Act, or CAA, at the Big Cajun II power plant. This is the same matter for which Notices of Violation, or NOVs, were issued to LaGen on February 15, 2005, and on December 8, 2006. Specifically, it is alleged that in the late 1990 s, several years prior to NRG s acquisition of the Big Cajun II power plant from the Cajun Electric bankruptcy and several years prior to the NRG bankruptcy, modifications were made to Big Cajun II Units 1 and 2 by the prior owners without appropriate or adequate permits and without installing and employing the best available control technology, or BACT, to control emissions of nitrogen oxides and/or sulfur dioxides. The relief sought in the complaint includes a request for an injunction to: (i) preclude the operation of Units 1 and 2 except in accordance with the CAA; (ii) order the installation of BACT on Units 1 and 2 for each pollutant subject to regulation under the CAA; (iii) obtain all necessary permits for Units 1 and 2; (iv) order the surrender of emission allowances or credits; (v) conduct audits to determine if any additional modifications have been made which would require compliance with the CAA s Prevention of Significant Deterioration program; (vi) award to the Department of Justice its costs in prosecuting this litigation; and (vii) assess civil penalties of up to $27,500 per day for each CAA violation found to have occurred between January 31, 1997, and March 15, 2004, up to $32,500 for each CAA violation found to have occurred between March 15, 2004, and January 12, 2009, and up to $37,500 for each CAA violation found to have occurred after January 12, 2009.

On April 27, 2009, LaGen made several filings. It filed an objection in the Cajun Electric Cooperative Power, Inc. s bankruptcy proceeding in the U.S. Bankruptcy Court for the Middle District of Louisiana to seek to prevent the bankruptcy from closing. It also filed a complaint in the same bankruptcy proceeding in the same court seeking a judgment that: (i) it did not assume liability from Cajun Electric for any claims or other liabilities under environmental laws with respect to Big Cajun II that arose, or are based on activities that were undertaken, prior to the closing date of the acquisition; (ii) it is not otherwise the successor to Cajun Electric; and (iii) Cajun Electric and/or the Bankruptcy Trustee are exclusively liable for the violations alleged in the February 11, 2009, lawsuit to the extent that such claims are determined to have merit. On April 15, 2010, the bankruptcy court signed an order granting LaGen s stipulation of voluntary dismissal without prejudice of its adversary bankruptcy action.

On June 8, 2009, the parties filed a joint status report in the U.S. DOJ lawsuit setting forth their views of the case and proposing a trial schedule. On June 18, 2009, LaGen filed a motion to bifurcate the U.S. DOJ lawsuit into separate liability and remedy phases, and on June 30, 2009, the U.S. DOJ filed its opposition. On April 28, 2010, the district court entered a Joint Case Management Order, and LaGen s motion for bifurcation was effectively granted, in that the district court set trial on the liability phase for mid-2011, and, if necessary, trial on the damages (remedy) phase for mid-2012. On August 24, 2009, LaGen filed a motion to dismiss this lawsuit, and on September 25, 2009, the U.S. DOJ filed its opposition to the motion to dismiss. On February 18, 2010, the LDEQ filed a motion to intervene in the above lawsuit and a complaint against LaGen for alleged violations of Louisiana s Prevention of Significant Deterioration, or PSD regulations, and Louisiana s Title V operating permit program. LDEQ seeks substantially similar relief to that requested by the U.S. DOJ. On February 19, 2010, the district court granted LDEQ s motion to intervene. On April 26, 2010, LaGen filed a motion to dismiss LDEQ s complaint. On July 21, 2010, LaGen argued its motions to dismiss, while the U.S. DOJ and LDEQ argued in opposition to the motions. The judge ordered the parties to submit further briefing within thirty days.

On February 18, 2010, the Louisiana Department of Environmental Quality, or LDEQ, filed a motion to intervene in the above lawsuit and a complaint against LaGen for alleged violations of Louisiana s Prevention of Significant Deterioration, or PSD regulations and Louisiana s Title V operating permit program. LDEQ seeks substantially similar relief to that requested by the U.S. DOJ. On February 19, 2010, the district court granted LDEQ s motion to intervene. On April 26, 2010, LaGen filed a motion to dismiss LDEQ s complaint. On April 28, 2010, the district court entered a Joint Case Management Order in this matter. As a result of entering this order, LaGen s motion for bifurcation was effectively granted. As such, the first trial on liability will take place on or about May 2011. The second trial on the remedy will take place on or about March 2012. On July 21, 2010, LaGen argued its motions to dismiss, while the U.S. DOJ and LDEQ argued in opposition to the motions. The judge ordered the parties to submit further briefing within thirty days.

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Dunkirk Construction Litigation

In 2005, NRG entered into a Consent Decree with the New York State Department of Environmental Conservation whereby it agreed to reduce certain emissions generated by its Huntley and Dunkirk power plants. Pursuant to the Consent Decree, on November 21, 2007, Clyde Bergemann EEC, or CBEEC, and NRG entered into a firm fixed price contract for the supply of equipment, material and services for six fabric filters for NRG s Dunkirk Electric Power Generating Station. Subsequent to contracting with NRG, CBEEC subcontracted with Hohl Industrial Services, Inc., or Hohl, to perform steel erection and equipment installation at Dunkirk.

On August 28, 2009, Hohl filed its original complaint against NRG, its subsidiary Dunkirk Power LLC, or Dunkirk Power, and CBEEC among others for claims of breach of contract, quantum meruit, unjust enrichment and foreclosure of mechanics liens. As part of CBEEC s contractual obligation to NRG, CBEEC agreed to defend NRG, under a reservation of rights. CBEEC filed an answer to the above complaint on behalf of itself, NRG, and Dunkirk Power on October 5, 2009. On December 16, 2009, CBEEC filed a Motion for Summary Judgment on behalf of itself, NRG, and Dunkirk Power. On February 1, 2010, NRG and Dunkirk Power filed a Motion for Leave to file an Amended Answer with Cross-Claims against CBEEC. NRG asserted breach of contract claims seeking liquidated damages for the delays caused by CBEEC. NRG also retained its own counsel to represent its interest in the cross-claims and reserved its rights to seek reimbursement from CBEEC. On February 17, 2010, CBEEC filed an Amended Answer with Affirmative Defenses, Counterclaims and Cross-Claims against NRG, in which it sought $30 million alleging breach of contract, quantum meruit, unjust enrichment, and foreclosure of two mechanic s liens, as a result of alleged delays caused by NRG and Dunkirk Power. On March 5, 2010, CBEEC and NRG resolved their disputed cross-claims. In April 2010, the other parties to this litigation settled their disputes which settlement is expected to be final in the third quarter of 2010.

Excess Mitigation Credits

From January 2002 to April 2005, CenterPoint Energy applied excess mitigation credits, or EMCs, to its monthly charges to retail electric providers as ordered by the PUCT. The PUCT imposed these credits to facilitate the transition to competition in Texas, which had the effect of lowering the retail electric providers monthly charges payable to CenterPoint Energy. As indicated in its Petition for Review filed with the Supreme Court of Texas on June 2, 2008, CenterPoint Energy has claimed that the portion of those EMCs credited to Reliant Energy Retail Services, LLC, or RERS, a retail electric provider and NRG subsidiary acquired from RRI, totaled $385 million for RERS s Price to Beat Customers. It is unclear what the actual number may be. Price to Beat was the rate RERS was required by state law to charge residential and small commercial customers that were transitioned to RERS from the incumbent integrated utility company commencing in 2002. In its original stranded cost case brought before the PUCT on March 31, 2004, CenterPoint Energy sought recovery of all EMCs that were credited to all retail electric providers, including RERS, and the PUCT ordered that relief in its Order on Rehearing in Docket No. 29526, on December 17, 2004. After an appeal to state district court, the court entered a final judgment on August 26, 2005, affirming the PUCT s order with regard to EMCs credited to RERS. Various parties filed appeals of that judgment with the Court of Appeals for the Third District of Texas with the first such appeal filed on the same date as the state district court judgment and the last such appeal filed on October 10, 2005. On April 17, 2008, the Court of Appeals for the Third District reversed the lower court s decision ruling that CenterPoint Energy s stranded cost recovery should exclude only EMCs credited to RERS for its Price to Beat customers. On June 2, 2008, CenterPoint Energy filed a Petition for Review with the Supreme Court of Texas and on June 19, 2009, the Court agreed to consider the CenterPoint Energy appeal as well as two related petitions for review filed by other entities. Oral argument occurred on October 6, 2009.

In November 2008, CenterPoint Energy and Reliant Energy Inc., or REI, on behalf of itself and affiliates including RERS, agreed to suspend unexpired deadlines, if any, related to limitations periods that might exist for possible claims against REI and its affiliates if CenterPoint Energy is ultimately not allowed to include in its stranded cost calculation those EMCs previously credited to RERS. Regardless of the outcome of the Texas Supreme Court proceeding, NRG believes that any possible future CenterPoint Energy claim against RERS for EMCs credited to RERS would lack legal merit. No such claim has been filed.

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Note 16 Regulatory Matters

NRG operates in a highly regulated industry and is subject to regulation by various federal and state agencies. As such, NRG is affected by regulatory developments at both the federal and state levels and in the regions in which NRG operates. In addition, NRG is subject to the market rules, procedures and protocols of the various ISO markets in which NRG participates. These power markets are subject to ongoing legislative and regulatory changes that may impact NRG s wholesale and retail businesses.

In addition to the regulatory proceedings noted below, NRG and its subsidiaries are a party to other regulatory proceedings arising in the ordinary course of business or have other regulatory exposure. In management s opinion, the disposition of these ordinary course matters will not materially adversely affect NRG s consolidated financial position, results of operations, or cash flows.

PJM On June 18, 2009, FERC denied rehearing of its order dated September 19, 2008, dismissing a complaint filed by the Maryland Public Service Commission, or MDPSC, together with other load interests, against PJM challenging the results of the Reliability Pricing Model, or RPM transition Base Residual Auctions for installed capacity, held between April 2007 and January 2008. The complaint had sought to replace the auction-determined results for installed capacity for the 2008/2009, 2009/2010, and 2010/2011 delivery years with administratively-determined prices. On August 14, 2009, the MDPSC and the New Jersey Board of Public Utilities filed an appeal of FERC s orders to the U.S. Court of Appeals for the Fourth Circuit, and a successful appeal could disrupt the auction-determined results and create a refund obligation for market participants. The case has been transferred to the U.S. Court of Appeals for the DC Circuit.

Midwest ISO v. PJM On March 8, 2010, Midwest ISO filed a complaint against PJM seeking payments from PJM related to inter-market operations and settlements for congestion costs between the systems for the period from April 2005 to the present. If the Midwest ISO s allegations are true, PJM may have significant liability. If PJM makes any payments to the Midwest ISO related to these claims, PJM is expected to seek to recover the payments from entities that served load and held transmission congestion rights on PJM during the period in dispute, including NRG, which provided basic generation service and thus effectively served load. At this time, NRG s share of any payment by PJM is not expected to be material.

Retail (Replacement Reserve) On November 14, 2006, Constellation Energy Commodities Group, or Constellation, filed a complaint with the PUCT alleging that ERCOT misapplied the Replacement Reserve Settlement, or RPRS, Formula contained in the ERCOT protocols from April 10, 2006, through September 27, 2006. Specifically, Constellation disputed approximately $4 million in under-scheduling charges for capacity insufficiency asserting that ERCOT applied the wrong protocol. REPS, other market participants, ERCOT, and PUCT staff opposed Constellation s complaint. On January 25, 2008, the PUCT entered an order finding that ERCOT correctly settled the capacity insufficiency charges for the disputed dates in accordance with ERCOT protocols and denied Constellation s complaint. On April 9, 2008, Constellation appealed the PUCT order to the Civil District Court of Travis County, Texas and on June 19, 2009, the court issued a judgment reversing the PUCT order, finding that the ERCOT protocols were in irreconcilable conflict with each other. On July 20, 2009, REPS filed an appeal to the Third Court of Appeals in Travis County, Texas, thereby staying the effect of the trial court s decision. If all appeals are unsuccessful, on remand to the PUCT, it would determine the appropriate methodology for giving effect to the trial court s decision. It is not known at this time whether only Constellation s under-scheduling charges, the under-scheduling charges of all other QSEs that disputed REPS charges for the same time frame, the entire market, or some other approach would be used for any resettlement.

Under the PUCT ordered formula, Qualified Scheduling Entities, or QSEs, who under-scheduled capacity within any of ERCOT s four congestion zones were assessed under-scheduling charges which defrayed the costs incurred by ERCOT for RPRS that would otherwise be spread among all load-serving QSEs. Under the Court s decision, all RPRS costs would be assigned to all load-serving QSEs based upon their load ratio share without assessing any separate charge to those QSEs who under-scheduled capacity. If under-scheduling charges for capacity insufficient QSEs were not used to defray RPRS costs, REPS s share of the total RPRS costs allocated to QSEs would increase.

Note 17 Environmental Matters

The construction and operation of power projects are subject to stringent environmental and safety protection and land use laws and regulation in the United States. If such laws and regulations become more stringent, or new laws, interpretations or compliance policies apply and NRG s facilities are not exempt from coverage, the Company could be required to make modifications to further reduce potential environmental impacts. New legislation and regulations to mitigate the effects of Greenhouse Gases, or GHG including carbon dioxide, or CO_2 from power plants, are under consideration at the federal and state levels. In general, the effect of such future laws or regulations is expected to require the addition of pollution control equipment or the imposition of restrictions or additional costs on the Company s operations.

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures from 2010 through 2014 to meet NRG s environmental commitments will be approximately $0.9 billion and are primarily associated with controls on the Company s Big Cajun and Indian River facilities. These capital expenditures, in general, are related to installation of particulate, sulfur dioxide, or SO_2, nitrogen oxide, or NO_x, and mercury controls to comply with federal and state air quality rules and consent orders, as well as installation of Best Technology Available under a section of the Clean Water Act regulating cooling water intake structures, or Phase II 316(b) Rule. NRG continues to explore cost effective alternatives that can achieve desired results. This estimate reflects anticipated schedules and controls related to the Clean Air Interstate Rule, or CAIR, Clean Air Transport Rule, or CATR, Maximum Achievable Control Technology, or MACT for mercury, and the Phase II 316(b) Rule which are under remand to the U.S. EPA, and, as such, the full impact on the scope and timing of environmental retrofits from any new or revised regulations cannot be determined at this time.

NRG s current contracts with the Company s rural electrical customers in the South Central region allow for recovery of a portion of the regions capital costs once in operation, along with a capital return incurred by complying with new laws, including interest over the asset life of the required expenditures. The actual recoveries will depend, among other things, on the timing of the completion of the capital project and the remaining duration of the contracts.

Northeast Region

In January 2006, NRG s Indian River Operations, Inc. received a letter of informal notification from DNREC stating that it may be a potentially responsible party with respect to Burton Island Old Ash Landfill, a historic captive landfill located at the Indian River facility. On October 1, 2007, NRG signed an agreement with DNREC to investigate the site through the Voluntary Clean-up Program. On February 4, 2008, DNREC issued findings that no further action is required in relation to surface water and that a previously planned shoreline stabilization project would satisfactorily address shoreline erosion. The landfill itself will require a further Remedial Investigation and Feasibility Study to determine the type and scope of any additional work required. Until the Remedial Investigation and Feasibility Study is completed, the Company is unable to predict the impact of any required remediation. On May 29, 2008, DNREC requested that NRG s Indian River Operations, Inc. participate in the development and performance of a Natural Resource Damage Assessment, or NRDA, at the Burton Island Old Ash Landfill. NRG is currently working with DNREC and other trustees to close out the assessment phase.

Pursuant to a consent order dated September 25, 2007, between NRG and DNREC, NRG agreed to operate the four units at the Indian River plant in a manner that would limit the emissions of NO_x and SO_2, and to mothball Units 1 and 2 on May 1, 2011 and May 1, 2010, respectively. In addition, Units 3 and 4, with a combined generating capacity of approximately 565 MW, could not operate beyond December 31, 2011 unless appropriate control technology was installed on each unit. Unit 2 was mothballed as planned on May 1, 2010. On July 21, 2010, the court approved an amended consent order, pursuant to which NRG will retire Unit 3 (155 MW) by December 31, 2013, thereby extending the operable period of the unit by two years without installing additional control technology. Units 1, 2 and 4 are not affected by the amended consent order.

South Central Region

On February 11, 2009, the U.S. DOJ acting at the request of the U.S. EPA commenced a lawsuit against LaGen in federal district court in the Middle District of Louisiana alleging violations of the CAA at the Big Cajun II power plant. This is the same matter for which NOVs were issued to LaGen on February 15, 2005, and on December 8,

2006. Further discussion on this matter can be found in Note 15, *Commitments and Contingencies,* to this Form 10-Q, *Louisiana Generating, LLC.*

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Note 18 Condensed Consolidating Financial Information

As of June 30, 2010, the Company had outstanding $1.2 billion of 7.25% Senior Notes due 2014, $2.4 billion of 7.375% Senior Notes due 2016, $1.1 billion of 7.375% Senior Notes due 2017, and $700 million of 8.50% Senior Notes due 2019. These notes are guaranteed by certain of NRG s current and future wholly-owned domestic subsidiaries, or guarantor subsidiaries.

Unless otherwise noted below, each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of June 30, 2010:

Arthur Kill Power LLC
Astoria Gas Turbine Power LLC
Berrians I Gas Turbine Power LLC
Big Cajun II Unit 4 LLC
Cabrillo Power I LLC
Cabrillo Power II LLC
Carbon Management Solutions LLC
Clean Edge Energy LLC
Conemaugh Power LLC
Connecticut Jet Power LLC
Devon Power LLC
Dunkirk Power LLC
Eastern Sierra Energy Company
Elbow Creek Wind Project LLC
El Segundo Power, LLC
El Segundo Power II LLC
GCP Funding Company LLC
Huntley IGCC LLC
Huntley Power LLC
Indian River IGCC LLC
Indian River Operations Inc.
Indian River Power LLC
James River Power LLC
Keystone Power LLC
Langford Wind Power, LLC
Louisiana Generating LLC
Middletown Power LLC
Montville IGCC LLC
Montville Power LLC
NEO Corporation
NEO Freehold-Gen LLC
NEO Power Services Inc.
New Genco GP LLC
Norwalk Power LLC
NRG Affiliate Services Inc.
NRG Arthur Kill Operations Inc.
NRG Artesian Energy LLC
NRG Astoria Gas Turbine Operations Inc.
NRG Bayou Cove LLC
NRG Cabrillo Power Operations Inc.
NRG California Peaker Operations LLC
NRG Generation Holdings, Inc.
NRG Huntley Operations Inc.
NRG International LLC
NRG MidAtlantic Affiliate Services Inc.
NRG Middletown Operations Inc.
NRG Montville Operations Inc.
NRG New Jersey Energy Sales LLC
NRG New Roads Holdings LLC
NRG North Central Operations, Inc.
NRG Northeast Affiliate Services Inc.
NRG Norwalk Harbor Operations Inc.
NRG Operating Services Inc.
NRG Oswego Harbor Power Operations Inc.
NRG Power Marketing LLC
NRG Retail LLC
NRG Saguaro Operations Inc.
NRG South Central Affiliate Services Inc.
NRG South Central Generating LLC
NRG South Central Operations Inc.
NRG South Texas LP
NRG Texas LLC
NRG Texas C & I Supply LLC
NRG Texas Holding Inc.
NRG Texas Power LLC
NRG West Coast LLC
NRG Western Affiliate Services Inc.
Oswego Harbor Power LLC
Reliant Energy Power Supply, LLC
Reliant Energy Retail Holdings, LLC
Reliant Energy Retail Services, LLC
RE Retail Receivables, LLC
RERH Holdings, LLC
Reliant Energy Services Texas LLC
Reliant Energy Texas Retail LLC
Saguaro Power LLC
Somerset Operations Inc.
Somerset Power LLC
Texas Genco Financing Corp.
Texas Genco GP, LLC
Texas Genco Holdings, Inc.
Texas Genco LP, LLC

NRG Cedar Bayou Development Company LLC
NRG Connecticut Affiliate Services Inc.
NRG Construction LLC
NRG Devon Operations Inc.
NRG Dunkirk Operations, Inc.
NRG Energy Services LLC
NRG El Segundo Operations Inc.
Texas Genco Operating Services, LLC
Texas Genco Services, LP
Vienna Operations, Inc.
Vienna Power LLC
WCP (Generation) Holdings LLC
West Coast Power LLC

The non-guarantor subsidiaries include all of NRG s foreign subsidiaries and certain domestic subsidiaries. NRG conducts much of its business through and derives much of its income from its subsidiaries. Therefore, the Company s ability to make required payments with respect to its indebtedness and other obligations depends on the financial results and condition of its subsidiaries and NRG s ability to receive funds from its subsidiaries. Except for NRG Bayou Cove, LLC, which is subject to certain restrictions under the Company s Peaker financing agreements, there are no restrictions on the ability of any of the guarantor subsidiaries to transfer funds to NRG. In addition, there may be restrictions for certain non-guarantor subsidiaries.

The following condensed consolidating financial information presents the financial information of NRG, the guarantor subsidiaries and the non-guarantor subsidiaries in accordance with Rule 3-10 under the Securities and Exchange Commission s Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the guarantor subsidiaries or non-guarantor subsidiaries operated as independent entities.

