NRG ENERGY, INC.
Form 10-Q
October 30, 2008

Table of Contents

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**
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
	For the quarterly period ended: September 30, 2008

Commission File Number: 001-15891

NRG Energy, Inc.
(Exact name of Registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**41-1724239** *(I.R.S. Employer Identification No.)*
211 Carnegie Center Princeton, New Jersey *(Address of principal executive offices)*	**08540** *(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 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 is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer, and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o 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 Section 12, 13 or 15(d) of the Securities and Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court.

Yes þ No o

As of October 23, 2008, there were 233,047,222 shares of common stock outstanding, par value $0.01 per share.

TABLE OF CONTENTS

Index

Table of Contents

CAUTIONARY STATEMENT REGARDING FORWARD LOOKING INFORMATION

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. The words believes , projects , anticipates , plans , expects , estimates and similar expressions are intended to identify forward-looking 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 Related to NRG in Part I, Item 1A, of the Company s Annual Report on Form 10-K, for the year ended December 31, 2007, including the following:

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

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 independent system operators, or ISOs, or regional transmission organizations, 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 units and wind projects;

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

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

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.

Table of Contents

GLOSSARY OF TERMS

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

Acquisition	February 2, 2006 acquisition of Texas Genco LLC, now referred to as the Company s Texas region
ABWR	Advanced Boiling Water Reactor
ANPR	Advanced Notice of Proposed Rulemaking
ARO	Asset Retirement Obligation
BACT	Best Available Control Technology
Baseload Capacity	Electric power generation capacity normally expected to serve loads on an around-the-clock basis throughout the calendar year
BP	BP Alternative Energy North America Inc.
BTU	British Thermal Unit
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CDWR	California Department of Water Resources
CL&P	Connecticut Light & Power
CO_2	Carbon dioxide
COLA	Combined Operating License Application
CS	Credit Suisse Group
CSF I	NRG Common Stock Finance I LLC
CSF II	NRG Common Stock