In this presentation, NRG Energy, Inc. consists of parent company operations. Guarantor subsidiaries and non-guarantor subsidiaries of NRG are reported on an equity basis. For companies acquired, the fair values of the assets and liabilities acquired have been presented on a push-down accounting basis.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Three Months Ended June 30, 2010

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(a)	Consolidated Balance
Operating Revenues					
Total operating revenues	$2,066	$ 74	$	$ (7)	$2,133
Operating Costs and Expenses					
Cost of operations	1,283	53		(7)	1,329
Depreciation and amortization	202	4	2		208
Selling, general and administrative	72	2	65		139
Development costs		3	10		13
Total operating costs and expenses	1,557	62	77	(7)	1,689
Operating Income/(Loss)	509	12	(77)		444
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	15		332	(347)	
Equity in earnings of unconsolidated affiliates	1	10			11
Other income, net	2	14	3		19
Interest expense	(6)	(9)	(132)		(147)
Total other income/(expense)	12	15	203	(347)	(117)
Income/(Losses) Before Income Taxes	521	27	126	(347)	327
Income tax expense/(benefit)	190	12	(85)		117
Net Income	331	15	211	(347)	210
Less: Net loss attributable to noncontrolling interest	(1)				(1)
Net Income attributable to NRG Energy, Inc.	$ 332	$ 15	$ 211	$ (347)	$ 211

(a) All significant intercompany transactions have been eliminated in consolidation.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Six Months Ended June 30, 2010

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
Operating Revenues					
Total operating revenues	$4,193	$ 169	$	$ (14)	$4,348
Operating Costs and Expenses					
Cost of operations	2,856	119	7	(14)	2,968
Depreciation and amortization	392	14	4		410
Selling general and administrative	139	5	125		269
Development costs		6	16		22
Total operating costs and expenses	3,387	144	152	(14)	3,669
Gain on sale of assets			23		23
Operating Income/(Loss)	806	25	(129)		702
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	22		526	(548)	
Equity in earnings of unconsolidated affiliates	1	24			25
Other income, net	3	17	3		23
Interest expense	(11)	(23)	(266)		(300)
Total other income/(expense)	15	18	263	(548)	(252)
Income/(Losses) Before Income Taxes	821	43	134	(548)	450
Income tax expense/(benefit)	301	16	(135)		182
Net Income	520	27	269	(548)	268
Less: Net loss attributable to noncontrolling interest	(1)				(1)
Net Income attributable to NRG Energy, Inc.	$ 521	$ 27	$ 269	$ (548)	$ 269

(a) All significant intercompany transactions have been eliminated in consolidation.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
June 30, 2010

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
		ASSETS			
Current Assets					
Cash and cash equivalents	$ 34	$ 154	$ 1,980	$	$ 2,168
Funds deposited by counterparties	310				310
Restricted cash	1	12			13
Accounts receivable, net	876	33			909
Inventory	527	8			535
Derivative instruments valuation	1,800				1,800
Cash collateral paid in support of energy risk management activities	389	2			391
Prepayments and other current assets	62	55	240	(114)	243
Total current assets	3,999	264	2,220	(114)	6,369
Net property, plant and equipment	10,515	1,125	153		11,793
Other Assets					
Investment in subsidiaries	753	258	20,751	(21,762)	
Equity investments in affiliates	42	352			394
Capital leases and notes receivable, less current portion	5,626	431	3,169	(8,792)	434
Goodwill	1,713	3			1,716
Intangible assets, net	1,567	58	33	(32)	1,626
Nuclear decommissioning trust fund	360				360
Derivative instruments valuation	899		11		910
Restricted cash supporting funded letter of credit facility		1,300			1,300
Other non-current assets	39	13	149		201
Total other assets	10,999	2,415	24,113	(30,586)	6,941
Total Assets	$25,513	$ 3,804	$ 26,486	$ (30,700)	$25,103
		LIABILITIES AND STOCKHOLDERS EQUITY			
Current Liabilities					
Current portion of long-term debt and capital leases	$ 58	$ 159	$ 20	$ (58)	$ 179
Accounts payable	(3,111)	483	3,318		690

Derivative instruments valuation	1,434	2	48		1,484
Deferred income taxes	(4)		248		244
Cash collateral received in support of energy risk management activities	310				310
Accrued expenses and other current liabilities	345	33	302	(57)	623
Total current liabilities	(968)	677	3,936	(115)	3,530
Other Liabilities					
Long-term debt and capital leases	2,936	853	12,994	(8,792)	7,991
Funded letter of credit			1,300		1,300
Nuclear decommissioning reserve	309				309
Nuclear decommissioning trust liability	234				234
Deferred income taxes	2,231	(193)	(270)		1,768
Derivative instruments valuation	364	40	29		433
Out-of-market contracts	283	6		(31)	258
Other non-current liabilities	739	27	236		1,002
Total non-current liabilities	7,096	733	14,289	(8,823)	13,295
Total liabilities	6,128	1,410	18,225	(8,938)	16,825
3.625% Preferred Stock			248		248
Stockholders Equity	19,385	2,394	8,013	(21,762)	8,030
Total Liabilities and Stockholders Equity	$25,513	$ 3,804	$ 26,486	$ (30,700)	$25,103

(a) All significant intercompany transactions have been eliminated in consolidation.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2010

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
Cash Flows from Operating Activities					
Net income	$ 520	$ 27	$ 269	$ (548)	$ 268
Adjustments to reconcile net income to net cash provided by operating activities:					
Distributions and equity in (earnings)/losses of unconsolidated affiliates and consolidated subsidiaries	10	(11)	(489)	481	(9)
Depreciation and amortization	392	14	4		410
Provision for bad debts	22				22
Amortization of nuclear fuel	19				19
Amortization of financing costs and debt discount/premiums		3	12		15
Amortization of intangibles and out-of-market contracts	1				1
Changes in deferred income taxes and liability for unrecognized tax benefits	300	2	(123)		179
Changes in nuclear decommissioning trust liability	9				9
Changes in derivatives	(57)	2			(55)
Changes in collateral deposits supporting energy risk management activities	(30)				(30)
Loss/(gain) on sale of assets	12		(23)		(11)
Loss on sale of emission allowances	3				3
Amortization of unearned equity compensation			15		15
Changes in option premiums collected, net of acquisition	34				34
Cash (used)/provided by changes in other working capital, net of acquisitions	(505)	(75)	315		(265)
Net Cash Provided/(Used) by Operating Activities	730	(38)	(20)	(67)	605
Cash Flows from Investing Activities					
Intercompany (loans to)/receipts from subsidiaries	(739)		(142)	881	
Acquisition of businesses		(141)			(141)
Investment in subsidiaries		1,721	(1,721)		
Capital expenditures	(145)	(159)	(26)		(330)

Increase in restricted cash, net		(11)			(11)
Decrease in notes receivable		15			15
Purchases of emission allowances	(45)				(45)
Proceeds from sale of emission allowances	11				11
Investments in nuclear decommissioning trust fund securities	(76)				(76)
Proceeds from sales of nuclear decommissioning trust fund securities	67				67
Proceeds from renewable energy grants	84	18			102
Proceeds from sale of assets, net	1		29		30
Other		(2)	(5)		(7)
Net Cash (Used)/Provided by Investing Activities	(842)	1,441	(1,865)	881	(385)
Cash Flows from Financing Activities					
(Payments)/proceeds from intercompany loans	127	15	739	(881)	
Payment of intercompany dividends	(30)	(37)		67	
Payment of dividends to preferred stockholders			(5)		(5)
Payments for treasury stock			(50)		(50)
Net receipt from acquired derivatives that include financing elements	27				27
Installment proceeds from sale of non-controlling interest in subsidiary		50			50
Proceeds from issuance of long-term debt	3	138			141
Proceeds from issuance of term loan for funded letter of credit facility			1,300		1,300
Increase in restricted cash supporting funded letter of credit facility		(1,300)			(1,300)
Proceeds from issuance of common stock			2		2
Payment of deferred debt issuance costs	(1)	(7)	(45)		(53)
Payment of short and long-term debt		(219)	(240)		(459)
Net Cash Provided/(Used) by Financing Activities	126	(1,360)	1,701	(814)	(347)
Effect of exchange rate changes on cash and cash equivalents		(9)			(9)
Net Increase/(Decrease) in Cash and Cash Equivalents	14	34	(184)		(136)
Cash and Cash Equivalents at Beginning of Period	20	120	2,164		2,304
Cash and Cash Equivalents at End of Period	$ 34	$ 154	$ 1,980	$	$ 2,168

(a) All significant intercompany transactions have been eliminated in consolidation.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Three Months Ended June 30, 2009

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[a]	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 1,025	$ 1,254	$ 32	$ (74)	$ 2,237
Operating Costs and Expenses					
Cost of operations	596	719	1	(74)	1,242
Depreciation and amortization	157	54	2		213
Selling, general and administrative	17	51	63		131
Acquisition related transaction and integration costs			23		23
Development costs	2	3	4		9
Total operating costs and expenses	772	827	93	(74)	1,618
Operating Income/(Loss)	253	427	(61)		619
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	120		477	(597)	
Equity in earnings of unconsolidated affiliates	3	2			5
Gain on sale of equity method investment		128			128
Other income/(expense), net	2	(12)	(1)		(11)
Interest expense	(18)	(38)	(103)		(159)
Total other income/(expense)	107	80	373	(597)	(37)
Income/(Loss) Before Income Taxes	360	507	312	(597)	582
Income tax expense/(benefit)	97	174	(121)		150
Net Income	263	333	433	(597)	432
Less: Net loss attributable to noncontrolling interest	(1)				(1)
Net Income/(Loss) attributable to NRG Energy, Inc.	$ 264	$ 333	$ 433	$ (597)	$ 433

(a) All significant intercompany transactions have been eliminated in consolidation.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Six Months Ended June 30, 2009

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
Operating Revenues					
Total operating revenues	$2,591	$ 1,349	$ 32	$ (77)	$3,895
Operating Costs and Expenses					
Cost of operations	1,294	787	4	(77)	2,008
Depreciation and amortization	315	64	3		382
Selling, general and administrative	34	54	126		214
Acquisition related transaction and integration costs			35		35
Development costs	4	5	13		22
Total operating costs and expenses	1,647	910	181	(77)	2,661
Operating Income/(Loss)	944	439	(149)		1,234
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	129		874	(1,003)	
Equity in earnings of unconsolidated affiliates	4	23			27
Gain on sale of equity method investment		128			128
Other income/(expense), net	3	(19)	2		(14)
Interest expense	(66)	(59)	(172)		(297)
Total other income/(expense)	70	73	704	(1,003)	(156)
Income/(Loss) Before Income Taxes	1,014	512	555	(1,003)	1,078
Income tax expense/(benefit)	349	175	(76)		448
Net Income	665	337	631	(1,003)	630
Less: Net loss attributable to noncontrolling interest	(1)				(1)
Net Income attributable to NRG Energy, Inc.	$ 666	$ 337	$ 631	$ (1,003)	$ 631

(a) All significant intercompany transactions have been eliminated in consolidation.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2009

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
ASSETS					
Current Assets					
Cash and cash equivalents	$ 20	$ 120	$ 2,164	$	$ 2,304
Funds deposited by counterparties	177				177
Restricted cash	1	1			2
Accounts receivable-trade, net	837	39			876
Inventory	529	12			541
Derivative instruments valuation	1,636				1,636
Cash collateral paid in support of energy risk management activities	359	2			361
Prepayments and other current assets	194	61	157	(101)	311
Total current assets	3,753	235	2,321	(101)	6,208
Net Property, Plant and Equipment	10,494	1,009	61		11,564
Other Assets					
Investment in subsidiaries	613	222	16,862	(17,697)	
Equity investments in affiliates	42	367			409
Capital leases and note receivable, less current portion	4,982	504	3,027	(8,009)	504
Goodwill	1,718				1,718
Intangible assets, net	1,755	20	33	(31)	1,777
Nuclear decommissioning trust fund	367				367
Derivative instruments valuation	718		8	(43)	683
Other non-current assets	29	8	111		148
Total other assets	10,224	1,121	20,041	(25,780)	5,606
Total Assets	$ 24,471	$ 2,365	$ 22,423	$ (25,881)	$ 23,378
LIABILITIES AND STOCKHOLDERS EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 58	$ 310	$ 261	$ (58)	$ 571
Accounts payable	(852)	393	1,156		697
Derivative instruments valuation	1,469	2	2		1,473
Deferred income taxes	456	11	(270)		197
	177				177

Cash collateral received in support of energy risk management activities					
Accrued expenses and other current liabilities	261	82	347	(43)	647
Total current liabilities	1,569	798	1,496	(101)	3,762
Other Liabilities					
Long-term debt and capital leases	2,533	1,003	12,320	(8,009)	7,847
Nuclear decommissioning reserve	300				300
Nuclear decommissioning trust liability	255				255
Deferred income taxes	1,711	(165)	237		1,783
Derivative instruments valuation	323	28	79	(43)	387
Out-of-market contracts	318	7		(31)	294
Other non-current liabilities	431	16	359		806
Total non-current liabilities	5,871	889	12,995	(8,083)	11,672
Total liabilities	7,440	1,687	14,491	(8,184)	15,434
3.625% Preferred Stock			247		247
Stockholders Equity	17,031	678	7,685	(17,697)	7,697
Total Liabilities and Stockholders Equity	$24,471	$2,365	$ 22,423	$(25,881)	$ 23,378

(a) All significant intercompany transactions have been eliminated in consolidation.

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NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2009

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations[(a)]	Consolidated Balance
Cash Flows from Operating Activities					
Net income	$ 666	$ 337	$ 630	$ (1,003)	$ 630
Adjustments to reconcile net income to net cash provided by operating activities:					
Distributions and equity in (earnings)/losses of unconsolidated affiliates and consolidated subsidiaries	197	(23)	(544)	343	(27)
Depreciation and amortization	315	64	3		382
Provision for bad debts		9			9
Amortization of nuclear fuel	19				19
Amortization of financing costs and debt discount/premiums		7	14		21
Amortization of intangibles and out-of-market contracts	(49)	64			15
Changes in deferred income taxes and liability for unrecognized tax benefits	100	14	331		445
Changes in nuclear decommissioning liability	15				15
Changes in derivatives	(198)	(170)			(368)
Changes in collateral deposits supporting energy risk management activities	274	(29)			245
Gain on sale of equity method investment		(128)			(128)
Gain on sale of assets	(1)				(1)
Gain on sale of emission allowances	(9)				(9)
Gain recognized on settlement of pre-existing relationship			(31)		(31)
Amortization of unearned equity compensation			13		13
Changes in option premium collected, net of acquisition	(265)	(5)			(270)
Cash provided/(used) by changes in other working capital, net of acquisition	533	170	(941)		(238)

Net Cash Provided/(Used) by Operating Activities	1,597	310	(525)	(660)	722
Cash Flows from Investing Activities					
Intercompany (loans to)/receipts from subsidiaries	(901)		160	741	
Acquisition of Reliant Energy, net of cash acquired		(57)	(288)		(345)
Investment in Reliant Energy		200	(200)		
Capital expenditures	(263)	(109)	(2)		(374)
(Increase)/decrease in restricted cash, net	6	(9)			(3)
Decrease/(increase) in notes receivable		(47)	36		(11)
Purchases of emission allowances	(52)				(52)
Proceeds from sale of emission allowances	15				15
Investment in nuclear decommissioning trust fund securities	(172)				(172)
Proceeds from sales of nuclear decommissioning trust fund securities	157				157
Proceeds from sale of assets, net	6				6
Other investment			(5)		(5)
Proceeds from sale of equity method investment		284			284
Net Cash (Used)/Provided by Investing Activities	(1,204)	262	(299)	741	(500)
Cash Flows from Financing Activities					
(Payments)/proceeds from intercompany loans	(188)	28	901	(741)	
Payment from intercompany dividends	(330)	(330)		660	
Payment of dividends to preferred stockholders			(21)		(21)
Receipt from/(payment of) from financing element of acquired derivatives	102	(124)			(22)
Installment proceeds from sale of noncontrolling interest in subsidiary		50			50
Proceeds from issuance of long-term debt	34	98	688		820
Payment of deferred debt issuance costs	(1)	(1)	(27)		(29)
Payment of short and long-term debt		(20)	(213)		(233)

Net Cash (Used)/Provided by Financing Activities	(383)	(299)	1,328	(81)	565
Effect of exchange rate changes on cash and cash equivalents		1			1
Net Decrease in Cash and Cash Equivalent	10	274	504		788
Cash and Cash Equivalents at Beginning of Period	(2)	159	1,337		1,494
Cash and Cash Equivalents at End of Period	$ 8	$ 433	$ 1,841	$	$ 2,282

(a) All significant intercompany transactions have been eliminated in consolidation.

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

As you read this discussion and analysis, refer to the Company s Condensed Consolidated Statements of Operations to this Form 10-Q, which present the results of operations for the three and six months ended June 30, 2010, and 2009. Also refer to NRG s Annual Report on Form 10-K for the year ended December 31, 2009, which includes detailed discussions of various items impacting the Company s business, results of operations and financial condition, including: Introduction and Overview section which provides a description of NRG s business segments; Strategy section; Business Environment section, including how regulation, weather, and other factors affect NRG s business; and Critical Accounting Policies and Estimates section.

The discussion and analysis below has been organized as follows:

- Executive Summary, including introduction and overview, business strategy, and changes to the business environment during the period including regulatory and environmental matters;

- Results of operations beginning with an overview of the Company s consolidated results, followed by a more detailed discussion of those results by operating segment;

- Financial condition addressing liquidity position, sources and uses of cash, capital resources and requirements, commitments, and off-balance sheet arrangements; and

- Known trends that may affect NRG s results of operations and financial condition in the future.

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Executive Summary

Introduction and Overview

NRG Energy, Inc., or NRG or the Company, is primarily a wholesale power generation company with a significant presence in major competitive power markets in the United States, as well as a major retail electricity provider in the ERCOT (Texas) market through Reliant Energy. NRG is engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, the trading of energy, capacity and related products in the United States and select international markets, and the supply of electricity and energy services to retail electricity customers in the Texas market.

As of June 30, 2010, NRG had a total global generation portfolio of 187 active operating fossil fuel and nuclear generation units, at 44 power generation plants, with an aggregate generation capacity of approximately 23,985 MW, and approximately 255 MW under construction which includes partner interests of 125 MW. In addition to its fossil fuel plant ownership, NRG has ownership interests in operating renewable facilities with an aggregate generation capacity of 465 MW, consisting of four wind farms representing an aggregate generation capacity of 445 MW and a 20 MW solar facility. Within the United States, NRG has large and diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 22,980 MW of fossil fuel and nuclear generation capacity in 179 active generating units at 42 plants. The Company s power generation facilities are most heavily concentrated in Texas (approximately 11,440 MW, including 445 MW from four wind farms), the Northeast (approximately 6,885 MW), South Central (approximately 2,855 MW), and West (approximately 2,150 MW, including 20 MW from a solar facility) regions of the United States, with approximately 115 MW of additional generation capacity from the Company s thermal assets. In addition, through certain foreign subsidiaries, NRG has investments in power generation projects located in Australia and Germany with approximately 1,005 MW of generation capacity.

NRG s principal domestic power plants consist of a mix of natural gas-, coal-, oil-fired, nuclear and renewable facilities, representing approximately 45%, 31%, 17%, 5% and 2% of the Company s total domestic generation capacity, respectively. In addition, 9% of NRG s domestic generating facilities have dual or multiple fuel capacity, which allows those plants to dispatch with the lowest cost fuel option.

NRG s domestic generation facilities consist of intermittent, baseload, intermediate and peaking power generation facilities, the ranking of which is referred to as the Merit Order, and include thermal energy production plants. The sale of capacity and power from baseload generation facilities accounts for the majority of the Company s revenues and provides a stable source of cash flow. In addition, NRG s generation portfolio provides the Company with opportunities to capture additional revenues by selling power during periods of peak demand, offering capacity or similar products to retail electric providers and others, and providing ancillary services to support system reliability.

Reliant Energy, the Company s retail electricity provider, arranges for the transmission and delivery of electricity to customers, bills customers, collects payments for electricity sold and maintains call centers to provide customer service. Based on metered locations, as of June 30, 2010, Reliant Energy had approximately 1.5 million Mass customers and approximately 0.1 million C&I customers, with expected annual volumes for these customer classes of 20 TWhs and 25-30 TWhs, respectively.

Furthermore, NRG is focused on the development and investment in energy-related new businesses and new technologies where the benefits of such investments represent significant commercial opportunities and create a comparative advantage for the Company. These investments include low or no GHG emitting energy generating sources, such as nuclear, wind, solar thermal, photovoltaic, biomass, clean coal and gasification, the retrofit of post-combustion carbon capture technologies, and developments in the electric vehicle ecosystem.

NRG s Business Strategy

NRG s business strategy is intended to maximize shareholder value through the production and sale of safe, reliable and affordable power to its customers in the markets served by the Company, while aggressively positioning the Company to meet the market s increasing demand for sustainable and low carbon energy solutions. This dual strategy is designed to perfect the Company s core business of competitive power generation and establish the Company as a leading provider of sustainable energy solutions, while utilizing the Company s retail business to complement and advance both initiatives.

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The Company s core business is focused on: (i) top decile operating performance of its existing operating assets, (ii) optimal hedging of baseload and retail operations, while retaining optionality on the Company s gas fleet, (iii) repowering of power generation assets at existing sites and reducing environmental impacts, (iv) pursuit of selective acquisitions, joint ventures, divestitures and investments, and (v) engaging in a proactive capital allocation plan focused on achieving the regular return of capital to stockholders within the dictates of prudent balance sheet management.

In addition, the Company believes that success in providing energy solutions that address sustainability and climate change concerns will not only reduce the carbon and capital intensity of the Company in the future, it also will reduce the real and perceived linkage between the Company s financial performance and prospects, and volatile commodity prices, particularly with respect to natural gas. The Company s initiatives in this area of future growth are focused on: (i) low carbon baseload primarily nuclear generation, (ii) renewables, with a concentration in solar and wind generation and development, (iii) fast start, high efficiency gas-fired capacity in the Company s core regions, (iv) electric vehicle ecosystems, and (v) smart grid services. The Company s advancements in each of these areas are driven by select acquisitions, joint ventures, and investments that are more fully described in the Company s 2009 Annual Report on Form 10-K, the Quarterly Report on Form 10-Q for the quarter ended March 31, 2010, and this Form 10-Q.

Environmental Matters

Environmental Regulatory Landscape

A number of regulations that could significantly impact the power generation industry are in development or under review by the U.S. EPA: CAIR, MACT, NAAQS revisions, coal combustion byproducts, once-through cooling, and GHG regulations. While most of these regulations have been considered for some time, they are expected to gain clarity in 2010 through 2011. The timing and stringency of these regulations will provide a framework for the retrofit of existing fossil plants and deployment of new, cleaner technologies in the next decade. The Company has included capital to meet anticipated CAIR Phase I and II, CATR, MACT standards for mercury, and the installation of Best Technology Available under the 316(b) Rule in the current estimated environmental capital expenditure. While the Company cannot predict the impact of future regulations and would likely face additional investments over time, these expenditures, combined with the Company s already existing air quality controls, use of Powder River Basin coal, closed cycle cooling, and dry ash handling systems position NRG well to meet more stringent requirements.

The U.S. EPA released the proposed Clean Air Transport Rule, or CATR, on July 6, 2010. This rule is designed to replace CAIR and address the findings of the D.C. Court of Appeals that initially vacated the rule. It is designed to bring 31 states and D.C. into attainment with PM 2.5 and ozone national ambient air quality standards through emission reductions in SO_2 and NO_x. Proposed implementation would be through a cap and trade program starting in 2012 with constrained trading between states in the CATR regions. In 2014 the SO_2 cap would be further reduced in certain states. Under CATR, CAIR use of discounted Acid Rain SO_2 allowances would be discontinued and replaced with a completely distinct CATR SO_2 allowance program. Acid Rain allowances would still be required on a 1:1 basis under the Acid Rain Program. NRG continues to evaluate the proposed rule and any impact it has to emission markets and currently estimates that the proposed rule, if it becomes effective, could result in up to a $50 million future impairment of the Company s SO_2 emission allowance intangible assets. NRG s planned environmental capital expenditures are consistent with reductions anticipated in the rule.

The New York State Department of Environmental Conservation finalized the NO_x RACT Rule on July 14, 2010. This rule identifies new NO_x emission limits for major sources which must be met by July 1, 2014. Plants can comply or request an alternate Reasonably Available Control Technology, or RACT, limit. All of NRG s facilities are able to meet the new standards with the exception of Oswego, which will apply for an alternate limit.

On May 4, 2010, the U.S. EPA proposed two options for the regulation of coal combustion residue, commonly known as coal ash. Under the Proposal s first regulatory option, the U.S. EPA would reverse its August 1993 and May 2000 Bevill Regulatory Determinations and list coal ash as a special waste subject to regulation under hazardous waste regulations. The second regulatory option would leave the Bevill Determination in place and regulate disposal of coal ash as non-hazardous. Under both options, an exemption for the beneficial use of coal ash would remain in place. Additionally, under both options, the U.S. EPA would establish dam safety requirements to address the structural integrity of surface impoundments. While it is not possible to predict the impact of this rule until it is final, as proposed it is not expected to have a material impact on NRG s operations, as all flyash disposal sites are dry landfills; however, should the U.S. EPA implement the hazardous waste option, NRG may incur significant costs due to loss of markets for beneficial reuse. Given the recent release of this proposed rule, NRG will continue to monitor developments and their respective impact on the Company s operations.

On May 4, 2010, the California State Water Resources Control Board adopted a statewide 316(b) policy to mitigate once through cooling in California. Options for power plants with once through cooling include transitioning to a closed loop system, retirement or submitting an alternative plan that meets equivalent mitigation criteria. Specified compliance dates for NRG s El Segundo and Encina Power Plants are December 31, 2015, and December 31, 2017, respectively. NRG is analyzing compliance through a mix of alternative mitigation plans and repowering.

In June 2010, the U.S. EPA issued a Section 308 Information Collection Request to steam electric power generating plants across the industry, including 13 NRG facilities. The questionnaire focuses on water and wastewater discharges from power plants. The U.S. EPA indicated results will be used to develop new effluent guidelines for the industry.

Finalization of the Endangerment Finding, a rule addressing tailpipe limitations for light duty vehicles, and a final interpretation of the Johnson Memorandum set the stage for regulation of GHGs from stationary sources. On June 3, 2010, the U.S. EPA published the final rule tailoring the applicability criteria that determine which new and modified sources will become subject to permitting requirements for GHGs under the Prevention of Significant Deterioration, or PSD and Title V programs of the Clean Air Act. The rule raised applicability triggers to 75,000 or 100,000 tons per year CO_2 equivalents, or CO_2e, and implemented the requirements in two phases on January 2, 2011 or July 2, 2011. The immediate impact to NRG s new and modified facilities is not expected to be material; the Company will continue to evaluate the potential long-term impact as regulatory programs are implemented over time.

Climate Change Legislation

In 2009, in the course of producing approximately 71 million MWh of electricity, NRG s power plants emitted 59 million tonnes of CO_2, of which 53 million tonnes were emitted in the United States, 3 million tonnes in Germany and 3 million tonnes in Australia. During the same period, NRG emitted approximately 8 million tons of CO_2 in the RGGI region. The impact from legislation or federal, regional or state regulation of GHGs on the Company s financial performance will depend on a number of factors, including the overall level of GHG reductions required under any such regulations, the price and availability of offsets, and the extent to which NRG would be entitled to receive CO_2 emissions allowances without having to purchase them in an auction or on the open market. Thereafter, under any such legislation or regulation, the impact on NRG would depend on the Company s level of success in developing and deploying low and no carbon technologies such as those being pursued as discussed in the above.

Congress has been unable to come to an agreement on climate legislation during this session. Lack of legislation will prolong the uncertainty of the nature and timing of GHG requirements and their resulting impact on NRG.

Regulatory Matters

As operators of power plants and participants in wholesale energy markets, certain NRG entities are subject to regulation by various federal and state government agencies. These include the U.S. Commodity Futures Trading Commission, or CFTC, FERC, U.S. Nuclear Regulatory Commission, or NRC, PUCT and other public utility commissions in certain states where NRG s generating or thermal assets are located. In addition, NRG is subject to the market rules, procedures and protocols of the various ISO markets in which it participates. Certain of the Reliant Energy entities are competitive Retail Electric Providers, or REPs, and as such are subject to the rules and regulations of the PUCT governing REPs. NRG must also comply with the mandatory reliability requirements imposed by the North American Electric Reliability Corporation, or NERC, and the regional reliability councils in the regions where the Company operates. The operations of, and wholesale electric sales from, NRG s Texas region are not subject to rate regulation by the FERC, as they are deemed to operate solely within the ERCOT market and not in interstate commerce.

Financial Reform On July 21, 2010, President Obama signed the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which, among other things, aims to improve transparency and accountability in derivative markets. While the Dodd-Frank Act increases the CFTC s regulatory authority over over-the-counter derivatives, there is uncertainty on several issues related to market clearing, definitions of market participants, reporting, and capital requirements. Thus, while many details remain to be addressed in CFTC rulemaking proceedings, at this time the Company does not anticipate any material impact to its current hedging collateral strategy. NRG s view is informed by a letter dated June 30, 2010 from Senate Banking Committee Chairman Dodd and Senate Agriculture Committee Chairman Lincoln clarifying that the legislative intent of the Dodd-Frank Act is not to impose margin requirements on end users that use swaps to hedge or mitigate commercial risks.

New England On February 22, 2010, ISO-NE filed proposed amendments to its Forward Capacity Market, or FCM, design with FERC. A number of generators protested the ISO-NE filing, arguing that FERC should not accept the proposed amendments. On March 23, 2010, an association of generators filed a complaint alleging that the proposed FCM amendments are not just and reasonable due to market distortions such as out-of-market contracts, and thus would continue to under-compensate capacity suppliers in New England. On April 2, 2010, NRG and PSEG jointly filed a second complaint alleging that the existing FCM market fails to adequately establish zonal prices and thus does not adequately compensate suppliers for the locational value of their capacity. These complaints are seeking only prospective relief. Any changes to the FCM market in response to these complaints could benefit from the Company s existing New England assets in future FCM auctions. On April 23, 2010, FERC issued an order consolidating the proceedings. In its order, FERC accepted some of the ISO-NE s proposed changes, but also set several of the central issues for hearing and settlement processes.

California On May 4, 2010, the U.S. Court of Appeals for the D.C. Circuit in *Southern California Edison Company v. FERC* vacated FERC s acceptance of station power rules for the CAISO market, and remanded the case for further proceedings at FERC. As a result of the court s decision, NRG s power plants may be prevented from netting their station power consumption against their sales on a monthly basis in the California markets, which could require NRG to purchase station power at retail rates. Additionally, the precedent announced in this case may affect station power tariffs in other markets.

Changes in Accounting Standards

See Note 2, *Summary of Significant Accounting Policies*, to this Form 10-Q as found in Item 1 for a discussion of recent accounting developments.

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Consolidated Results of Operations

The following table provides selected financial information for the Company:

	Three months ended June 30,			Six months ended June 30,		
(In millions except otherwise noted)	**2010**	**2009**	**Change %**	**2010**	**2009**	**Change %**
Operating Revenues						
Energy revenue	$ 605	$ 725	(17)%	$1,283	$1,612	(20)%
Capacity revenue	206	253	(19)	417	513	(19)
Retail revenue	1,341	1,250	7	2,586	1,250	107
Risk management activities	(2)	(12)	83	89	425	(79)
Contract amortization	(52)	(53)	2	(114)	(32)	(256)
Thermal revenue	20	21	(5)	48	55	(13)
Other revenues	15	53	(72)	39	72	(46)
Total operating revenues	2,133	2,237	(5)	4,348	3,895	12
Operating Costs and Expenses						
Cost of sales	1,129	1,175	(4)	2,318	1,628	42
Risk management activities	(84)	(204)	59	51	(136)	138
Other cost of operations	284	271	5	599	516	16
Total cost of operations	1,329	1,242	7	2,968	2,008	48
Depreciation and amortization	208	213	(2)	410	382	7
Selling, general and administrative	139	131	6	269	214	26
Acquisition-related transaction and integration costs		23	(100)		35	(100)
Development costs	13	9	44	22	22	
Total operating costs and expenses	1,689	1,618	4	3,669	2,661	38
Gain on sale of assets				23		
Operating income	444	619	(28)	702	1,234	(43)
Other Income/(Expense)						
Equity in earnings of unconsolidated affiliates	11	5	120	25	27	(7)
Gain on sale of equity method investments		128	(100)		128	(100)
Other income/(expense), net	19	(11)	273	23	(14)	264
Interest expense	(147)	(159)	(8)	(300)	(297)	1
Total other expense	(117)	(37)	216	(252)	(156)	62
Income before income tax expense	327	582	(44)	450	1,078	(58)
Income tax expense	117	150	(22)	182	448	(59)
Net Income	210	432	(51)	268	630	(57)

Less: Net loss attributable to noncontrolling interest	(1)	(1)		(1)	(1)	
Net income attributable to NRG Energy, Inc.	$ 211	$ 433	(51)	$ 269	$ 631	(57)
Business Metrics						
Average natural gas price Henry Hub ($/MMBtu)	4.09	3.68	11%	4.69	4.13	14%

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Management s discussion of the results of operations for the three months ended June 30, 2010, and 2009:

The table below represents the results of NRG excluding the impact of Reliant Energy, and adjusted for intercompany transactions between Reliant Energy and the Texas region, during the three months ended June 30, 2010, and 2009:

	2010				2009			
(In millions)	Consolidated	Reliant Energy	Eliminations	Total excluding Reliant Energy	Consolidated	Reliant Energy[(a]	Eliminations	Total excluding Reliant Energy
Operating Revenues								
Energy revenue	$ 605	$	$ 284	$ 889	$ 725	$	$ 54	$ 779
Capacity revenue	206		3	209	253		11	264
Retail revenue	1,341	1,341			1,250	1,250		
Risk management activities	(2)		(19)	(21)	(12)		2	(10)
Contract amortization	(52)	(59)		7	(53)	(75)		22
Thermal revenue	20			20	21			21
Other revenues	15		13	28	53		2	55
Total operating revenues	2,133	1,282	281	1,132	2,237	1,175	69	1,131
Operating Costs and Expenses								
Cost of sales	1,129	937	300	492	1,175	803	71	443
Risk management activities	(84)	(76)	(19)	(27)	(204)	(189)	(2)	(17)
Other operating costs	284	49		235	271	41		230
Total cost of operations	1,329	910	281	700	1,242	655	69	656
Depreciation and amortization	208	29		179	213	43		170
Selling, general and administrative	139	64		75	131	49		82
Acquisition-related transaction and integration costs					23			23
Development costs	13			13	9			9
Total operating costs and expenses	1,689	1,003	281	967	1,618	747	69	940
Operating income	$ 444	$ 279	$	$ 165	$ 619	$ 428	$	$ 191

(a) *Reliant Energy results are for the period May 1, 2009, to June 30, 2009.*

Operating Revenues

Operating revenues, excluding risk management activities, decreased by $114 million during the three months ended June 30, 2010, compared to the same period in 2009.

Retail revenue increased by $91 million. This increase was driven by $354 million of revenue for the month of April included in 2010, which was offset by a decrease of $263 million from Mass, C&I and supply management revenues during the two month period ended June 30 2010, as compared to 2009. Mass revenues decreased by $143 million due to 12% lower revenue rates and 8% lower volumes due to fewer customers. C&I revenues decreased by $86 million due to 17% lower volumes driven by fewer customers.

Energy revenue including intercompany revenue, increased $110 million during the three months ended June 30, 2010, compared to the same period in 2009:

- *Texas* increased by $64 million with $66 million increase driven by higher energy prices and an increase in margin on megawatt hours sold from market purchases of $12 million, offset by a $13 million decrease driven by reduction in generation. The average realized energy price increased by 11%, driven by a 14% increase in merchant prices and a 3% increase in contract prices. Intercompany sales to Reliant Energy, which eliminate in consolidation, were $284 million, an increase of $230 million over the two month period in 2009. Generation decreased by 2%, driven by an 18% decrease in nuclear plant generation and a 6% decrease in gas plant generation. The decrease in nuclear plant generation is due to an STP Unit 2 spring refueling outage in 2010. These decreases were offset by an increase in wind farm generation as Langford began commercial operation in December 2009.

- o *Northeast* increased by $36 million, with $32 million driven by higher energy prices and $4 million driven by 3% higher generation. Merchant energy prices were higher by an average of 50%. The increase in oil and gas generation is attributable to higher reliability run hours at the Connecticut plants.

- o *South Central* increased by $15 million due to a $19 million increase in contract revenue offset by a decrease of $4 million in merchant energy revenues. The increase in contract energy price was driven by a $6 million increase in fuel cost pass-through from the cooperatives and a $12 million increase due to a new contract with a regional municipality. Total megawatt hour sales to the region s contract customers were up 13% while the average realized price on contract energy sales was $27.77 per MWh in 2010 compared to $22.98 per MWh in 2009. Megawatt hours sold to the merchant market increased by 26% but lower realized merchant prices resulted in a decrease of $4 million.

Capacity revenue including intercompany revenue, decreased $55 million during the three months ended June 30, 2010, compared to the same period in 2009:

- o *Texas* decreased by $42 million resulting from a lower proportion of baseload contracts which contain a capacity component. Intercompany sales to Reliant Energy, which eliminate in consolidation, decreased by $8 million.

- o *South Central* decreased by $7 million primarily due to expiration of a capacity agreement with a regional utility.

Contract amortization revenue decreased by $1 million during the three months ended June 30, 2010, as compared to the same period in 2009. The contract amortization expense decreased by $16 million at Reliant Energy offset by a $15 million reduction in contract amortization revenue in the Texas region due to the lower volume of contracted energy.

Other revenues decreased by $38 million during the three months ended June 30, 2010, as compared to the same period in 2009, driven by $7 million in lower emissions revenues and a $31 million non-cash gain related to the settlement of pre-existing in-the-money contracts with Reliant Energy recognized in 2009. The Texas region s intercompany ancillary sales to Reliant Energy, which eliminate in consolidation, were $13 million, an increase of $12 million over the two month period in 2009.

Cost of Operations

Cost of operations, excluding risk management activities, decreased by $33 million during the three months ended June 30, 2010, compared to the same period in 2009.

Cost of sales including intercompany purchases, decreased $46 million during the three months ended June 30, 2010, compared to the same period in 2009 due to:

- o *Retail* increased by $134 million, with $280 million of costs for the month of April included in 2010. This increase was offset by a $151 million decrease in supply costs and by a $26 million decrease in transmission and distribution charges for the two month period ended June 30, 2010, as compared to 2009. Intercompany purchases from the Texas region, which eliminate in consolidation, were $300 million, an increase of $229 million over the two month period in 2009.

- o *Texas* increased $25 million due to higher coal costs and ancillary services costs offset by a decrease in natural gas costs and purchased energy. Coal costs increased $23 million due to higher transportation charges.

- o *Northeast* increased $24 million driven by a $13 million increase in natural gas and oil costs, an $8 million increase in purchased energy and a $4 million increase in coal costs. Natural gas and oil costs increased due to 20% higher generation and 37% higher average natural gas prices. Purchased energy increased due to costs to supply new load contracts which commenced on June 1, 2010. Coal costs increased due to 52% higher average prices offset by 1% lower coal generation.

Other costs of operations increased $13 million during the three months ended June 30, 2010, compared to the same period in 2009. Maintenance expenses in the Texas and South Central regions increased by

$24 million due to planned baseload outages which was offset by a decrease of $16 million in the Northeast region due to lower property tax expense and lower operations and maintenance expenses.

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Risk Management Activities

Risk management activities include economic hedges that did not qualify for cash flow hedge accounting, ineffectiveness on cash flow hedges, and trading activities. Total derivative gains decreased by $110 million during the three months ended June 30, 2010, compared to the same period in 2009. The breakdown of changes by region are as follows:

	Three months ended June 30, 2010							
	Reliant Energy	Texas	Northeast	South Central	West	Thermal	Elimination	Total
	(In millions)							
Net gains/(losses) on settled positions	$ (88)	$ 69	$ 44	$ (8)	$1	$ 2	$	$20
Mark-to-market gains/(losses)	163	(57)	(55)	10	2	(1)		62
Total derivative gains/(losses) included in revenues and cost of operations	$ 75	$ 12	$(11)	$ 2	$3	$ 1	$	$82

	Three months ended June 30, 2009							
	Reliant Energy[(a)]	Texas	Northeast	South Central	West	Thermal	Elimination	Total
	(In millions)							
Net gains/(losses) on settled positions	$(114)	$ 101	$ 95	$ (5)	$(1)	$ 1	$	$ 77
Mark-to-market gains/(losses)	303	(144)	(34)	(15)	7	(2)		115
Total derivative gains/(losses) included in revenues and cost of operations	$ 189	$ (43)	$ 61	$(20)	$ 6	$(1)	$	$192

(a) *Reliant Energy results are for the period May 1, 2009, to June 30, 2009.*

The breakdown of gains and losses included in revenue and cost of operations by region are as follows:

	Three months ended June 30, 2010							
	Reliant Energy	Texas	Northeast	South Central	West	Thermal	Elimination[(a)]	Total

		(In millions)						
Net gains/(losses) on settled positions, or financial income in revenues	$	$ 70	$ 44	$(8)	$1	$ 2	$ (28)	$ 81
Mark-to-market results in revenues								
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges		(16)	(34)	1		(1)	2	(48)
Reversal of previously recognized unrealized losses on settled positions related to trading activity		7		1				8
Net unrealized (losses)/gains on open positions related to economic hedges		(66)	(28)	(4)	1		45	(52)
Net unrealized gains on open positions related to trading activity		2	3	3	1			9
Subtotal mark-to-market results		(73)	(59)	1	2	(1)	47	(83)
Total derivative (losses)/gains included in revenues	$	$ (3)	$(15)	$(7)	$3	$ 1	$ 19	$ (2)

(a) Represents the elimination of $19 million intercompany loss in the Texas region. The offsetting intercompany gain is included in cost of operations in the Reliant Energy region.

	Three months ended June 30, 2009							
	Reliant Energy[(a)]	Texas	Northeast	South Central	West	Thermal	Elimination[(b)]	Total
				(In millions)				
Net gains/(losses) on settled positions, or financial income in revenues	$	$ 105	$ 96	$ (2)	$(1)	$ 1	$	$ 199
Mark-to-market results in revenues								
Reversal of previously recognized unrealized gains on settled positions related to economic hedges		(16)	(32)			(1)		(49)
Reversal of previously recognized unrealized gains on settled positions related to trading activity		(14)	(9)	(12)				(35)
Net unrealized (losses)/gains on open positions related to economic hedges		(119)	(9)	(4)	7	(1)	(2)	(128)
Net unrealized (losses)/gains on open positions related to trading activity		(10)	5	6				1
Subtotal mark-to-market results		(159)	(45)	(10)	7	(2)	(2)	(211)
Total derivative (losses)/gains included in revenues	$	$ (54)	$ 51	$(12)	$ 6	$(1)	$ (2)	$ (12)

(a) Reliant Energy results are for the period May 1, 2009, to June 30, 2009.

(b) Represents the elimination of $2 million intercompany gain in the Texas region. The offsetting intercompany

loss is included in cost of operations in the Reliant Energy region.

	Three months ended June 30, 2010					
	Reliant Energy	Texas	Northeast	South Central	Elimination[a]	Total
	(In millions)					
Net (losses)/gains on settled positions, or financial expense in cost of operations	$ (88)	$ (1)	$	$	$ 28	$ (61)
Mark-to-market results in cost of operations						
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	(17)	8	4	4	(2)	(3)
Reversal of loss positions acquired as part of the Reliant Energy acquisition as of May 1, 2009	60					60
Net unrealized gains/(losses) on open positions related to economic hedges	120	8		5	(45)	88
Subtotal mark-to-market results	163	16	4	9	(47)	145
Total derivative gains/(losses) included in cost of operations	$ 75	$15	$ 4	$9	$ (19)	$ 84

(a) *Represents the elimination of $19 million intercompany gains in the Reliant Energy region. The offsetting intercompany loss is included in revenue in the Texas region.*

	Three months ended June 30, 2009					
	Reliant Energy[a]	Texas	Northeast	South Central	Elimination[b]	Total
	(In millions)					
Net losses on settled positions, or financial expense in cost of operations	$(114)	$ (4)	$ (1)	$(3)	$	$(122)
Mark-to-market results in cost of operations						
Reversal of previously recognized unrealized losses on settled positions related to economic hedges		12	19			31

Reversal of loss positions acquired as part of the Reliant Energy acquisition as of May 1, 2009	210					210
Net unrealized gains/(losses) on open positions related to economic hedges	93	3	(8)	(5)	2	85
Subtotal mark-to-market results	303	15	11	(5)	2	326
Total derivative gains/(losses) included in cost of operations	$ 189	$ 11	$ 10	$ (8)	$ 2	$ 204

(a) Reliant Energy results are for the period May 1, 2009, to June 30, 2009.

(b) Represents the elimination of $2 million intercompany loss in the Reliant Energy region. The offsetting intercompany gain is included in revenue in the Texas region.

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For the three months ended June 30, 2010, the $52 million loss in revenue from economic hedge positions is primarily driven by a decrease in value of forward sales of natural gas and electricity due to an increase in forward power and gas prices. The $88 million gain in cost of energy from economic hedge positions is primarily driven by an increase in value of forward purchases of natural gas, electricity and fuel due to an increase in forward power and gas prices. Reliant Energy s $60 million gain from the roll-off of acquired derivatives consists of loss positions that were acquired as of May 1, 2009, and valued using forward prices on that date. The roll-off amounts were offset by realized losses at the settled prices and higher costs of physical power which are reflected in cost of operations during the same period.

For the period ended June 30, 2009, the $128 million mark-to-market loss in revenue related to a decrease in value in forward sales of electricity and fuel relating to economic hedges due to an increase in forward power and gas prices. The $85 million mark-to-market gain in expense related to economic hedges was due to an increase in forward purchases of electricity and natural gas relating to retail supply, due to an increase in forward power and gas prices.

In accordance with ASC 815, the following table represents the results of the Company s financial and physical trading of energy commodities for the three months ended June 30, 2010, and 2009. The realized financial trading results and unrealized financial and physical trading results are included in the risk management activities above, while the realized physical trading results are included in energy revenue. The Company s trading activities are subject to limits within the Company s Risk Management Policy.

	Three months ended June 30,	
(In millions)	**2010**	**2009**
Trading gains/(losses)		
Realized	$(13)	$ 26
Unrealized	17	(34)
Total trading gains/(losses)	$ 4	$ (8)

Depreciation and Amortization

NRG s depreciation and amortization expense decreased by $5 million for the three months ended June 30, 2010, compared to the same period in 2009. Depreciation and amortization expense for Reliant Energy decreased by $14 million mainly due to reduction in amortization of customer relationships. This decrease was offset by a $9 million increase in depreciation related to baghouse projects in western New York, Cedar Bayou 4 project which began operations in June 2009 and Langford which began commercial operations in December 2009.

Selling, General and Administrative Expenses

Selling, general and administrative expenses increased by $8 million during the three months ended June 30, 2010, compared to the same period in 2009. The increase was due to:

Retail selling, general and administrative expense increased by $15 million due to inclusion of month of April in 2010.

This increase was offset by:

Consultant costs decreased due to $5 million non-recurring costs related to Exelon s exchange offer and proxy contest efforts incurred in 2009.

Acquisition-related Transaction and Integration Costs

NRG incurred Reliant Energy acquisition-related transaction and integration costs of $23 million for the three months ended June 30, 2009. These integration efforts were completed by the end of 2009.

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Equity in Earnings of Unconsolidated Affiliates

NRG s equity earnings from unconsolidated affiliates increased by $6 million during the three months ended June 30, 2010, compared to the same period in 2009, primarily from an increase in equity earnings from Sherbino.

Gain on Sale of Equity Method Investments

NRG s gain on sale of equity method investments in 2009 represents a $128 million gain on the sale of NRG s 50% ownership interest in MIBRAG.

Other Income/(Expense), Net

NRG s other income/(expense), net increased $30 million during the three months ended June 30, 2010, compared to the same period in 2009. The 2010 amount includes $3 million and $9 million of unrealized and realized foreign exchange gains, respectively. The 2009 amount includes a $15 million loss on a forward contract for foreign currency executed to hedge the MIBRAG sale proceeds.

Interest Expense

NRG s interest expense decreased by $12 million during the three months ended June 30, 2010, compared to the same period in 2009. This decrease was due to $7 million related to the settlement of the CSF Debt in 2009 and early 2010, a $12 million decrease in fees on the CSRA facility, a $4 million decrease due to a lower outstanding principal balance on the Term Loan Facility, and $2 million due to lower interest rates related to the unhedged portion of the Term Loan. These decreases were offset by a $10 million increase in interest expense related to the issuance of the 2019 Senior Notes in June 2009.

Income Tax Expense

NRG s income tax expense decreased by $33 million during the three months ended June 30, 2010, compared to the same period in 2009. The decrease in income tax expense was primarily due to a decrease in income. The effective tax rate was 35.8% and 25.8% for the three months ended June 30, 2010, and 2009, respectively.

For the three months ended June 30, 2010, NRG s overall effective tax rate was different than the statutory rate of 35% primarily due to state and local income taxes as well as recording federal and state tax expense and interest for unrecognized tax benefits. For the three months ended June 30, 2009, NRG s effective tax rate was different than the statutory rate of 35% primarily due to a net state and local income tax benefit as a result of the Reliant Energy acquisition, and the sale of the MIBRAG facility.

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Management s discussion of the results of operations for the six months ended June 30, 2010, and 2009:

The table below represents the results of NRG excluding the impact of Reliant Energy, and adjusted for intercompany transactions between Reliant Energy and the Texas region, during the six months ended June 30, 2010 and 2009:

	2010				2009			
(In millions)	Consolidated	Reliant Energy	Eliminations	Total excluding Reliant Energy	Consolidated	Reliant Energy(a)	Eliminations	Total excluding Reliant Energy
Operating Revenues								
Energy revenue	$1,283	$	$ 484	$ 1,767	$1,612	$	$ 54	$ 1,666
Capacity revenue	417		7	424	513		11	524
Retail revenue	2,586	2,586			1,250	1,250		
Risk management activities	89		125	214	425		2	427
Contract amortization	(114)	(128)		14	(32)	(75)		43
Thermal revenue	48			48	55			55
Other revenues	39		26	65	72		2	74
Total operating revenues	4,348	2,458	642	2,532	3,895	1,175	69	2,789
Operating Costs and Expenses								
Cost of sales	2,318	1,843	516	991	1,628	803	71	896
Risk management activities	51	248	125	(72)	(136)	(189)	(2)	51
Other operating costs	599	94	1	506	516	41		475
Total cost of operations	2,968	2,185	642	1,425	2,008	655	69	1,422
Depreciation and amortization	410	59		351	382	43		339
Selling, general and administrative	269	122		147	214	49		165
Acquisition-related transaction and integration costs					35			35
Development costs	22			22	22			22
Total operating costs and expenses	3,669	2,366	642	1,945	2,661	747	69	1,983
Gain on sale of assets	23			23				

Operating income	$ 702	$ 92	$	$ 610	$1,234	$ 428	$	$ 806

(a) Reliant Energy results are for the period May 1, 2009, to June 30, 2009.

Operating Revenues

Operating revenues, excluding risk management activities, increased $789 million during the six months ended June 30, 2010, compared to the same period in 2009.

Retail revenue for the six months ended June 30, 2010, were $2.6 billion consisting of $1.5 billion in Mass revenues and $991 million in C&I revenues. Retail revenues for the two months ended 2009 were $1.3 billion consisting of $761 million in Mass revenues and $437 million in C&I revenues.

- *Texas* increased by $98 million, with $56 million driven by higher energy prices, $10 million driven by margin on megawatt hours sold from market purchases and $31 million driven by an increase in generation. The average realized energy price increased by 5%, driven by a 1% increase in merchant prices and a 3% increase in contract prices. Intercompany sales to Reliant Energy, which eliminate in consolidation, were $484 million, an increase of $430 million over the two month period in 2009. Generation increased by 3%, driven by a 17% increase in gas plant generation and an increase in wind farm generation. Wind farm generation increased due to Langford, which began commercial operations in December 2009, and leased wind farm generation, which increased due to four additional months included in 2010. These increases were offset by a 13% decrease in nuclear plant generation due to planned outages.

- o *Northeast* decreased by $24 million, with $7 million driven by lower energy prices, $13 million driven by a reduction in generation, and $12 million of margin on a load contract which expired in May 2009, offset by an $8 million increase driven by new load-serving contracts, which commenced June 1, 2010. Merchant energy prices were lower by an average of 4%. Generation decreased by 5%, with a 19% decrease in oil and gas generation and a 2% decrease in coal generation. The decline in oil and gas generation is attributable to both planned and forced outages at Arthur Kill, Middletown and Oswego in 2010, offset by an increase due to higher reliability run hours at the Connecticut plants.

- o *South Central* increased by $25 million due to a $31 million increase in contract revenue offset by a $6 million decrease in merchant energy revenues. Of the $31 million increase, $18 million is attributable to the region s cooperative customers. Also contributing to the increase in contract revenue was $12 million due to a new contract with a regional municipality. Average realized price on contract energy sales was down $1.75 per MWh in 2010 compared to 2009. Megawatt hours sold to the merchant market decreased by 5%.

Capacity revenue including intercompany revenue, decreased $100 million during the six months ended June 30, 2010, compared to the same period in 2009:

- o *Texas* decreased by $82 million due to a lower proportion of baseload contracts which contain a capacity component. Intercompany sales to Reliant Energy, which eliminate in consolidation, decreased by $4 million.

- o *Northeast* increased by $8 million, due to a $21 million increase in capacity revenue in the NYISO and PJM markets driven by higher prices offset by a $13 million decrease in NEPOOL capacity driven by the expiration of RMR contracts for Montville, Middletown and Norwalk in 2010.

- o *South Central* decreased by $18 million due to the expiration of a capacity agreement with a regional utility.

- o *West* decreased by $7 million due to reduced resource adequacy and call option contract sales at El Segundo in 2010 compared to 2009.

Contract amortization revenue decreased by $82 million during the six months ended June 30, 2010, as compared to the same period in 2009. The decrease includes $52 million of amortization revenue for net in-market C&I contracts related to the Reliant Energy acquisition in May 2009 and a reduction of $28 million in amortization revenue in the Texas region due to the lower volume of contracted energy.

Other revenues decreased by $33 million during the six months ended June 30, 2010, as compared to the same period in 2009. The decrease was driven by $14 million in lower emissions revenues in 2010 and a $31 million non-cash gain related to the settlement of pre-existing in-the-money contracts with Reliant Energy recognized in 2009. These decreases were offset by a $9 million increase in ancillary revenue. The Texas region s intercompany ancillary sales to Reliant Energy, which eliminate in consolidation, were $25 million, an increase of $24 million over the two month period in 2009.

Cost of Operations

Cost of operations, excluding risk management activities, increased $773 million during the six months ended June 30, 2010, compared to the same period in 2009.

Cost of sales including intercompany purchases, increased $690 million during the six months ended June 30, 2010, compared to the same period in 2009 due to:

- o *Retail* Cost of energy for the six months ended June 30, 2010, was $1.8 billion consisting of $1.2 billion in supply costs and $634 million in transmission and distribution charges. Cost of energy for the two months ended June 30, 2009 was $803 million consisting of $550 million in supply costs and $267 million in transmission and distribution charges. Intercompany purchases from the Texas region, which eliminate in consolidation, were $516 million, an increase of $445 million over the two month period in 2009.

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- *Texas* increased $98 million due to higher coal and natural gas costs, ancillary services costs and purchased energy. Coal costs increased by $40 million due to a $30 million increase in transportation cost, and a $15 million due to higher prices offset by a $9 million decrease due to reduced generation. Natural gas costs increased $22 million, reflecting a 23% increase in average natural gas per MMBtu prices and a 17% increase in gas-fired generation. Ancillary service costs increased by $18 million due to an increase in purchased ancillary costs incurred to meet contract obligations. Purchased energy increased by $14 million due to a higher average price and a greater number of megawatt hours purchased to meet obligations when baseload plants are not available.

- *South Central* increased by $10 million due to an $11 million increase in purchased energy offset by $4 million decrease in coal costs due to a 1% reduction in coal generation.

Other costs of operations increased $83 million during the six months ended June 30, 2010, compared to the same period in 2009. Other costs of operations for Reliant Energy increased by $53 million due to the additional four months included in 2010. Also, maintenance expenses in the Texas and South Central regions increased by $42 million due to planned baseload outages offset by a $17 million decrease in the Northeast region mainly due to lower spending at the Indian River and Arthur Kill plants, which completed a major outage project in the second quarter of 2009.

Risk Management Activities

Risk management activities include economic hedges that did not qualify for cash flow hedge accounting, ineffectiveness on cash flow hedges, and trading activities. Total derivative gains decreased by $523 million during the six months ended June 30, 2010, compared to the same period in 2009. The breakdown of changes by region follows:

	Six months ended June 30, 2010							
	Reliant Energy	Texas	Northeast	South Central	West	Thermal	Elimination	Total
	(In millions)							
Net (losses)/gains on settled positions	$(123)	$ 77	$ 77	$(21)	$1	$ 3	$	$14
Mark-to-market (losses)/gains	(125)	170	(30)	8	3	(2)		24
Total derivative (losses)/gains included in revenues and cost of operations	$(248)	$247	$ 47	$(13)	$4	$ 1	$	$38

	Six months ended June 30, 2009							
	Reliant Energy[(a)]	Texas	Northeast	South Central	West	Thermal	Elimination	Total
	(In millions)							
Net (losses)/gains on settled positions	$(114)	$130	$151	$ 5	$(3)	$ 2	$	$171
Mark-to-market gains/(losses)	303	25	97	(40)	6	(1)		390
Total derivative gains/(losses)	$ 189	$155	$248	$(35)	$ 3	$ 1	$	$561

included in revenues and cost of operations

(a) Reliant Energy results are for the period May 1, 2009, to June 30, 2009.

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The breakdown of gains and losses included in revenue and cost of operations by region are as follows:

	Six months ended June 30, 2010							
	Reliant Energy	Texas	Northeast	South Central	West	Thermal	Elimination[(a)]	Total
	(In millions)							
Net gains/(losses) on settled positions, or financial income in revenues	$	$ 79	$ 77	$(20)	$1	$ 3	$ (37)	$ 103
Mark-to-market results in revenues								
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges		(53)	(58)	1		(2)	(9)	(121)
Reversal of previously recognized unrealized losses on settled positions related to trading activity		20	3	3				26
Net unrealized gains/(losses) on open positions related to economic hedges		156	2	(22)	1		(79)	58
Net unrealized gains on open positions related to trading activity		7	8	6	2			23
Subtotal mark-to-market results		130	(45)	(12)	3	(2)	(88)	(14)
Total derivative gains/(losses) included in revenues	$	$209	$ 32	$(32)	$4	$ 1	$ (125)	$ 89

(a) Represents the elimination of $125 million intercompany gain in the Texas region.

The offsetting intercompany loss is included in cost of operations in the Reliant Energy region.

	Six months ended June 30, 2009							
	Reliant Energy[(a)]	Texas	Northeast	South Central	West	Thermal	Elimination[(b)]	Total
	(In millions)							
Net gains/(losses) on settled positions, or financial income in revenues	$	$143	$156	$ 11	$(3)	$ 2	$	$ 309
Mark-to-market results in revenues								
Reversal of previously recognized unrealized gains on settled positions related to economic hedges		(37)	(63)			(2)		(102)
Reversal of previously recognized unrealized gains on settled positions related to trading activity		(43)	(23)	(38)				(104)
Net unrealized gains/(losses) on open positions related to economic hedges		154	159	(4)	6	1	(2)	314
Net unrealized gains/(losses) on open positions related to trading activity		(8)	4	12				8
Subtotal mark-to-market results		66	77	(30)	6	(1)	(2)	116
Total derivative gains/(losses) included in revenues	$	$209	$233	$(19)	$ 3	$ 1	$ (2)	$ 425

(a) *Reliant Energy results are for the period*

May 1, 2009, to June 30, 2009.

(b) *Represents the elimination of $2 million intercompany gain in the Texas region. The offsetting intercompany loss is included in cost of operations in the Reliant Energy region.*

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	Six months ended June 30, 2010					
	Reliant Energy	Texas	Northeast	South Central	Elimination[a]	Total
	(In millions)					
Net gains/(losses) on settled positions, or financial expense in cost of operations	$(123)	$ (2)	$	$ (1)	$ 37	$ (89)
Mark-to-market results in cost of operations						
Reversal of previously recognized unrealized (gains)/losses on settled positions related to economic hedges	(20)	23	9	9	9	30
Reversal of loss positions acquired as part of the Reliant Energy acquisition as of May 1, 2009	150					150
Net unrealized gains/(losses) on open positions related to economic hedges	(255)	17	6	11	79	(142)
Subtotal mark-to-market results	(125)	40	15	20	88	38
Total derivative (losses)/gains included in cost of operations	$(248)	$38	$ 15	$19	$ 125	$ (51)

(a) Represents the elimination of $125 million intercompany loss in the Reliant Energy region. The offsetting intercompany gain is included in revenue in the Texas region.

	Six months ended June 30, 2009					
	Reliant Energy[a]	Texas	Northeast	South Central	Elimination[b]	Total
	(In millions)					
	$(114)	$(13)	$ (5)	$ (6)	$	$(138)

Net losses on settled positions, or financial expense in cost of operations						
Mark-to-market results in cost of operations						
Reversal of previously recognized unrealized losses on settled positions related to economic hedges		25	43			68
Reversal of loss positions acquired as part of the Reliant Energy acquisition as of May 1, 2009	210					210
Net unrealized gains/(losses) on open positions related to economic hedges	93	(66)	(23)	(10)	2	(4)
Subtotal mark-to-market results	303	(41)	20	(10)	2	274
Total derivative gains/(losses) included in cost of operations	$ 189	$(54)	$ 15	$(16)	$ 2	$ 136

(a) *Reliant Energy results are for the period May 1, 2009, to June 30, 2009.*

(b) *Represents the elimination of $2 million intercompany loss in the Reliant Energy region. The offsetting intercompany gain is included in revenue in the Texas region.*

For the six months ended June 30, 2010, the $58 million gain in revenue from economic hedge positions is primarily driven by an increase in value of forward sales of natural gas and electricity due to a decrease in forward power and gas prices. The $142 million loss in cost of energy from economic hedge positions is primarily driven by a decrease in value of forward purchases of natural gas, electricity and fuel due to a decrease in forward power and gas prices. Reliant Energy s $150 million gain from the roll-off of acquired derivatives consists of loss positions that were acquired as of May 1, 2009, and valued using forward prices on that date. The roll-off amounts were offset by realized losses at the settled prices and higher costs of physical power which are reflected in cost of operations during the same period.

In accordance with ASC 815, the following table represents the results of the Company s financial and physical trading of energy commodities for the six months ended June 30, 2010, and 2009. The realized financial trading results and unrealized financial and physical trading results are included in the risk management activities above, while the realized physical trading results are included in energy revenue. The Company s trading activities are subject to limits within the Company s Risk Management Policy.

	Six months ended June 30,	
(In millions)	**2010**	**2009**
Trading gains/(losses)		
Realized	$(24)	$ 96
Unrealized	49	(96)
Total trading gains/(losses)	$ 25	$

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Depreciation and Amortization

NRG s depreciation and amortization expense increased by $28 million during the six months ended June 30, 2010, compared to the same period in 2009. Reliant Energy s depreciation and amortization expense for the six month period increased by $16 million due to the inclusion of four additional months in 2010. The balance of the increase was due to depreciation on the baghouse projects in western New York, Cedar Bayou 4, which began commercial operation in June 2009, and Langford, which began commercial operation in December 2009.

Selling, General and Administrative Expenses

Selling, general and administrative expenses increased by $55 million during the six months ended June 30, 2010, compared to the same period in 2009. The increase was due to:

- *Retail selling, general and administrative expense* increased by $73 million due to the inclusion of four additional months in 2010.

These increases were offset by

- *Labor costs* decreased by $15 million offset by higher contractor expense of $5 million.

- *Consultant costs* decreased by $9 million due to non-recurring costs related to Exelon s exchange offer and proxy contest efforts incurred in 2009.

Acquisition-related Transaction and Integration Costs

NRG incurred Reliant Energy acquisition-related transaction and integration costs of $35 million for 2009.

Gain on Sale of Assets

On January 11, 2010, NRG sold Padoma to Enel, recognizing a gain on sale of $23 million.

Equity in Earnings of Unconsolidated Affiliates

NRG s equity earnings from unconsolidated affiliates decreased by $2 million during the six months ended June 30, 2010, compared to the same period in 2009. In 2009, NRG recognized $15 million from MIBRAG, which was sold in June 2009. This decrease was partially offset by a $13 million increase from Sherbino in 2010.

Gain on Sale of Equity Method Investments

NRG s gain on sale of equity method investments in 2009 represents a $128 million gain on the sale of NRG s 50% ownership interest in MIBRAG.

Other Income/(Expense), Net

NRG s other income/(expense), net increased $37 million during the six months ended June 30, 2010, compared to the same period in 2009. The 2010 amount includes $3 million and $9 million of unrealized and realized foreign exchange gains, respectively. The 2009 amount includes a $24 million loss on a forward contract for foreign currency executed to hedge the MIBRAG sale proceeds.

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Interest Expense

NRG s interest expense increased $3 million during the six months ended June 30, 2010, compared to the same period in 2009. This increase was due to $25 million related to the issuance of the 2019 Senior Notes in June 2009. This increase was offset by a $14 million decrease due to the settlement of the CSF Debt in 2009 and early 2010 and a $7 million decrease due to a lower outstanding principal balance on the Term Loan Facility and a $2 million decrease due to lower interest rates related to the unhedged portion of the Term Loan.

Income Tax Expense

NRG s income tax expense decreased by $266 million during the six months ended June 30, 2010, compared to the same period in 2009. The decrease in income tax expense was primarily due to a decrease in income. The effective tax rate was 40.4% and 41.5% for the six months ended June 30, 2010, and 2009, respectively.

For the six months ended June 30, 2010, NRG s overall effective tax rate was different than the statutory rate of 35% primarily due to state and local income taxes as well as recording federal and state tax expense and interest for unrecognized tax benefits. For the six months ended June 30, 2009, NRG s overall effective tax rate was different than the statutory rate of 35% primarily due to an increase in valuation allowance as a result of capital losses generated in the six month period for which there are no projected capital gains or available tax planning strategies. Furthermore, the effective tax rate is decreased by the sale of the MIBRAG facility as well as a net state and local income tax benefit as a result of the Reliant Energy acquisition.

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Results of Operations Regional Discussions

The following is a detailed discussion of the results of operations of NRG s retail business segment.

Reliant Energy

Quarterly Results

For a discussion of the business profile of the Company s Reliant Energy operations, see pages 94-96 of NRG Energy, Inc. s 2009 Annual Report on Form 10-K.

Selected Income Statement Data

(In millions except otherwise noted)	Three months ended June 30, 2010	One month ended April 30, 2010	Two months ended June 30, 2010	Two months ended June 30, 2009[(c)]	Change %
Operating Revenues					
Mass revenues	$ 808	$ 190	$ 618	$ 761	(19)%
Commercial and Industrial revenues	502	151	351	437	(20)
Supply management revenues	31	13	18	52	(65)
Contract amortization	(59)	(22)	(37)	(75)	51
Total operating revenues	1,282	332	950	1,175	(19)
Operating Costs and Expenses					
Cost of energy (including risk management activities)	861	239	622	614	1
Other operating expenses	113	37	76	90	(16)
Depreciation and amortization	29	9	20	43	(53)
Operating Income	$ 279	$ 47	$ 232	$ 428	(46)
Electricity sales volume GWh					
Mass	5,732	1,275	4,457	4,851	(8)
Commercial and Industrial [(a)]	6,683	2,059	4,624	5,580	(17)
Business Metrics					
Weighted average retail customer count (in thousands, metered locations)					
Mass	1,503	1,513	1,499	1,601	(6)
Commercial and Industrial [(a)]	63	63	63	71	(11)
Retail customer count (in thousands, metered locations)					
Mass	1,488	1,513	1,488	1,589	(6)
Commercial and Industrial [(a)]	63	63	63	68	(7)
Cooling Degree Days, or CDDs [(b)]	1,163	149	1,014	971	4%
Heating Degree Days, or HDDs [(b)]	26	25	1	1	

(a) Includes customers of the Texas General Land Office, for whom the Company provides services.

(b) *National Oceanic and Atmospheric Administration-Climate Prediction Center A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period. The CDDs/HDDs amounts are representative of the Coast and North Central Zones within the ERCOT market in which Reliant Energy serves its customer base.*

(c) *For the period May 1, 2009, to June 30, 2009.*

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(In millions except otherwise noted)	Three months ended June 30, 2010	One month ended April 30, 2010	Two months ended June 30, 2010	Two months ended June 30, 2009[(b)]	Change %
Reliant Energy Operating Income:					
Mass revenues	$ 808	$ 190	$ 618	$ 761	(19)%
Commercial and Industrial revenues	502	151	351	437	(20)
Supply management revenues	31	13	18	52	(65)
Total retail operating revenues [(a)]	1,341	354	987	1,250	(21)
Retail cost of sales [(a)]	1,033	280	753	930	(19)
Total retail gross margin	308	74	234	320	(27)
Mark-to-market results on energy supply derivatives	163	39	124	303	(59)
Contract amortization, net	(50)	(20)	(30)	(62)	(52)
Other operating expenses	(113)	(37)	(76)	(90)	(16)
Depreciation and amortization	(29)	(9)	(20)	(43)	(53)
Operating Income	$ 279	$ 47	$ 232	$ 428	(46)%

(a) Amounts exclude unrealized gains/(losses) on energy supply derivatives and contract amortization.

(b) For the period May 1, 2009, to June 30, 2009.

Gross margin excluding April 2010 gross margin of $74 million, Reliant Energy s gross margin decreased by $86 million for May and June. This decrease was primarily due to 22% lower Mass margins driven by price reductions for certain customer classes and lower unit margins on acquisitions, renewals, and conversions from month-to-month to fixed priced contracts. In addition, Mass volumes sold were 8% lower due to fewer customers. Competition, lower unit margins on acquisitions and renewals and supply costs based on forward market prices, could drive lower gross margin in the future.

Operating Income

For the three months ended June 30, 2010 as compared to two months ended June 30, 2009, operating income decreased by $149 million, or $196 million excluding the one month ended April 30, 2010, due to:

Operating Revenues

Total operating revenues increased by $107 million during the three months ended June 30, 2010, as compared to the two months ended June 30, 2009, or decreased by $225 million excluding the one month ended April 30, 2010, due to:

Mass revenues excluding April 2010 revenues of $190 million, Mass revenues decreased by $143 million for May and June. This decrease was primarily due to 12% lower revenue rates driven by Reliant Energy price reductions for certain customer classes and lower revenue pricing on acquisitions, renewals, and conversions from month-to-month to fixed priced contracts consistent with competitive offers. Reliant Energy also experienced 8% lower volumes due to fewer customers driven by 0.6% monthly net attrition between July 2009 and June 2010 from increased competition. Favorable weather in both periods resulted in 11% higher customer usage in 2010 and 9% in 2009 when compared to ten-year normal weather.

Commercial and Industrial revenue excluding April 2010 revenues of $151 million, C&I revenues decreased by $86 million for May and June. This decrease was due to 17% lower volumes primarily driven by fewer customers due to lower renewals and acquisitions and 4% lower revenue rates primarily driven by lower prices on fixed priced renewals due to lower natural gas prices at the time of the renewals.

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Cost of Energy

Cost of energy increased by $247 million for the three months ended June 30, 2010, as compared to the two months ended June 30, 2009, or $8 million excluding the one month ended April 30, 2010, due to:

Supply costs excluding April 2010 supply costs of $187 million, supply costs decreased by $151 million for May and June due to 12% lower volumes in 2010 versus 2009 primarily driven by fewer customers. Supply rates also decreased by 12% due to lower unit prices of purchased power at the time of procurement and favorable impacts of $14 million for out of market supply contracts terminated in the fourth quarter of 2009 in conjunction with the CSRA unwind. The terminated contract value for April 2010 was $7 million.

Transmission and distribution charges excluding April 2010 transmission and distribution charges of $93 million, transmission and distribution charges decreased by $26 million for May and June due to lower volumes transported and sold to customers in 2010 versus 2009. The lower volumes were primarily driven by fewer customers in 2010.

Risk management activities decreased $114 million as $75 million of gains were recorded for the three months ended June 30, 2010 compared to $189 million of gains recorded in the same period in 2009. The $75 million of gains in 2010 consisted of unrealized gains of $163 million, offset by $88 million of realized losses on settled transactions, compared to $303 million of unrealized gains offset by $114 million of realized losses on settled transactions in the same period in 2009. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

Other Operating Expenses

Other operating expenses increased by $23 million for the three months ended June 30, 2010, as compared to the two months ended June 30, 2009. Excluding April 2010 expense of $37 million, other operating expenses decreased by $14 million primarily due to lower labor and related costs of $8 million, lower advertising and marketing costs of $5 million, and lower gross receipts taxes of $3 million, offset by other cost increases of $2 million.

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Year to date Results
Selected Income Statement Data

(In millions except otherwise noted)	**Six months ended June 30, 2010**
Operating Revenues	
Mass revenues	$ 1,521
Commercial and Industrial revenues	991
Supply management revenues	74
Contract amortization	(128)
Total operating revenues	2,458
Operating Costs and Expenses	
Cost of energy (including risk management activities)	2,091
Other operating expenses	216
Depreciation and amortization	59
Operating Income	$ 92
Electricity sales volume GWh	
Mass	10,546
Commercial and Industrial [(a)]	12,892
Business Metrics	
Weighted average retail customers count (in thousands, metered locations)	
Mass	1,512
Commercial and Industrial [(a)]	64
Retail customers count (in thousands, metered locations)	
Mass	1,488
Commercial and Industrial [(a)]	63
Cooling Degree Days, or CDDs [(b)]	1,180
Heating Degree Days, or HDDs [(b)]	1,268

(a) Includes customers of the Texas General Land Office, for whom the Company provides services.

(b) National Oceanic and Atmospheric Administration-Climate Prediction Center A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each

region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period. The CDDs/HDDs amounts are representative of the Coast and North Central Zones within the ERCOT market in which Reliant Energy serves its customer base.

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(In millions)	Six months ended June 30, 2010
Reliant Energy Operating Income:	
Mass revenues	$ 1,521
Commercial and industrial revenues	991
Supply management revenues	74
Total retail operating revenues [a]	2,586
Retail cost of sales [a]	1,985
Total retail gross margin	601
Mark-to-market results on energy supply derivatives	(125)
Contract amortization, net	(109)
Other operating expenses	(216)
Depreciation and amortization	(59)
Operating Income	$ 92

(a) Amounts exclude unrealized gains/(losses) on energy supply derivatives and contract amortization.

Gross margin Reliant Energy s gross margin totaled $601 million for the six months ended June 30, 2010. Higher Mass volumes were driven by favorable weather partially offset a reduction in volumes due to fewer customers driven by 0.4% monthly net attrition between January 2010 and June 2010. In addition, Mass unit margins decreased during the period due to lower margins on acquisitions and renewals driven by competition. A continuation of these factors could drive lower gross margin in the future.

Operating Income

Operating income for the six months ended June 30, 2010, was $92 million, which consisted of the following:

Operating Revenues

Total operating revenues for the six months ended June 30, 2010, were $2.6 billion and consisted of the following:

Mass revenues totaled $1.5 billion for the period from retail electric sales to approximately 1.5 million end use customers in the Texas market. Favorable weather, when compared to ten-year normal weather, resulted in 11% higher usage per customer. However, customer counts declined by 2% during the period. The average Mass revenue rate declined during the period due to lower revenue pricing on acquisitions, renewals and conversions from month-to-month to fixed price contracts consistent with competitive offers.

Commercial and Industrial revenue totaled $991 million for the period on volume sales of approximately 12,892 GWh. Variable rate contracts tied to the market price of natural gas accounted for approximately 45% of the contracted volumes as of June 30, 2010.

Cost of Energy

Cost of energy for the six months ended June 30, 2010, was $2.1 billion and consisted of the following:

Supply costs and financial costs of energy totaled $1.4 billion for the period. Energy is procured for fixed price term contracts at the time the sales contracts are executed. For month-to-month customers, the power is purchased at current market prices. Favorable weather caused an increase in purchased supply volumes during the period. The supply costs were favorably impacted by $48 million of out-of-market supply contracts terminated in the fourth quarter of 2009 in conjunction with the CSRA unwind.

Transmission and distribution charges totaled $634 million for the period for the cost to transport power from the generation sources to the end use customers.

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Risk management activities decreased $437 million as losses of $248 million were reported for the six months ended June 30, 2010 compared to $189 million of gains during the same period in 2009. The $248 million of losses in 2010 consisted of $125 million of mark-to-market losses and $123 million of realized losses on settled transactions, compared to $303 million of mark-to-market gains offset by $114 million of realized losses on settled transactions in the same period in 2009. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

Other Operating Expenses

Other operating expenses for the six months ended June 30, 2010, were $216 million, or 9% of Reliant Energy s total operating revenues. Other operating expenses consisted of the following:

Selling, general and administrative expenses totaled $100 million for the period. Total direct costs were $86 million, which primarily consisted of the costs of labor and external costs associated with advertising and other marketing activities, as well as human resources, community activities, legal, procurement, regulatory, accounting, internal audit, and management, as well as facilities leases and other office expenses. Indirect costs related to corporate allocations were $14 million.

Operations and maintenance expenses totaled $61 million for the six months ended June 30, 2010. These expenses primarily consisted of the labor and external costs associated with customer activities, including the call center, billing, remittance processing, and credit and collections, as well as the information technology costs associated with those activities.

Gross receipts tax totaled $33 million for the period or 1.3% of Mass and C&I revenues.

Bad debt expense totaled $22 million for the period or 0.9% of Mass and C&I revenues. During the period, Reliant Energy experienced improved customer payment behavior.

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Results of Operations for Wholesale Power Generation Regions

The following is a detailed discussion of the results of operations of NRG s major wholesale power generation business segments.

Texas Region

For a discussion of the business profile of the Company s Texas operations, see pages 97-101 of NRG Energy, Inc. s 2009 Annual Report on Form 10-K.

Selected Income Statement Data

	Three months ended June 30,			Six months ended June 30,		
(In millions except otherwise noted)	**2010**	**2009**	**Change %**	**2010**	**2009**	**Change %**
Operating Revenues						
Energy revenue	$ 664	$ 600	11%	$ 1,292	$ 1,194	8%
Capacity revenue	5	47	(89)	12	94	(87)
Risk management activities	(3)	(54)	94	209	209	
Contract amortization	2	17	(88)	4	32	(88)
Other revenues	24	9	167	45	15	200
Total operating revenues	692	619	12	1,562	1,544	1
Operating Costs and Expenses						
Cost of energy (including risk management activities)	260	236	10	480	474	1
Other operating expenses	168	154	9	350	322	9
Depreciation and amortization	124	117	6	241	234	3
Operating Income	$ 140	$ 112	25	$ 491	$ 514	(4)
MWh sold (in thousands)	11,963	12,333	(3)	22,842	22,506	1
MWh generated (in thousands)	11,444	11,919	(4)	21,870	21,992	(1)
Business Metrics						
Average on-peak market power prices ($/MWh)	39.30	38.55	2	40.58	35.57	14
Cooling Degree Days, or CDDs [(a)]	1,004	982	2	1,026	1,108	(7)
CDD s 30 year average	854	854		948	948	
Heating Degree Days, or HDDs [(a)]	79	100	(21)%	1,464	1,003	46%
HDD s 30 year average	83	83		1,205	1,205	

(a) *National Oceanic and Atmospheric Administration-Climate Prediction Center A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean* *temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.*

Quarterly Results

Operating Income

Operating income increased by $28 million for the three months ended June 30, 2010, compared to the same period in 2009, primarily due to an increase in net risk management activities of $55 million and an increase of $22 million driven by higher energy revenues and offset by an increase in the cost of energy of $26 million driven by increased coal costs.

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Operating Revenues

Total operating revenues increased by $73 million during the three months ended June 30, 2010, compared to the same period in 2009, due to:

Risk management activities decreased $51 million as losses of $3 million were reported for the three months ended June 30, 2010, compared to losses of $54 million in the same period in 2009. The $3 million of losses in 2010 included $73 million of unrealized mark-to-market losses and $70 million in settled gains, or financial income, compared to $159 million in unrealized derivative losses and $105 million of settled financial gains in the same period in 2009. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

Energy revenues increased $64 million due to:

- *Energy prices* increased by $66 million for the three months ended June 30, 2010 compared to the same period 2009. The average realized energy price increased by 11%, driven by a 14% increase in merchant prices and a 3% increase in contract prices.

- *Generation* decreased by 2% resulting in a $13 million decrease in sales volume. This decrease was driven by a 1% decrease in coal plant generation due to increased planned maintenance hours in 2010, an 18% decrease in nuclear plant generation due to a planned maintenance outage on Unit 2, and a 6% decrease in gas plant generation. These decreases were offset by an increase in owned and leased wind farm generation, as Langford began commercial operations in December 2009.

- *Margin on MWh sold from market purchases* increased by $12 million for the three months ended June 30, 2010.

Capacity revenue decreased by $42 million due to a lower proportion of baseload contracts which contain a capacity component.

Contract amortization revenue decreased by $15 million due to the reduced volume of contracted energy in 2010 as compared to 2009.

Other revenue increased by $15 million primarily due to higher ancillary services revenue of $17 million offset by a decrease of $2 million in physical sales of natural gas and coal.

Cost of Energy

Cost of energy increased by $24 million during the three months ended June 30, 2010, compared to the same period in 2009, due to:

Coal costs increased by $23 million due to higher cost of transportation.

Ancillary services costs increased by $6 million due to an increase in purchased ancillary services costs incurred to meet obligations.

These increases were offset by:

Natural gas costs decreased by $2 million due to a 6% decrease in gas-fired generation offset by a 26% increase in average natural gas prices.

Purchased energy decreased $2 million due to lower cost of purchases per MWh to meet obligations when baseload plants are unavailable, including a decrease of $8 million from ERCOT congestion and out-of-merit purchases offset by bilateral and toll energy purchases of $6 million.

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Fuel risk management activities increased $4 million as gains of $15 million were recorded for the three months ending June 30, 2010, compared to gains of $11 million during the same period in 2009. The gains of $15 million in 2010 included $16 million of unrealized mark-to-market gains offset by $1 million of losses on settled transactions, compared to $15 million of unrealized mark-to-market gains offset by $4 million in losses on settled transactions, or financial cost of energy, in the same period in 2009. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

Other Operating Expenses

Other operating expenses increased by $14 million during the three months ended June 30, 2010, compared to the same period in 2009, driven by increases in operations and maintenance expense of $11 million due to baseload outages, general and administrative expense of $2 million, and development costs of $1 million.

Year to date results

Operating Income

Operating income decreased by $23 million for the six months ended June 30, 2010, compared to the same period in 2009, primarily due to an increase in the cost of energy of $98 million driven by higher fuel and purchased energy costs and higher operations and maintenance costs of $26 million due to baseload outages, offset by an increase in net risk management activities of $92 million.

Operating Revenues

Total operating revenues increased by $18 million during the six months ended June 30, 2010, compared to the same period in 2009, due to:

Energy revenues increased $98 million due to:

- *Energy prices* increased by $56 million for the six months ended June 30, 2010 compared to the same period 2009. The average realized energy price increased by 5%, driven by a 1% increase in merchant prices and a 3% increase in contract prices.

- *Generation* increased by 3% resulting in a $31 million increase in sales volume. This increase was driven by a 17% increase in gas plant generation and an increase in owned and leased wind farm generation, offset by a 13% decrease in nuclear plant generation due to planned and maintenance outages. Wind farm generation increased due to Langford, which began commercial operations in December 2009.

- *Margin on MWh sold from market purchases* increased by $10 million for the period.

Capacity revenue decreased by $82 million due to a lower proportion of baseload contracts which contain a capacity component.

Contract amortization revenue decreased by $28 million due to the reduced volume of contracted energy in 2010 as compared to 2009.

Other revenue increased by $30 million due to higher ancillary services revenue of $33 million, higher maintenance services revenue of $3 million, and an increase of $2 million in physical sales of natural gas and coal. This increase was offset by $8 million lower emissions credit revenue.

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Cost of Energy

Cost of energy increased by $6 million during the six months ended June 30, 2010, compared to the same period in 2009, due to:

Coal costs increased by $40 million due to higher cost of transportation for WA Parish of $30 million, higher Limestone coal and lignite costs of $12 million, and increased lignite royalty and other costs of $3 million. These increases were offset by reduced generation of $9 million.

Natural gas costs increased by $22 million due to a 17% increase in gas-fired generation and a 23% increase in average natural gas prices.

Ancillary services costs increased by $18 million due to an increase in purchased ancillary services costs incurred to meet obligations.

Purchased energy increased $14 million due to $15 million higher volume and cost of purchases per MWh to meet obligations when baseload plants are unavailable, including a decrease of $9 million from ERCOT congestion and out-of-merit purchases offset by bilateral and toll energy purchases of $8 million.

Emissions amortization amortization of emissions credits increased $6 million due to the increased number of SO_2 credits required by federal rules.

ERCOT nodal fees increased $4 million due to an increase in the per MWh nodal fee by ERCOT.

These increases were offset by:

Fuel risk management activities decreased $92 million due to gains of $38 million recorded for the six months ended June 30, 2010, compared to losses of $54 million during the same period in 2009. The $38 million of gains in 2010 consisted of $40 million of mark-to-market gains offset by $2 million of losses on settled transactions, compared to $41 million of unrealized mark-to-market losses and $13 million in losses on settled transactions in the same period in 2009. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

Other Operating Expenses

Other operating expenses increased by $28 million during the six months ended June 30, 2010, compared to the same period in 2009, driven by increased operations and maintenance expense of $26 million due to baseload outages, and general and administrative expense of $2 million.

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Northeast Region

For a discussion of the business profile of the Northeast region, see pages 101-105 of NRG Energy, Inc. s 2009 Annual Report on Form 10-K.

Selected Income Statement Data

	Three months ended June 30,			Six months ended June 30,		
(In millions except otherwise noted)	**2010**	**2009**	**Change %**	**2010**	**2009**	**Change %**
Operating Revenues						
Energy revenue	$ 115	$ 79	46%	$ 236	$ 260	(9)%
Capacity revenue	100	100		204	196	4
Risk management activities	(15)	51	(129)	32	233	(86)
Other revenues	5	7	(29)	12	12	
Total operating revenues	205	237	(14)	484	701	(31)
Operating Costs and Expenses						
Cost of energy (including risk management activities)	89	58	53	176	175	1
Other operating expenses	73	94	(22)	169	188	(10)
Depreciation and amortization	31	30	3	63	59	7
Operating Income/(Loss)	$ 12	$ 55	(78)	$ 76	$ 279	(73)
MWh sold (in thousands)	1,688	1,634	3	4,077	4,272	(5)
MWh generated (in thousands)	1,688	1,634	3	4,077	4,272	(5)
Business Metrics						
Average on-peak market power prices ($/MWh) [(a)]	54.05	39.68	36	53.46	48.99	9
Cooling Degree Days, or CDDs[(b)]	215	77	179	215	77	179
CDD s 30 year average	105	105		105	105	
Heating Degree Days, or HDDs[(b)]	594	789	(25)%	3,447	3,997	(14)%
HDD s 30 year average	841	841		3,935	3,935	

(a) MWh sold are shown net of MWh purchased to satisfy certain load contracts in the region.

(b) National Oceanic and Atmospheric Administration-Climate Prediction Center A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each

region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

Quarterly Results

Operating Income

Operating income decreased by $43 million for the three months ended June 30, 2010, compared to the same period in 2009 due primarily to a decrease in net risk management activities of $72 million offset by a decrease in other operating expenses of $21 million. Generation activities were relatively flat as increases in energy revenues were mostly offset by increases in cost of energy.

Operating Revenues

Operating revenues decreased by $32 million for the three months ended June 30, 2010, compared to the same period in 2009, due to:

Risk management activities decreased $66 million as losses of $15 million were recorded for the three months ending June 30, 2010, compared to gains of $51 million during the same period in 2009. The $15 million loss in 2010 included $59 million of unrealized mark-to-market losses and $44 million in gains on settled transactions, or financial income, compared to $45 million in unrealized mark-to-market losses and $96 million in financial gains during the same period in 2009. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

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These decreases were offset by:

Energy revenues increased by $36 million due to:

- o *Energy prices* increased by $32 million reflecting an average 50% increase in merchant energy prices.
- o *Generation* increased by $4 million due to a 3% increase in generation in 2010 compared to 2009, which is comprised of a 20% increase in oil and gas generation and a 1% decrease in coal generation. The increase in oil and gas generation is attributable to higher reliability run hours at the Connecticut plants.
- o *Margin on MWh sold from market purchases* decreased by $8 million due to the expiration of load contracts.
- o *Contract revenues* increased by $8 million due to revenues from new load-serving contracts which commenced June 1, 2010.

Capacity revenues remained flat, however reflected higher capacity prices in New York City, offset by a decrease in capacity revenues in New England due to the expiration of the RMR contracts for Montville, Middletown and Norwalk on May 31, 2010.

Cost of Energy

Cost of energy increased by $31 million for the three months ended June 30, 2010, compared to the same period in 2009, due to:

Natural gas and oil costs increased by $13 million, or 47%, due to 37% higher average prices and 20% higher generation.

Coal costs increased by $4 million, or 11%, due to 52% higher average prices offset by a 1% decrease in coal generation as discussed in energy revenues above.

Fuel risk management activities increased $6 million as gains of $4 million were recorded for the three months ending June 30, 2010, related primarily to mark-to-market gains as compared to gains of $10 million in 2009, consisting of $11 million in mark-to-market gains and $1 million in losses on settled transactions, or financial cost of energy. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

Purchased energy increased by $8 million due to costs to supply new load contracts which commenced June 1, 2010.

Other Operating Expenses

Other operating expenses decreased by $21 million for the three months ended June 30, 2010, compared to the same period in 2009, due to:

Property tax expense decreased by $12 million due to increased credits related to the New York Empire Zone program for 2010 and by a $6 million charge in June 2009 to reflect changes in Empire Zone regulations that eliminated the Oswego plant s ability to continue participation in the Empire Zone program.

General & administrative expense decreased $4 million due primarily to a reduction in corporate allocations.

Operations and maintenance expense decreased $4 million due primarily to lower spending at the Arthur Kill plant, which completed a major outage project in the second quarter of 2009.

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Year-to-Date Results

Operating Income

Operating income decreased by $203 million for the six months ended June 30, 2010, compared to the same period in 2009 due primarily to the impact of net risk management activities, which decreased by $201 million. In addition, there were decreases in energy revenues of $24 million that were offset by an increase in capacity revenues of $8 million and a decrease in other operating expenses of $19 million.

Operating Revenues

Operating revenues decreased by $217 million for the six months ended June 30, 2010, compared to the same period in 2009, due to:

Energy revenues decreased by $24 million due to:

- *Energy prices* decreased by $7 million reflecting an average 4% decline in merchant energy prices.

- *Generation* decreased by $13 million due to a 5% decrease in generation in 2010 compared to 2009, driven by a 2% decrease in coal generation and a 19% decrease in oil and gas generation. The decrease in oil and gas generation is attributable to a combination of planned and forced outages as well as reserve shutdowns primarily at Arthur Kill, Middletown and Oswego in the first quarter 2010, offset in part by higher reliability run hours at the Connecticut plants.

- *Margin on MWh sold from market purchases* decreased by $12 million due to the expiration of a load contract in May 2009.

- *Contract revenues* increased by $8 million due to revenues from new load-serving contracts which commenced June 1, 2010.

Risk management activities decreased $201 million as gains of $32 million were recorded for the six months ending June 30, 2010, compared to gains of $233 million during the same period in 2009. The $32 million gain in 2010 included $45 million of unrealized mark-to-market losses and $77 million in gains on settled transactions, or financial income, compared to $77 million in unrealized mark-to-market gains and $156 million in financial income during the same period in 2009. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

This increase was offset by:

Capacity revenues increased by $8 million due to:

- *NYISO* capacity revenues increased by $15 million due to higher capacity prices in New York City driven in part by the retirement of the Poletti facility in January 2010.

- *PJM* capacity revenues increased by $6 million due to higher capacity prices.

- *NEPOOL* capacity revenues decreased by $13 million due to the expiration of the RMR contracts for Montville, Middletown and Norwalk on May 31, 2010. These plants now operate as fully merchant facilities.

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Cost of Energy

Cost of energy increased by $1 million for the six months ended June 30, 2010, compared to the same period in 2009, due to:

Purchased energy increased by $8 million due to costs to supply new load contracts, which commenced June 1, 2010.

Fuel risk management activities remained flat as gains of $15 million were recorded for the six months ending June 30, 2010, related to mark-to-market gains, as compared to gains of $15 million in 2009, consisting of $20 million in mark-to-market gains and $5 million in losses on settled transactions, or financial cost of energy. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

These increases were offset by:

Natural gas and oil costs decreased by $5 million, or 7%, due to 19% lower generation offset by 17% higher average prices.

Other Operating Expenses

Other operating expenses decreased by $19 million for the six months ended June 30, 2010, compared to the same period in 2009, due to:

Property taxes decreased by $11 million due to increased credits related to the New York Empire Zone program for 2010 and by a $6 million charge in June 2009 to reflect changes in Empire Zone regulations that eliminated the Oswego plant s ability to continue participation in the Empire Zone program.

ARO accretion expense decreased $4 million due to a change in estimate for an ARO liability at the Huntley and Dunkirk plants.

General and administrative expense decreased $10 million due primarily to a reduction in corporate allocations.

These decreases were offset by:

Operations and maintenance expense increased $6 million due primarily to $12 million in charges relating to the write-off of previously capitalized costs on the Indian River Unit 3 back end controls project together with associated cancellation penalties and write-offs for other asset retirements of $8 million. In addition, 2009 includes credits of $4 million booked to reflect resolution of certain station service liabilities. These increases were offset by decreases in normal and major maintenance of $17 million mainly due to lower spending at the Indian River and Arthur Kill plants, which completed a major outage project in the second quarter of 2009.

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South Central Region

For a discussion of the business profile of the South Central region, see pages 106-109 of NRG Energy, Inc. s 2009 Annual Report on Form 10-K.

Selected Income Statement Data

(In millions except otherwise noted)	Three months ended June 30, 2010	2009	Change%	Six months ended June 30, 2010	2009	Change%
Operating Revenues						
Energy revenue	$ 96	$ 81	19%	$ 202	$ 177	14%
Capacity revenue	58	65	(11)	115	133	(14)
Risk management activities	(7)	(12)	42	(32)	(19)	(68)
Contract amortization	5	5		10	11	(9)
Other revenues					(1)	100
Total operating revenues	152	139	9	295	301	(2)
Operating Costs and Expenses						
Cost of energy (including risk management activities)	80	92	(13)	177	202	(12)
Other operating expenses	41	27	52	63	49	29
Depreciation and amortization	16	17	(6)	32	34	(6)
Operating Income	$ 15	$ 3	400	$ 23	$ 16	44
MWh sold (in thousands)	3,221	2,792	15	6,399	5,961	7
MWh generated (in thousands)	2,366	2,386	(1)	5,008	5,093	(2)
Business Metrics						
Average on-peak market power prices ($/MWh)	38.96	32.21	21	41.13	34.75	18
Cooling Degree Days, or CDDs[(a)]	689	582	18	689	588	17
CDD s 30 year average	458	458		489	489	
Heating Degree Days, or HDDs[(a)]	182	289	(37)%	2,423	2,094	16%
HDD s 30 year average	299	299		2,194	2,194	

(a) *National Oceanic and Atmospheric Administration-Climate Prediction Center A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The*

CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

Quarterly Results

Operating income increased by $12 million for the three months ended June 30, 2010, due to the favorable impact of $22 million in net risk management activities offset by $14 million of higher operating expenses.

Operating Revenues

Operating revenues increased by $13 million for the three months ended June 30, 2010, compared to the same period in 2009, due to:

Energy revenues increased by $15 million due to a $19 million rise in contract revenue offset by a decline of $4 million in merchant energy revenues. Total megawatt hours sold to the region s contract customers increased 13% reflecting the impact of a new contract with a regional municipality and higher sales to cooperative customers. The new contract added an additional $12 million and a fuel pass-through to the cooperative customers increased $6 million. The average realized price on contract energy sales was $27.77 per MWh in 2010 compared to $22.98 per MWh in 2009. Megawatt hours sold to the merchant market increased by 26% but lower realized merchant prices resulted in a drop of $4 million.

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Risk management activities increased $5 million as losses of $7 million were recorded for the three months ended June 30, 2010 compared to losses of $12 million during the same period in 2009. The $7 million loss in 2010 included $1 million in unrealized gains and $8 million in realized losses compared to $10 million in unrealized losses and $2 million in realized losses for the same period in 2009. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

Capacity revenues capacity revenue decreased by $7 million due to an $8 million decrease resulting from the expiration of a capacity agreement offset by higher capacity revenue associated with the region s contract customers.

Cost of Energy

Cost of energy decreased by $12 million for the three months ended June 30, 2010, compared to the same period in 2009, due to:

Fuel risk management activities decreased $17 million as gains of $9 million were recorded for the three months ended June 30, 2010, related to mark-to-market gains, as compared to a loss of $8 million recorded in 2009, consisting of $5 million in unrealized losses and $3 million in realized losses. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

This decrease was offset by:

Purchased energy Total purchased power increased by $5 million as increased load requirements were met with market purchases.

Other Operating Expenses

Other operating expense increased by $14 million for the three months ended June 30, 2010, compared to the same period in 2009. The scope of work and duration of the 2010 outage at the region s coal facility was greater than the outage work performed in 2009. Outage work is performed in accordance with the region s long-term maintenance plan.

Year-to-Date Results

Operating income increased by $7 million for the six months ended June 30, 2010, due to the favorable impact of $22 million in net risk management activities offset by $14 million of higher operating expenses.

Operating Revenues

Operating revenues decreased by $6 million for the six months ended June 30, 2010 compared to the same period in 2009 due to:

Energy revenues increased by $25 million due to a $31 million increase in contract revenue offset by a $6 million decrease in merchant energy revenues. The increase is attributable to the region s cooperative customers from fuel cost pass-through which contributed $12 million and increased volume $6 million. The new contract with a regional municipality added an additional $12 million. Merchant megawatt hour sales fell by 5% and average realized prices were down by $1.75 MWh.

Capacity revenues decreased by $18 million due to the expiration of a capacity agreement with a regional utility.

Risk management activities decreased by $13 million as losses of $32 million were recorded for the six months ended June 30, 2010 compared to losses of $19 million recognized during the same period in 2009. The $32 million loss in 2010 included $12 million in unrealized losses and $20 million of realized losses, compared to $30 million in unrealized losses offset by $11 million in realized gains for the same period in 2009. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

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Cost of Energy

Cost of energy decreased by $25 million for the six months ended June 30, 2010, compared to the same period in 2009, due to:

Fuel risk management activities decreased $35 million as gains of $19 million were recorded for the six months ended June 30, 2010, compared to losses of $16 million during the same period in 2009. The $19 million of gains in 2010 included $20 million of unrealized gains offset by $1 million of realized losses, compared to $10 million in unrealized losses and $6 million in realized losses for the same period in 2009. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

Coal costs dropped by $4 million due to a 1% reduction in coal generation.

These decreases were offset by:

Purchased energy increased by $11 million as increased load requirements were met with market purchases.

Other Operating Expenses

Other operating expense increased by $14 million for the six months ended June 30, 2010, compared to the same period in 2009. The scope of work and duration of the 2010 outage at the region s coal facility was greater than the outage work performed in 2009. Outage work is performed in accordance with the region s long-term maintenance plan.

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West Region

For a discussion of the business profile of the West region, see pages 110-112 of NRG Energy, Inc. s 2009 Annual Report on Form 10-K.

Selected Income Statement Data

(In millions except otherwise noted)	Three months ended June 30, 2010	2009	Change%	Six months ended June 30, 2010	2009	Change%
Operating Revenues						
Energy revenue	$ 2	$ 5	(60)%	$ 10	$ 7	43%
Capacity revenue	27	31	(13)	53	60	(12)
Risk management activities	3	6	(50)	4	3	33
Total operating revenues	32	42	(24)	67	70	(4)
Operating Costs and Expenses						
Cost of energy (including risk management activities)	1	3	(67)	6	7	(14)
Other operating expenses	20	21	(5)	41	46	(11)
Depreciation and amortization	3	2	50	6	4	50
Operating Income	$ 8	$ 16	(50)	$ 14	$ 13	8
MWh sold (in thousands)	28	62	(55)	97	76	28
MWh generated (in thousands)	28	62	(55)	97	76	28
Business Metrics						
Average on-peak market power prices ($/MWh)	35.40	33.14	7	41.64	36.80	13
Cooling Degree Days, or CDDs[(a)]	75	144	(48)	75	144	(48)
CDD s 30 year average	150	150		157	157	
Heating Degree Days, or HDDs[(a)]	674	470	43%	2,004	1,880	7%
HDD s 30 year average	556	556		1,975	1,975	

(a) National Oceanic and Atmospheric Administration-Climate Prediction Center A CDD represents the number of degrees that the mean temperature for a particular day is above 65 degrees Fahrenheit in each region. An HDD represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit in each region. The

CDDs/HDDs for a period of time are calculated by adding the CDDs/HDDs for each day during the period.

Quarterly Results

Operating Income

Operating income decreased by $8 million for the three months ended June 30, 2010, compared to the same period in 2009.

Operating Revenues

Operating revenues decreased by $10 million for the three months ended June 30, 2010, compared to the same period in 2009, due to:

Energy revenues decreased by $3 million primarily due to a 55% decrease in generation and an 11% decline in merchant energy prices in 2010 compared to 2009. This increase includes $2 million in energy revenue related to Blythe Solar, which began commercial operation in December 2009.

Capacity revenues decreased by $4 million due to a reduction in resource adequacy and call option contract sales at El Segundo in 2010 compared to 2009.

Risk management activities decreased $3 million as gains of $3 million were recorded for the three months ended June 30, 2010, compared to gains of $6 million during the same period in 2009. The $3 million of gains in 2010 included $2 million of unrealized mark-to-market gains and $1 million in gains on settled transactions, or financial income, compared to $7 million in unrealized mark-to-market gains and $1 million in financial losses during the same period in 2009. Please refer to the Consolidated Results of Operations to this Form 10-Q for a more complete description of movements in risk management activities.

Cost of Energy

Cost of energy decreased by $2 million for the three months ended June 30, 2010, compared to the same period in 2009, due to a 77% decrease in natural gas consumption due to lower generation. This decrease was partially offset by a 44% increase in average natural gas prices per MMBtu.

Year-to-Date Results

Operating income increased by $1 million for the six months ended June 30, 2010, compared to the same period in 2009.

Operating Revenues

Operating revenues decreased by $3 million for the six months ended June 30, 2010, compared to the same period in 2009, due to:

Capacity revenues decreased by $7 million primarily due to reduced resource adequacy and call option contract sales at El Segundo in 2010 compared to 2009.

Energy revenues increased by $3 million primarily due to incremental revenue from the commencement of operations at Blythe Solar. The region experienced a 28% increase in generation and a 3% increase in merchant energy prices in 2010 compared to 2009.

Cost of Energy and Other Operating Expenses

Cost of energy and other operating expenses decreased by $6 million for the six months ended June 30, 2010, compared to the same period in 2009, due to:

Cost of energy decreased by $1 million due to $3 million of expense in 2009 resulting from a write-down to market of fuel oil inventory no longer used in the production of energy. This decrease was offset by a $2 million increase in natural gas expense due to a 47% increase in average natural gas prices per MMBtu and a 12% decrease in natural gas consumption.

Other operating expenses decreased by $5 million due to lower major maintenance expense associated with a major overhaul at El Segundo in 2009.

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Liquidity and Capital Resources

Liquidity Position

As of June 30, 2010, and December 31, 2009, NRG s liquidity, excluding collateral received, was approximately $3.5 billion and $3.8 billion, respectively, comprised of the following:

(In millions)	June 30, 2010	December 31, 2009
Cash and cash equivalents	$2,168	$ 2,304
Funds deposited by counterparties	310	177
Restricted cash	13	2
Total cash	2,491	2,483
Funded Letter of Credit Facility availability	480	583
Revolving Credit Facility availability	839	905
Total liquidity	3,810	3,971
Less: Funds deposited as collateral by hedge counterparties	(310)	(177)
Total liquidity, excluding collateral received	$3,500	$ 3,794

For the six months ended June 30, 2010, total liquidity, excluding collateral received, decreased by $294 million due to lower cash and cash equivalent balances of $136 million, decreased availability of the Funded Letter of Credit Facility of $103 million, and decreased availability of $66 million in the Revolving Credit Facility. The Revolving Credit Facility availability decrease was due to a decrease in capacity of $125 million as a result of the refinancing of the Senior Credit Facility, offset by an increase of $59 million due to the cancellation in February 2010 of the letter of credit issued in support of the Dunkirk bonds, as described below and further in Note 8, *Long-Term Debt*. Changes in cash and cash equivalent balances are further discussed below under the heading *Cash Flow Discussion*. Cash and cash equivalents and funds deposited by counterparties at June 30, 2010, were predominantly held in money market funds invested in treasury securities, treasury repurchase agreements or government agency debt.

The line item Funds deposited by counterparties represents the amounts that are held by NRG as a result of collateral posting obligations from the Company s counterparties due to positions in the Company s hedging program. These amounts are segregated into separate accounts that are not contractually restricted but, based on the Company s intention, are not available for the payment of NRG s general corporate obligations. Depending on market fluctuation and the settlement of the underlying contracts, the Company will refund this collateral to the counterparties pursuant to the terms and conditions of the underlying trades. Since collateral requirements fluctuate daily and the Company cannot predict if any collateral will be held for more than twelve months, the funds deposited by counterparties are classified as a current asset on the Company s balance sheet, with an offsetting liability for this cash collateral received within current liabilities.

Management believes that the Company s liquidity position and cash flows from operations will be adequate to finance operating and maintenance capital expenditures and other liquidity commitments. Management continues to regularly monitor the Company s ability to finance the needs of its operating, financing and investing activity in a manner consistent with its intention to maintain a net debt to capital ratio in the range of 45-60%.

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SOURCES OF FUNDS

The principal sources of liquidity for NRG s future operating and capital expenditures are expected to be derived from new and existing financing arrangements, existing cash on hand and cash flows from operations.

Financing Arrangements

Senior Credit Facility

On June 30, 2010, NRG completed an amendment and extension, or the Amendment, of its Senior Credit Facility. NRG s Senior Credit Facility is comprised of the Term Loan Facility, the Funded Letter of Credit Facility and the Revolving Credit Facility. As a result of the Amendment, NRG extended the maturity date for approximately $1.0 billion of the $2.0 billion outstanding Term Loan Facility to August 31, 2015, and the remaining amount is due on the original maturity date of February 1, 2013. In addition, borrowing capacity under the Revolving Credit Facility was reduced from $1.0 billion to $875 million and its maturity was extended to August 31, 2015. Finally, the Synthetic Letter of Credit Facility was converted into a term loan-backed Funded Letter of Credit Facility (on an on-balance sheet basis), with term loans in an amount of $800 million maturing on August 31, 2015, and $500 million maturing on the original maturity date of February 1, 2013. As of June 30, 2010, NRG had issued $820 million of letters of credit under the Funded Letter of Credit Facility, leaving $480 million available for future issuances. Under the Revolving Credit Facility as of June 30, 2010, NRG had issued a letter of credit of $36 million, leaving $839 million available.

TANE Facility

On February 24, 2009, NINA executed an Engineering, Procurement and Construction, or EPC, agreement with TANE, which specifies the terms under which STP Units 3 and 4 will be constructed. Concurrent with the execution of the EPC agreement, NINA and TANE entered into the TANE Facility, wherein TANE has committed up to $500 million to finance purchases of long-lead materials and equipment for the construction of STP Units 3 and 4. The TANE Facility matures on February 24, 2012, subject to two renewal periods, and provides for customary events of default, which include, among others: nonpayment of principal or interest; default under other indebtedness; the rendering of judgments; and certain events of bankruptcy or insolvency. Outstanding borrowings will accrue interest at LIBOR plus 3%, subject to a ratings grid, and are secured by substantially all of the assets of and membership interests in NINA and its subsidiaries. As of June 30, 2010, $3 million has been borrowed under the TANE Facility.

NRG Non-Recourse Project Financings

During the second quarter 2010, three of the Company s subsidiaries completed the following project level financings which are non-recourse to NRG. See Note 8, *Long-Term Debt*, to this Form 10-Q for a more complete description of these project financings.

(in millions)	**As of June 30, 2010**
NRG Solar Blythe LLC, term loan due 2028	$ 30
South Trent Wind LLC, term loan due 2020	$ 79
NRG Energy Center Minneapolis LLC, senior secured notes due 2025	$ 100

GenConn Energy LLC related financings

NRG Connecticut Peaking Development LLC made funding requests under the EBL during the quarter. The EBL is backed by a letter of credit issued by NRG under its Funded Letter of Credit Facility equal to 104% of the amount outstanding. The proceeds of the EBL received through June 30, 2010, were $115 million and the remaining amounts will be drawn as necessary to fund interest on the EBL as the maximum amount permitted to be drawn for project costs for both projects has been met. Of the $115 million, $55 million was drawn to fund Devon project costs and will become due and payable upon COD of the Devon project, which is expected to occur in the third quarter of 2010.

In April 2009, GenConn secured financing for 50% of the Devon and Middletown project construction costs through a seven-year term loan facility, and also entered into a five-year revolving working capital loan and letter of credit facility, which collectively with the term loan is referred to as the GenConn Facility. The aggregate credit amount secured under the GenConn Facility, which is non-recourse to NRG, is $291 million, including $48 million for the revolving facility. In August 2009, GenConn began to draw under the GenConn Facility to cover costs related to the Devon project, and in June 2010 began to draw to cover costs related to the Middletown project. As of June 30, 2010, $109 million had been drawn.

First and Second Lien Structure

NRG has granted first and second liens to certain counterparties on substantially all of the Company s assets. NRG uses the first and second lien structure to reduce the amount of cash collateral and letters of credit that it would otherwise be required to post from time to time to support its obligations under out-of-money hedge agreements for forward sales of power or MWh equivalents. To the extent that the underlying hedge positions for a counterparty are in-the-money to NRG, the counterparty would have no claim under the lien program. The lien program limits the volume that can be hedged, not the value of underlying out-of-money positions. The first lien program does not require NRG to post collateral above any threshold amount of exposure. Within the first and second lien structure, the Company can hedge up to 80% of its baseload capacity and 10% of its non-baseload assets with these counterparties for the first 60 months and then declining thereafter. Net exposure to a counterparty on all trades must be positively correlated to the price of the relevant commodity for the first lien to be available to that counterparty. The first and second lien structure is not subject to unwind or termination upon a ratings downgrade of a counterparty or NRG and has no stated maturity date.

The Company s lien counterparties may have a claim on its assets to the extent market prices exceed the hedged price. As of June 30, 2010, all hedges under the first and second liens were in-the-money on a counterparty aggregate basis.

The following table summarizes the amount of MWs hedged against the Company s baseload assets and as a percentage relative to the Company s baseload capacity under the first and second lien structure as of June 30, 2010:

Equivalent Net Sales Secured by First and Second Lien Structure[(a)]	**2010**	**2011**	**2012**	**2013**
In MW[(b)]	2,793	2,222	1,439	736
As a percentage of total net baseload capacity[(c)]	41%	33%	21%	11%

(a) Equivalent Net Sales include natural gas swaps converted using a weighted average heat rate by region.

(b) 2010 MW value consists of July through December positions only.

(c) Net baseload capacity under

the first and second lien structure represents 80% of the Company s total baseload assets.

USES OF FUNDS

The Company s requirements for liquidity and capital resources, other than for operating its facilities, can generally be categorized by the following: (i) commercial operations activities; (ii) debt service obligations; (iii) capital expenditures including *Repowering*NRG and environmental; and (iv) corporate financial transactions including return of capital to shareholders.

Commercial Operations

NRG s commercial operations activities require a significant amount of liquidity and capital resources. These liquidity requirements are primarily driven by: (i) margin and collateral posted with counterparties; (ii) initial collateral required to establish trading relationships; (iii) timing of disbursements and receipts (i.e., buying fuel before receiving energy revenues); and (iv) initial collateral for large structured transactions. As of June 30, 2010, commercial operations had total cash collateral outstanding of $391 million, and $537 million outstanding in letters of credit to third parties primarily to support its economic hedging activities for both wholesale and retail transactions (includes a $60 million letter of credit relating to deposits at the PUCT that covers outstanding customer deposits and residential advance payments). As of June 30, 2010, total collateral held from counterparties was $310 million and $11 million of letters of credit.

Future liquidity requirements may change based on the Company s hedging activities and structures, fuel purchases, and future market conditions, including forward prices for energy and fuel and market volatility. In addition, liquidity requirements are dependent on NRG s credit ratings and the general perception of its creditworthiness.

Debt Service Obligations

NRG must annually offer a portion of its excess cash flow, as defined in the Senior Credit Facility, to its first lien lenders under the Term Loan Facility. The percentage of excess cash flow offered to these lenders is dependent upon the Company s consolidated leverage ratio, as defined in the Senior Credit Facility, at the end of the preceding year. Of the amount offered, the first lien lenders must accept 50% while the remaining 50% may either be accepted or rejected at the lenders option. In March 2010, NRG made and the lenders accepted a repayment of approximately $229 million for the mandatory annual offer relating to 2009.

Debt Related to Capital Allocation Program

On March 3, 2010, the Company completed the early unwinding of the CSF I Debt by remitting a cash payment to CS of $242 million to settle the outstanding principal and interest, as compared to $249 million that would have been due at maturity in June 2010. The Company has now settled all obligations related to the CSF I and II Debt entered into in 2006, as amended from time to time, as well as the SLA entered into in February 2009.

Acquisitions

During the second quarter 2010, the Company completed the acquisitions of Northwind Phoenix and South Trent, for combined consideration totaling $211 million. See Note 4, *Business Acquisitions and Dispositions*, to this Form 10-Q for a more complete description of these acquisitions.

2010 Capital Allocation Plan

In the second quarter 2010, as part of the Company s 2010 Capital Allocation Plan, the Company repurchased $50 million of its common stock. NRG intends to complete the remainder of its $180 million of share repurchases by the end of 2010, subject to market prices, financial restrictions under the Company s debt facilities and as permitted by securities laws.

Capital Expenditures

The following table summarizes the Company s capital expenditures, including accruals, for the six months ended June 30, 2010, and the estimated capital expenditure and repowering investments forecast for the remainder of 2010. As discussed below, the Repowering expenditures include amounts anticipated to be funded from sources other than NRG.

(In millions)	**Maintenance**	**Environmental**	**Repowering**	**Total**
Northeast	$ 5	$ 83	$ 1	$ 89
Texas	41			41
South Central	7			7
West	2		7	9
Reliant Energy	3			3
Nuclear development			279	279
Other	22		5	27
Total for the six months ended June 30, 2010	$ 80	$ 83	$ 292	$455
Estimated capital expenditures for the remainder of 2010	$ 166	$ 111	$ 194	$471

*Repowering*NRG *capital expenditures* *Repowering*NRG project capital expenditures consisted of approximately $279 million related to the development of STP Units 3 and 4 in Texas.

NRG s net expenditures for STP Units 3 and 4 for 2010, funded from operating activities, are anticipated to be approximately $286 million. In addition, NINA anticipates net funding of approximately $170 million of 2010 capital expenditures from sources other than NRG, including draws on the TANE long-lead material facility, Toshiba equity contributions, and TEPCO equity contributions upon NINA s acceptance of a U.S. DOE loan guarantee commitment. NINA is also exploring additional funding alternatives with existing project constituents in the event a U.S. DOE loan guarantee is not received in a timely fashion. In early 2010, NRG announced that if this project did not receive a loan guarantee from the U.S. DOE in a timely fashion, it was the intention of the Company both to reduce substantially its commitment to fund on-going project expenditures as well as to reduce development spending on the project overall while the outcome of the loan guarantee was uncertain. See Note 15, *Commitments and Contingencies*, to this Form 10-Q for further discussion.

Major maintenance and environmental capital expenditures The Company s maintenance capital expenditures were $80 million, of which $41 million was related to the Texas region s assets, including approximately $15 million in nuclear fuel expenditures related to STP Units 1 and 2. The Company s environmental capital expenditures were $83 million, of which $73 million was due to a project to install selective catalytic reduction systems, scrubbers and fabric filters on Indian River Unit 4 with an expected in service date of year end 2011.

Loans to affiliates The equity portion of construction costs for GenConn is funded through the EBLs of NRG Connecticut Peaking and The United Illuminating Company, or United Illuminating. These funds are made available to GenConn through interest bearing promissory notes that convert to equity upon repayment of the EBL loans by NRG Connecticut Peaking and United Illuminating. As of June 30, 2010, there was $116 million outstanding under the loan from NRG Connecticut Peaking.

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures from 2010 through 2014 to meet NRG s environmental commitments will be approximately $0.9 billion. These capital expenditures, in general, are related to installation of particulate, SO_2, NO_x, and mercury controls to comply with federal and state air quality rules and consent orders, as well as installation of Best Technology Available under the Phase II 316(b) Rule. NRG continues to explore cost effective alternatives that can achieve desired results. While this estimate reflects schedules and controls to meet anticipated reduction requirements, the full impact on the scope and timing of environmental retrofits cannot be determined until issuance of final rules by the U.S. EPA.

This estimate reflects the recent announcement to retrofit only Unit 4 at the Indian River Generating Station and shifts in the timing of other projects to reflect anticipated issuance dates for revised regulations.

NRG s current contracts with the Company s rural electrical customers in the South Central region allow for recovery of a portion of the regions capital costs once in operation, along with a capital return incurred by complying with new laws, including interest over the asset life of the required expenditures. The actual recoveries will depend, among other things, on the timing of the completion of the capital project and the remaining duration of the contracts.

Preferred Stock Dividend Payments

For the six months ended June 30, 2010, NRG paid approximately $5 million in dividends to holders of the Company s 3.625% Preferred Stock.

Reliant Energy Customer Deposits

Revisions in the PUCT rules required that NRG keep a segregated account, or that the Company post a fully collateralized letter of credit on or before May 21, 2010, to cover outstanding customer deposits and residential advance payments. The Company filed an amendment to its Retail Electric Provider certificate in the first quarter of 2010, which was approved by the PUCT, and posted a letter of credit to satisfy the rule changes. The amount of deposits subject to segregation as of June 30, 2010, was approximately $54 million.

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Cash Flow Discussion

The following table reflects the changes in cash flows for the comparative years; all cash flow categories include the cash flows from both continuing operations and discontinued operations:

(In millions) Six months ended June 30,	2010	2009	Change
Net cash provided by operating activities	$ 605	$ 722	$(117)
Net cash used by investing activities	(385)	(500)	115
Net cash (used)/provided by financing activities	(347)	565	(912)

Net Cash Provided By Operating Activities

For the six months ended June 30, 2010, net cash provided by operating activities decreased by $117 million compared to the same period in 2009, due to:

Lower cash flows from Wholesale Power Generation The Company s cash flow from operating activities excluding Reliant Energy was lower by $370 million, mainly due to a $381 million decrease in operating income adjusted for non-cash charges, offset by a $6 million increase in net collateral deposits paid and option premiums paid and collected, as well as a $5 million increase in working capital for 2010 as compared to the same period in 2009.

Cash generated by Reliant Energy Reliant Energy contributed approximately $442 million to the Company s consolidated cash flow from operating activities for the first six months of 2010, compared with $189 million for the two months ended June 30, 2009.

Net Cash Used By Investing Activities

For the six months ended June 30, 2010, net cash used by investing activities decreased by $115 million compared to the same period in 2009, due to:

Cash for Acquisitions During 2010, the Company paid $141 million, primarily for the acquisitions of Northwind Phoenix and South Trent. During 2009, the Company paid $345 million for the acquisition of Reliant Energy.

Proceeds from renewable energy grants During 2010, the Company received $102 million of federal cash grants for the Blythe solar and Langford wind facilities.

Capital expenditures and loans to affiliates NRG s capital expenditures decreased by $44 million due to decreased spending on maintenance, *Repowering*NRG, and environmental projects. Loans to affiliates reflects a net increase in cash of $26 million in 2010 as compared to 2009.

Proceeds from sale of assets Net proceeds increased by $24 million in 2010 as compared to 2009 due to the sale of Padoma in January 2010.

Proceeds from sale of equity method investment Proceeds from investing activities decreased in 2010 as compared to 2009 due to the sale of MIBRAG in June 2009 for net proceeds of $284 million.

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Net Cash Used By Financing Activities

For the six months ended June 30, 2010, net cash used by financing activities was $347 million, compared with net cash provided by financing activities of $565 million for the same period in 2009, a net cash decrease of $912 million, due to:

Lower issuance of debt During 2010, the Company issued $130 million under new debt facilities and $14 million under existing debt facilities. The new debt facilities consist of $100 million by NRG Thermal and $30 million by Blythe. During 2009, the Company received $25 million from the initial draw under the Reliant Energy working capital facility, $34 million from the Dunkirk bonds, $70 million in GenConn financings and $688 million in gross proceeds from the 2019 Senior Notes.

Increase in term loan and other facility payments In 2010, the Company paid down $240 million of its Term Loan Facility, including the payment of excess cash flow, as discussed above under *Debt Service Obligations*. In addition, NINA paid $20 million under its revolving credit facility. In 2009, the Company paid down $213 million of its Term Loan Facility.

Repayment of CSF I Debt During 2010, the Company paid $190 million in principal to early settle the CSF I Debt.

Share repurchases During 2010, the Company repurchased $50 million of NRG common stock.

Net receipt from acquired derivatives that include financing elements In 2010, the Company received a net of $27 million for the settlement of gas swaps compared with a payment of $22 million for 2009 for the settlement of gas swaps related to Reliant Energy and Texas Genco.

Increase in deferred financing costs During 2010, deferred financing costs primarily consist of fees paid as a result of the amendment and extension of the Senior Credit Facility. During 2009, the Company paid lower deferred financing costs related to the Reliant Energy CSRA, the 2019 Senior Notes, the Dunkirk bonds and the Reliant Energy working capital facility.

Decrease in preferred stock dividends During 2010, dividend payments on preferred stock decreased by $16 million as compared to the same period in 2009 due to the conversion of the 5.75% Preferred Stock in 2009 and the conversion of the 4% Preferred Stock, which was completed in January 2010.

NOLs, Deferred Tax Assets and Uncertain Tax Position Implications, under ASC-740, Income Taxes, or ASC 740

As of June 30, 2010, the Company had generated total domestic pre-tax book income of $410 million and foreign pre-tax book income of $40 million. The Company has net operating losses for tax return purposes available to offset taxable income in the current period. In addition, NRG has cumulative foreign NOL carryforwards of $240 million, of which $71 million will expire starting in 2011 through 2017 and of which $169 million do not have an expiration date.

In addition to these amounts, the Company has $635 million of tax effected unrecognized tax benefits which relate primarily to net operating losses for tax return purposes but have been classified as capital loss carryforwards for financial statement purposes and for which a full valuation allowance has been established. As a result of the Company s tax position, and based on current forecasts, NRG anticipates income tax payments, primarily due to foreign, state and local jurisdictions, of up to $75 million in 2010.

However, as the position remains uncertain for the $635 million of tax effected unrecognized tax benefits, the Company has recorded a non-current tax liability of $512 million and may accrue the remaining balance as an increase to non-current liabilities until final resolution with the related taxing authority. The $512 million non-current tax liability for unrecognized tax benefits is primarily due to taxable earnings for which there are no NOLs available to offset for financial statement purposes.

The Company is under examination by the Internal Revenue Service for years 2004 through 2006, as well as various state jurisdictions for multiple years.

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New and On-going Company Initiatives, Development Projects and Acquisitions

FOR*NRG Update*

Beginning in January 2009, the Company transitioned to *FOR*NRG 2.0 to target an incremental 100 basis point improvement to the Company s ROIC by 2012. The initial targets for *FOR*NRG 2.0 were based upon improvements in the Company s ROIC as measured by increased cash flow. The economic goals of *FOR*NRG 2.0 will focus on: (i) revenue enhancement; (ii) cost savings; and (iii) asset optimization, including reducing excess working capital and other assets. The *FOR*NRG 2.0 program will measure its progress towards the *FOR*NRG 2.0 goals by using the Company s 2008 financial results as a baseline, while plant performance calculations will be based upon the appropriate historic baselines.

The 2010 *FOR*NRG goal is 65 basis points improvement, which corresponds to approximately $98 million in cash flows. The goal is inclusive of benefits created in 2009 and new project benefits reported in 2010. As of the second quarter 2010, the Company has delivered a 33 basis point improvement in ROIC, which is equivalent to approximately $49 million in cash flows to the *FOR*NRG program. During 2010, the Company expects to progress further toward the program goal of 100 basis point ROIC improvement by 2012.

***Repowering*NRG Update**

NRG has several projects in varying stages of development. The Company s development projects are generally subject to certain conditions, milestones, or other factors that may result in the Company s decision to no longer pursue the development of these projects. Projects that have achieved a significant milestone, financing, or other material developments are more fully described in the Company s 2009 Annual Report on Form 10-K and this Quarterly Report on Form 10-Q.

Air permitting litigation unrelated to the El Segundo project has delayed receipt of certain required permits, including an air permit, which will prevent the El Segundo project from meeting its original completion date of June 2011. However, legislation enacted on January 1, 2010, has allowed the affected air district to issue air permits like El Segundo s. A revised draft air permit was issued in April 2010 by the South Coast Air Quality Management District, or SCAQMD, allowing the project permitting to proceed. On June 30, 2010, the California Energy Commission approved the construction permit, and the Company is now awaiting the issuance of the final air permit by SCAQMD. The Company is working with the power purchaser to consider certain PPA modifications including a revised commercial operations date, currently expected to be the summer of 2013.

On March 9, 2010, NRG was selected by the U.S. DOE to negotiate to receive up to $167 million, including funding from the American Recovery and Reinvestment Act, to build a 60 MW post-combustion carbon capture demonstration unit at NRG s WA Parish plant southwest of Houston with use of the captured carbon in enhanced oil recovery in adjacent oil fields. The proposed project was submitted under the Clean Coal Power Initiative Program, or CCPI, a cost-shared collaboration between the federal government and private industry to demonstrate carbon capture and storage technologies in existing coal-based, power generation. On May 7, 2010, the Company executed a cooperative agreement with the U.S. DOE which defines the basis for cost sharing in the development and initial operations of the facility. The project currently is in the design engineering phase. Construction would begin in late 2012 with commercial operations anticipated in the fourth quarter 2014.

The following is a summary of the 2010 repowering projects that are currently under construction. In addition, NRG continues to participate in active bids in response to requests for proposals in markets in which it operates.

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Plants under Construction

GenConn Energy LLC GenConn Energy, a 50/50 joint venture of NRG and The United Illuminating Company, or United Illuminating, formed to construct, own and operate peaking generation facilities in Connecticut, is in the construction phase of two, 200 MW peaking facilities at NRG s Devon and Middletown sites. Each of these facilities is being constructed pursuant to 30-year contracts for differences with The Connecticut Light & Power Company. Three of the four units at the GenConn Devon facility were released to the ISO-NE during June 2010 and the last unit was released to ISO-NE in mid July 2010. The Middletown project, which is fully permitted, is in the early stages of construction, with a target commercial operation date of June 1, 2011.

GenConn was directed by the Connecticut Department of Public Utility Control to bid the full capacity of the GenConn Devon facility into the ISO-NE locational forward reserve auction for the summer 2010 period (June 1, 2010 September 30, 2010). Because the units were not available to the ISO-NE by June 1, 2010 and GenConn did not have or procure replacement capacity to meet its full reserve obligation, GenConn was assessed ISO-NE penalties for the difference between the cleared GenConn Devon capacity and the facility s available capacity. NRG s share of such penalties was not material.

In April 2009, GenConn Energy closed on $534 million of project financing related to these projects. The project financing includes a seven-year project backed term loan and a five-year working capital facility which together total $291 million. In addition, NRG and United Illuminating have each closed an equity bridge loan of $121.5 million, which together total $243 million. NRG is funding its share of costs related to these projects via draw downs on the equity bridge loan totaling $115 million as of June 30, 2010. GenConn began to draw on the project financing facility to cover costs related to the Devon project in August 2009 and the Middletown project in June 2010. As of June 30, 2010, $109 million had been drawn.

Retail Development

In 2009, NRG began development of a network operations business to support the large scale deployment of electric vehicles in Houston and elsewhere in the ERCOT market. By 2011, and in coordination with the introduction of multiple plug-in vehicles by the automotive industry, NRG plans to offer a range of integrated products and services that enable both public and home charging of electric vehicles. In conjunction with this effort, NRG announced in November 2009 that it will work with Nissan Motor Co. to make the City of Houston a launch city for the broader use of electric vehicles. In November 2009, NRG announced a joint project with the City of Houston to add plug-in fleet vehicles as well as public charging stations to support them. In March 2010, NRG invested in Aptera Motors, Inc., a privately held electric vehicle, or EV, manufacturer expected to launch a production EV in 2011.

In Mass, Reliant is continuing its development efforts in smart energy by enhancing the products and services that provide energy usage insights, choices and control, and increasing the scale at which we can offer these services. In addition, during the second quarter of 2010, Reliant expanded its product offerings to include non-commodity value added services to both Mass and C&I customers.

Nuclear Innovation North America

NINA, NRG s majority-owned subsidiary, is focused on marketing, siting, developing, financing and investing in new advanced design nuclear projects in select markets across North America, including the planned STP Units 3 and 4 Project. TANE, a wholly-owned subsidiary of Toshiba Corporation, is the minority owner of NINA. Based on its current NRC schedule, the Company expects to achieve commercial operation for Unit 3 in 2016 and commercial operation for Unit 4 approximately 12 months thereafter. The total rated capacity of STP Units 3 and 4 is expected to be approximately 3,000 MW, subject to NRC approval.

The U.S. DOE has confirmed that the STP Units 3 and 4 Project is one of four projects selected for further due diligence and negotiation leading to a conditional commitment under the U.S. DOE loan guarantee program. NINA is currently in discussions with the U.S. DOE on the specific terms and amount to be loaned for the project. NRG believes U.S. DOE loan guarantee support is critical to new nuclear development projects. In addition to U.S. loan guarantees, NINA is seeking to augment potential financial support from the U.S. DOE by actively pursuing additional loan guarantees through the Japanese government.

The likelihood of NINA receiving a loan guarantee is largely dependent upon additional appropriations for nuclear development by Congress or other means of properly securing the necessary funding for additional nuclear loan guarantee volume. See Note 15, *Commitments and Contingencies*, to this Form 10-Q for further discussion.

On March 1, 2010, an agreement was reached with CPS for NINA to acquire a controlling interest in the STP Units 3 and 4 Project through a settlement of the litigation between the parties. See Note 15, *Commitments and Contingencies*, to this Form 10-Q for further discussion.

On April 8, 2010, NINA announced an agreement for the Building and Construction Trades Department, or BCTD, of the AFL-CIO to provide skilled union labor to construct STP Units 3 and 4. The BCTD is an alliance of 13 national and international unions that collectively represent over two million skilled craft professionals in the U.S. and Canada.

On May 10, 2010, NINA and TEPCO Nuclear Energy America LLC, or TNEA, a wholly-owned subsidiary of The Tokyo Electric Power Company of Japan, Inc., signed an Investment and Option Agreement whereby TNEA agreed to acquire up to a 20% interest in NINA Investments Holdings LLC, or Holdings. See Note 15, *Commitments and Contingencies*, to this Form 10-Q for further discussion.

Thermal Acquisition

Northwind Phoenix, LLC On June 22, 2010, NRG, through its wholly-owned subsidiary NRG Thermal LLC, or NRG Thermal, acquired Northwind Phoenix, LLC, or Northwind Phoenix. Northwind Phoenix owns and operates one of the newest district cooling systems in the United States, providing chilled water to commercial buildings in the Phoenix central business district. In addition to the local business district, Northwind Phoenix also maintains and operates Combined Heat and Power, or CHP, plants that provide chilled water, steam and electricity to portions of Arizona State University campuses in Tempe and Mesa, and in metropolitan Tucson, including that city s convention center.

Renewable Development and Acquisitions

As part of its core strategy, NRG intends to invest significantly in the development and acquisition of renewable energy projects, including wind, solar and biomass. NRG s renewable strategy is intended to capitalize on first mover advantage in a high growth segment of our business, the Company s existing regional presence in regions with attractive renewable resources and the prevalence, in the Company s core markets, of state-mandated renewable portfolio standards. The Company s renewable projects tend to be smaller and more numerous than its conventional utility-sized projects. As a result, a brief description of the Company s development efforts in respect of each renewable technology follows.

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Solar

NRG is developing a number of solar projects utilizing photovoltaic, or PV, as well as solar thermal technologies. Specifically, NRG has projects that have entered into off-take arrangements with Southern California Edison, Pacific Gas & Electric, El Paso Electric, and Tucson Electric Power, each of which will utilize either PV, or solar thermal. While each of these projects has a PPA in place, the development of these projects is subject to certain regulatory approvals, conditions and milestones which may affect the Company s decision to pursue further development of one or more of these projects.

Consistent with its business strategy, NRG is currently focused on early stage development efforts in a number of markets as well as conducting due diligence with respect to various equity investment opportunities for solar projects utilizing solar technologies that range from concentrated solar thermal to PV. In June 2010, NRG acquired a 450 MW pipeline of solar development projects from US Solar Ventures, an affiliate of Arclight Capital Partners, LLC. These development projects, which range in size from 20 MW to 99 MW, and have the potential to be operational between 2011 and 2013, do not at present have PPAs but they have site control and interconnection rights which NRG deems to be very valuable. This acquisition increases NRG s solar projects under development to 1,150 MW.

NRG s efforts to date have focused on larger (by renewable standards) utility sized solar projects. However, the Company does intend to be involved, to at least some degree, in smaller scale distributed solar in one or more of its core domestic markets.

Wind

Terrestrial Wind

On June 14, 2010, NRG acquired South Trent Wind LLC, owner of the South Trent wind farm, or South Trent, a 101 MW wind farm near Sweetwater, Texas. South Trent commenced operations in January 2009 and consists of 44 turbines producing up to 2.3 MW of power each. The project has a 20-year PPA which commenced in January 2009 for all generation from the site.

Offshore Wind

On April 26, 2010, the U.S. Department of Interior through its newly created Bureau of Ocean Energy Management, Regulation and Enforcement issued a request for interest, or RFI, in obtaining one or more commercial leases for the construction of a wind energy project on the Outer Continental Shelf off the coast of Delaware. The RFI process will determine if there is competitive interest in building on an ocean tract starting 7.5 miles due east of Rehoboth Beach, Delaware. NRG Bluewater Holdings LLC, or NRG Bluewater, plans to build the Mid-Atlantic Wind Park in an area inside this zone 13 miles from shore, running to more than 20 miles from shore for the farthest turbine. On June 25, 2010, NRG Bluewater, through its subsidiary Bluewater Wind Delaware LLC filed a response to the RFI.

Biomass

In April 2010, the Company was awarded a 10-year contract from the New York State Energy Research and Development Authority for power generated using renewable biomass fuel at its Dunkirk Generating Station in western New York. The project will produce up to 15 MW of the station s total output by co-firing with clean wood biomass. The award was part of a competitive solicitation to award contracts for projects that deliver renewable energy to the New York wholesale power market and which will help the state reach its RPS goal to increase the proportion of renewable electricity sold in New York from 25 percent to 30 percent by 2015.

In addition to the Dunkirk project, NRG has a biomass project under development at its Montville Generating Station. The project would involve the repowering one of the facility s existing units to produce up to 40 MW of electricity from locally sourced biomass. The project has received approval from the Connecticut Siting Council, and in April 2010 was awarded an air permit from the Connecticut Department of Environmental Protection. The Company is pursuing opportunities to sell the power on the New England power grid which will also help the state toward reaching its goal of 20 percent of electricity in the state generated by a Class-1 fuel source.

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Off-Balance Sheet Arrangements

Obligations under Certain Guarantee Contracts

NRG and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Note 26, *Guarantees,* to the Company s 2009 Form 10-K for additional discussion.

Retained or Contingent Interests

NRG does not have any material retained or contingent interests in assets transferred to an unconsolidated entity.

Derivative Instrument Obligations

The Company s 3.625% Preferred Stock includes a feature which is considered an embedded derivative per ASC 815. Although it is considered an embedded derivative, it is exempt from derivative accounting as it is excluded from the scope pursuant to ASC 815. As of June 30, 2010, based on the Company s stock price, the embedded derivative was out-of-the-money and had no redemption value.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable Interest in Equity Investments As of June 30, 2010, NRG has several investments with an ownership interest percentage of 50% or less in energy and energy-related entities that are accounted for under the equity method of accounting. Two of these investments, GenConn Energy LLC and Sherbino, are variable interest entities for which NRG is not the primary beneficiary.

NRG s pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $126 million as of June 30, 2010. This indebtedness may restrict the ability of these subsidiaries to issue dividends or distributions to NRG.

Contractual Obligations and Commercial Commitments

NRG has a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to the Company s capital expenditure programs, as disclosed in the Company s Annual Report on Form 10-K for the year ended December 31, 2009. Also see Note 15, *Commitments and Contingencies*, to this Form 10-Q for a discussion of new commitments and contingencies that also include contractual obligations and commercial commitments that occurred during the six months ended June 30, 2010.

Critical Accounting Policies and Estimates

NRG s discussion and analysis of the financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements and related disclosures in compliance with generally accepted accounting principles, or GAAP, requires the application of appropriate technical accounting rules and guidance as well as the use of estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects and legal and regulatory challenges. These judgments, in and of themselves, could materially affect the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment may also have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies have not changed.

On an ongoing basis, NRG evaluates these estimates, utilizing historic experience, consultation with experts and other methods the Company considers reasonable. In any event, actual results may differ substantially from the Company s estimates. Any effects on the Company s business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Critical accounting policies and estimates are the accounting policies that are most important to the portrayal of NRG s financial condition and results of operations and require management s most difficult, subjective or complex judgment. NRG s critical accounting policies include derivative accounting, income taxes and valuation allowance for deferred taxes, evaluation of assets for impairment and other than temporary decline in value, goodwill and other intangible assets, contingencies and accounting for unbilled revenues.

As described in *Critical Accounting Policies and Estimates Goodwill and Other Intangible Assets,* in the Company s Annual Report on Form 10-K for the year ended December 31, 2009, the Company believes that assumptions about future power prices most significantly impact the fair value of its Texas reporting unit. The price of natural gas plays an important role in setting the price of electricity in many of the regions where NRG operates power plants, and forward natural gas prices have continued to decline since year-end 2009. At December 31, 2009, the Company estimated the fair value of NRG Texas invested capital to exceed its carrying value by approximately 25%. Assuming all other factors held constant, a hypothetical $1 drop in the Company s long-term natural gas price view used in that estimate would not have caused the fair value of NRG Texas to fall below its carrying value, but would have significantly reduced the excess fair value over carrying value. If long-term natural gas prices remain depressed or continue to drop for an extended period of time, the Company s goodwill may become impaired in the future, which would result in a charge against earnings.

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ITEM 3 QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

NRG is exposed to several market risks in the Company s normal business activities. Market risk is the potential loss that may result from market changes associated with the Company s merchant power generation or with an existing or forecasted financial or commodity transaction. The types of market risks the Company is exposed to are commodity price risk, interest rate risk, liquidity risk, credit risk, and currency exchange risk. In order to manage these risks, the Company uses various fixed-price forward purchase and sales contracts, futures and option contracts traded on the New York Mercantile Exchange, and swaps and options traded in the over-the-counter financial markets to:

- Manage and hedge fixed-price purchase and sales commitments;
- Manage and hedge exposure to variable rate debt obligations;
- Reduce exposure to the volatility of cash market prices; and
- Hedge fuel requirements for the Company s generating facilities.

Commodity Price Risk

Commodity price risks result from exposures to changes in spot prices, forward prices, volatilities, and correlations between various commodities, such as natural gas, electricity, coal, oil, and emissions credits. A number of factors influence the level and volatility of prices for energy commodities and related derivative products. These factors include:

- Seasonal, daily and hourly changes in demand;
- Extreme peak demands due to weather conditions;
- Available supply resources;
- Transportation availability and reliability within and between regions; and
- Changes in the nature and extent of federal and state regulations.

NRG s portfolio consists of generation assets and wholesale transactions load serving obligations. NRG manages the commodity price risk of the Company s merchant generation operations and load serving obligations by entering into various derivative or non-derivative instruments to hedge the variability in future cash flows from forecasted sales and purchases of electricity and fuel. These instruments include forwards, futures, swaps, and option contracts traded on various exchanges, such as New York Mercantile Exchange, or NYMEX, and Intercontinental Exchange, or ICE, as well as over-the-counter financial markets. The portion of forecasted transactions hedged may vary based upon management s assessment of market, weather, the projected operations of the Company s generation assets and other factors.

While some of the contracts the Company uses to manage risk represent commodities or instruments for which prices are available from external sources, other commodities and certain contracts are not actively traded and are valued using other pricing sources and modeling techniques to determine expected future market prices, contract quantities, or both. NRG uses the Company s best estimates to determine the fair value of those derivative contracts. However, it is likely that future market prices could vary from those used in recording mark-to-market derivative instrument valuation, and such variations could be material.

NRG measures the risk of the Company s portfolio using several analytical methods, including sensitivity tests, scenario tests, stress tests, position reports, and Value at Risk, or VaR. VaR is a statistical model that attempts to predict risk of loss based on market price and volatility. Currently, the company estimates VaR using a Monte Carlo simulation based methodology.

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NRG uses a diversified VaR model to calculate an estimate of the potential loss in the fair value of the Company s energy assets and liabilities, which includes generation assets, load obligations, and bilateral physical and financial transactions. The key assumptions for the Company s diversified model include: (i) a lognormal distribution of prices; (ii) one-day holding period; (iii) a 95% confidence interval; (iv) a rolling 36-month forward looking period; and (v) market implied volatilities and historical price correlations.

As of June 30, 2010, the VaR for NRG s commodity portfolio, including generation assets, load obligations and bilateral physical and financial transactions calculated using the diversified VaR model was $51 million.

The following table summarizes average, maximum and minimum VaR for NRG for the three and six months ended June 30, 2010, and 2009:

(In millions)	**2010**	**2009**
VaR as of June 30	$51	$49
Three months ended June 30:		
Average	$58	$35
Maximum	70	54
Minimum	46	28
Six months ended June 30:		
Average	$53	$38
Maximum	70	54
Minimum	37	28

Due to the inherent limitations of statistical measures such as VaR, the evolving nature of the competitive markets for electricity and related derivatives, and the seasonality of changes in market prices, the VaR calculation may not capture the full extent of commodity price exposure. As a result, actual changes in the fair value of mark-to-market energy assets and liabilities could differ from the calculated VaR, and such changes could have a material impact on the Company s financial results.

In order to provide additional information for comparative purposes to NRG s peers, the Company also uses VaR to estimate the potential loss of derivative financial instruments that are subject to mark-to-market accounting. These derivative instruments include transactions that were entered into for both asset management and trading purposes. The VaR for the derivative financial instruments calculated using the diversified VaR model as of June 30, 2010, for the entire term of these instruments entered into for both asset management and trading, was approximately $21 million primarily driven by asset-backed transactions.

Interest Rate Risk

NRG is exposed to fluctuations in interest rates through the Company s issuance of fixed rate and variable rate debt. Exposures to interest rate fluctuations may be mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to interest rate volatility and result in primarily fixed rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. NRG s risk management policies allow the Company to reduce interest rate exposure from variable rate debt obligations.

In May 2009, NRG entered into a series of forward-starting interest rate swaps. These interest rate swaps become effective on April 1, 2011, and are intended to hedge the risks associated with floating interest rates. For each of the interest rate swaps, the Company will pay its counterparty the equivalent of a fixed interest payment on a predetermined notional value, and NRG receives the monthly equivalent of a floating interest payment based on a 1-month LIBOR calculated on the same notional value. All interest rate swap payments by NRG and its counterparties are made monthly and the LIBOR is determined in advance of each interest period. The total notional amount of these swaps is $900 million. The swaps mature on February 1, 2013.

In June 2010, in connection with the Blythe and South Trent financing transactions (see Note 8, *Long-Term Debt*), the Company entered into a series of current and forward-starting interest rate swaps, intended to hedge the risks associated with floating interest rates. These swaps, which have a combined notional value of $103 million, mature on various dates through 2028.

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As of June 30, 2010, the Company had various interest rate swap agreements with notional amounts totaling approximately $3.2 billion. If the swaps had been discontinued on June 30, 2010, the Company would have owed the counterparties approximately $110 million. Based on the investment grade rating of the counterparties, NRG believes its exposure to credit risk due to nonperformance by counterparties to its hedge contracts to be immaterial.

NRG has both long- and short-term debt instruments that subject the Company to the risk of loss associated with movements in market interest rates. As of June 30, 2010, a 1% change in interest rates would result in a $12 million change in interest expense on a rolling twelve month basis.

As of June 30, 2010, the Company s long-term debt fair value was $8 billion and the carrying amount was $8.1 billion. NRG estimates that a 1% decrease in market interest rates would have increased the fair value of the Company s long-term debt by $419 million.

Liquidity Risk

Liquidity risk arises from the general funding needs of NRG s activities and in the management of the Company s assets and liabilities. NRG s liquidity management framework is intended to maximize liquidity access and minimize funding costs. Through active liquidity management, the Company seeks to preserve stable, reliable and cost-effective sources of funding. This enables the Company to replace maturing obligations when due and fund assets at appropriate maturities and rates. To accomplish this task, management uses a variety of liquidity risk measures that take into consideration market conditions, prevailing interest rates, liquidity needs, and the desired maturity profile of liabilities. The Company is currently exposed to additional collateral posting if natural gas prices decline primarily due to the long natural gas equivalent position at various exchanges used to hedge NRG s retail supply load obligations.

Based on a sensitivity analysis for power and gas positions under marginable contracts, a $1 per MMBtu change in natural gas prices across the term of the marginable contracts would cause a change in margin collateral posted of approximately $155 million as of June 30, 2010, and a 0.25 MMBtu/MWh change in heat rates for heat rate positions would result in a change in margin collateral posted of approximately $28 million as of June 30, 2010. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of June 30, 2010.

Under the second lien, NRG is required to post certain letters of credit as credit support for changes in commodity prices. As of June 30, 2010, no letters of credit are outstanding to second lien counterparties. With changes in commodity prices, the letters of credit could grow to $64 million, the cap under the agreements.

Credit Risk

Credit risk relates to the risk of loss resulting from non-performance or non-payment by counterparties pursuant to the terms of their contractual obligations. NRG is exposed to counterparty credit risk through various activities including wholesale sales, fuel purchases and retail supply and retail customer credit risk through its retail load activities.

Counterparty Credit Risk

The Company monitors and manages counterparty credit risk through credit policies that include: (i) an established credit approval process; (ii) a daily monitoring of counterparties credit limits; (iii) the use of credit mitigation measures such as margin, collateral, credit derivatives or prepayment arrangements; (iv) the use of payment netting agreements; and (v) the use of master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. The Company seeks to mitigate counterparty credit risk with a diversified portfolio of counterparties. The Company also has credit protection within various agreements to call on additional collateral support if and when necessary. Cash margin is collected and held at NRG to cover the credit risk of the counterparty until positions settle.

As of June 30, 2010, total counterparty credit exposure to substantially all counterparties was $1.5 billion and NRG held cash collateral against those positions of $310 million resulting in a net exposure of $1.2 billion. Total counterparty credit exposure is discounted at the risk free rate.

The following table highlights the credit quality and the net counterparty credit exposure by industry sector. Net counterparty credit exposure is defined as the aggregate net asset position for NRG with counterparties where netting is permitted under the enabling agreement and includes all cash flow, mark-to-market and NPNS, and non-derivative transactions. The exposure is shown net of collateral held, includes amounts net of receivables or payables.

Category	Net Exposure[(a)] (% of Total)
Financial institutions	59%
Utilities, energy, merchants, marketers and other	31
Coal suppliers	4
ISOs	6
Total as of June 30, 2010	100%

Category	Net Exposure[(a)] (% of Total)
Investment grade	88%
Non-Investment grade	2
Non-rated	10
Total as of June 30, 2010	100%

(a) Counterparty credit exposure excludes California tolling, Northeast load obligations, certain cooperative load contracts, and Texas Westmoreland coal contracts. The aforementioned exposures were excluded for various reasons including regulatory support or liens

held against the contracts which serve to reduce the risk of loss. NRG also excludes uranium and coal transportation contracts from counterparty credit exposure because of the illiquidity of the reference markets. Credit exposure also excludes any exposure NRG has to counterparties of non-recourse subsidiaries.

NRG has counterparty credit risk exposure to certain counterparties representing more than 10% of total net exposure and the aggregate of such counterparties was $409 million. Approximately 89% of NRG s positions relating to credit risk roll-off by the end of 2012. Changes in hedge positions and market prices will affect credit exposure and counterparty concentration. Given the credit quality, diversification and term of the exposure in the portfolio, NRG does not anticipate a material impact on the Company s financial results from nonperformance by any of NRG s counterparties.

Retail Customer Credit Risk

NRG is exposed to retail credit risk through the Company s competitive electricity supply business, which serves C&I customers and the Mass market in Texas. Retail credit risk results when a customer fails to pay for services rendered. The losses could be incurred from nonpayment of customer accounts receivable and any in-the-money forward value. NRG manages retail credit risk through the use of established credit policies that include monitoring of the portfolio, and the use of credit mitigation measures such as deposits or prepayment arrangements.

As of June 30, 2010, the Company s retail customer credit exposure to C&I customers was diversified across many customers and various industries, with a significant portion of the exposure with government entities.

NRG is also exposed to retail customer credit risk relating to its Mass customers, which may result in a write-off of bad debt. During 2010, the Company continued to experience improved customer payment behavior, but current economic conditions may affect the Company s customers ability to pay bills in a timely manner, which could increase customer delinquencies and may lead to an increase in bad debt expense.

Credit Risk Contingent Features

Certain of the Company s hedging agreements contain provisions that require the Company to post additional collateral if the counterparty determines that there has been deterioration in credit quality, generally termed adequate assurance under the agreements or require the Company to post additional collateral if there was a one notch downgrade in the Company s credit rating. The collateral required for contracts that have adequate assurance clauses that are in a net liability position as of June 30, 2010, was $63 million. The collateral required for contracts with credit rating contingent features that are in a net liability position as of June 30, 2010, was $11 million. The Company is also a party to certain marginable agreements where NRG has a net liability position but the counterparty has not called for the collateral due, which is approximately $15 million as of June 30, 2010.

Fair Value of Derivative Instruments

NRG may enter into long-term power purchase and sales contracts, fuel purchase contracts and other energy-related financial instruments to mitigate variability in earnings due to fluctuations in spot market prices and to hedge fuel requirements at generation facilities. In addition, in order to mitigate interest rate risk associated with the issuance of the Company s variable rate and fixed rate debt, NRG enters into interest rate swap agreements.

NRG s trading activities are subject to limits within the Company s Risk Management Policy. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings.

The tables below disclose the activities that include both exchange and non-exchange traded contracts accounted for at fair value in accordance with ASC-820, *Fair Value Measurements and Disclosures*, or ASC 820. Specifically, these tables disaggregate realized and unrealized changes in fair value; disaggregate estimated fair values at June 30, 2010, based on their level within the fair value hierarchy defined in ASC 820; and indicate the maturities of contracts at June 30, 2010.

Derivative Activity Gains/(Losses)	**(In millions)**
Fair value of contracts as of December 31, 2009	$ 459
Contracts realized or otherwise settled during the period	(149)
Changes in fair value	483
Fair value of contracts as of June 30, 2010	$ 793

	Fair Value of Contracts as of June 30, 2010				
(In millions) **Fair value hierarchy gains/(losses)**	**Maturity Less Than 1 Year**	**Maturity 1-3 Years**	**Maturity 4-5 Years**	**Maturity in Excess 4-5 Years**	**Total Fair Value**
Level 1	$ 14	$ (46)	$(20)	$	$ (52)
Level 2	386	499	76	(40)	921
Level 3	(84)	(3)	11		(76)
Total	$316	$450	$ 67	$(40)	$793

A small portion of NRG s contracts are exchange-traded contracts with readily available quoted market prices. The majority of NRG s contracts are non-exchange-traded contracts valued using prices provided by external sources, primarily price quotations available through brokers or over-the-counter and on-line exchanges. For the majority of NRG markets, the Company receives quotes from multiple sources. To the extent that NRG receives multiple quotes, the Company s prices reflect the average of the bid-ask mid-point prices obtained from all sources that NRG believes provide the most liquid market for the commodity. If the Company receives one quote then the mid point of the bid-ask spread for that quote is used. The terms for which such price information is available vary by commodity, region and product. A significant portion of the fair value of the Company s derivative portfolio is based on price quotes from brokers in active markets who regularly facilitate the Company s transactions and the Company believes such price quotes are executable. The Company does not use third party sources that derive price based on proprietary models or market surveys. The remainder of the assets and liabilities represents contracts for which external sources or observable market quotes are not available. These contracts are valued based on various valuation techniques including but not limited to internal models based on a fundamental analysis of the market and extrapolation of observable market data with similar characteristics. Contracts valued with prices provided by models and other valuation techniques make up 10% of the total fair value of all derivative contracts. The fair value of each contract is discounted using a risk free interest rate. In addition, the Company applies a credit reserve to reflect credit risk which is calculated based on published default probabilities. To the extent that NRG s net exposure after cash collateral paid/received under a specific master agreement is an asset, the Company calculates credit reserve applying the counterparty s default swap rate. If the net exposure after cash collateral paid/received under a specific master agreement is a liability, the Company calculates credit reserve applying NRG s default swap rate. The credit reserve is added to the discounted fair value to reflect the exit price that a market participant would be willing to receive to assume NRG s liabilities or that a market participant would be willing to pay for NRG s assets. As of June 30, 2010, the credit reserve resulted in a $11 million decrease in fair value which is composed of a $6 million loss in OCI and a $5 million loss in derivative revenue and cost of operations.

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The fair values in each category reflect the level of forward prices and volatility factors as of June 30, 2010, and may change as a result of changes in these factors. Management uses its best estimates to determine the fair value of commodity and derivative contracts NRG holds and sells. These estimates consider various factors including closing exchange and over-the-counter price quotations, time value, volatility factors and credit exposure. It is possible; however, that future market prices could vary from those used in recording assets and liabilities from energy marketing and trading activities and such variations could be material.

The Company has elected to disclose derivative assets and liabilities on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. Also, collateral received or paid on the Company s derivative assets or liabilities are recorded on a separate line item on the balance sheet. Consequently, the magnitude of the changes in individual current and non-current derivative assets or liabilities is higher than the underlying credit and market risk of the Company s portfolio. As discussed in Item 6A *Quantitative and Qualitative Disclosures about Market Risk, Commodity Price Risk* in the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2009, NRG measures the sensitivity of the Company s portfolio to potential changes in market prices using VaR, a statistical model which attempts to predict risk of loss based on market price and volatility. NRG s Risk Management Policy places a limit on one-day holding period VaR, which limits the Company s net open position. As the Company s trade-by-trade derivative accounting results in a gross-up of the Company s derivative assets and liabilities, the net derivative assets and liability position is a better indicator of NRG s hedging activity. As of June 30, 2010, NRG s net derivative asset was $793 million, an increase to total fair value of $334 million as compared to December 31, 2009. This increase was primarily driven by the decreases in gas and power prices and the roll-off of trades that settled during the period.

Based on a sensitivity analysis, the impact of a $1 per MMBtu increase or decrease in natural gas prices across the term of the derivative contracts would cause a change of approximately $299 million in the net value of derivatives as of June 30, 2010.

Currency Exchange Risk

NRG may be subject to foreign currency exchange risk as a result of the Company entering into purchase commitments with foreign vendors for the purchase of major equipment associated with *Repowering*NRG initiatives. To reduce the risks to such foreign currency exposure, the Company may enter into transactions to hedge its foreign currency exposure using currency options and forward contracts. As of June 30, 2010, there were no foreign currency options or forward contracts outstanding for purchase commitments. As a result of the Company s limited foreign currency exposure to date, the effect of foreign currency fluctuations has not been material to the Company s results of operations, financial position and cash flows as of and for the six months ended June 30, 2010.

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ITEM 4 CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of NRG s management, including its principal executive officer, principal financial officer and principal accounting officer, NRG conducted an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Based on this evaluation, the Company s principal executive officer, principal financial officer and principal accounting officer concluded that the disclosure controls and procedures were effective as of the end of the period covered by this report on Form 10-Q.

Changes in Internal Control over Financial Reporting

There were no changes in the Company s internal controls over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act) that occurred in the second quarter of 2010 that materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Inherent Limitations over Internal Controls

NRG s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. However, internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations, including the possibility of human error and circumvention by collusion or overriding of controls. Accordingly, even an effective internal control system may not prevent or detect material misstatements on a timely basis. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

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PART II OTHER INFORMATION

ITEM 1 LEGAL PROCEEDINGS

For a discussion of material legal proceedings in which NRG was involved through June 30, 2010, see Note 15, *Commitments and Contingencies*, to the condensed consolidated financial statements of this Form 10-Q.

ITEM 1A RISK FACTORS

Information regarding risk factors appears in Part I, Item 1A, *Risk Factors Related to NRG Energy, Inc.* in NRG Energy, Inc. s Annual Report on Form 10-K for the fiscal year ended December 31, 2009.

ITEM 2 UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

For the period ended June 30, 2010	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Dollar value of shares that may be purchased under the 2010 Capital Allocation Plan
First quarter 2010		$		$ 180,000,000
April 1 April 30				180,000,000
May 1 May 31	800,500	21.17	800,500	162,244,791
June 1 June 30	1,413,500	22.80	1,413,500	130,002,304
Second quarter 2010 Total	2,214,000	22.57	2,214,000	130,002,304
Year-to-date	2,214,000	$ 22.57	2,214,000	$ 130,002,304

On February 23, 2010, the Company announced a plan to repurchase $180 million of common stock under the Company s 2010 Capital Allocation Plan. The Company repurchased $50 million of common stock during the period ended June 30, 2010. NRG intends to complete its $180 million of share repurchases by the end of 2010, subject to market prices, financial restrictions under the Company s debt facilities and as permitted by securities laws.

ITEM 3 DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4 (REMOVED AND RESERVED)

ITEM 5 OTHER INFORMATION

None.

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ITEM 6 EXHIBITS

Exhibits

4.1	Twenty-Eighth Supplemental Indenture, dated as of April 16, 2010, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (1)
4.2	Twenty-Ninth Supplemental Indenture, dated as of April 16, 2010, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (1)
4.3	Thirtieth Supplemental Indenture, dated as of April 16, 2010, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (1)
4.4	Thirty-First Supplemental Indenture, dated as of April 16, 2010, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (1)
4.5	Thirty-Second Supplemental Indenture, dated as of June 23, 2010, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (2)
4.6	Thirty-Third Supplemental Indenture, dated as of June 23, 2010, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (2)
4.7	Thirty-Fourth Supplemental Indenture, dated as of June 23, 2010, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (2)
4.8	Thirty-Fifth Supplemental Indenture, dated as of June 23, 2010, among NRG Energy, Inc., the existing guarantors named therein, the guaranteeing subsidiaries named therein and Law Debenture Trust Company of New York. (2)
10.1	Chief Financial Officer Compensation Table for 2010. (3)
10.2	2009 Executive Change-in-Control and General Severance Plan. (3)
10.3*	Investment and Option Agreement by and among Nuclear Innovation North America LLC, Nuclear Innovation North America Investments Holdings LLC and TEPCO Nuclear Energy America LLC, dated as of May 10, 2010, filed herewith.
10.4*	Parent Company Agreement by and among NRG Energy, Inc., Nuclear Innovation North America LLC, TEPCO and TEPCO Nuclear Energy America LLC, dated as of May 10, 2010, filed herewith.
10.5	Third Amended and Restated Credit Agreement, dated as of June 30, 2010. (4)
10.6(a)	Letter of Credit and Reimbursement Agreement, dated as of June 30, 2010. (4)

10.6(b)	Letter of Credit and Reimbursement Agreement, dated as of June 30, 2010. (4)
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
31.3	Certification of Chief Accounting Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
32	Certification of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, filed herewith.

(1) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on April 21, 2010.

(2) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on June 29, 2010.

(3) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on April 1, 2010.

(4) Incorporated herein by reference to NRG Energy, Inc. s current report on Form 8-K filed on July 1, 2010.

* Portions of this exhibit have been redacted and are subject to a confidential treatment request filed with the Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended.

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SIGNATURES

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.

NRG ENERGY, INC.
(Registrant)

/s/ DAVID W. CRANE
David W. Crane
Chief Executive Officer
(Principal Executive Officer)

/s/ CHRISTIAN S. SCHADE
Christian S. Schade
Chief Financial Officer
(Principal Financial Officer)

/s/ JAMES J. INGOLDSBY
James J. Ingoldsby
Chief Accounting Officer
(Principal Accounting Officer)

Date: August 2, 2010

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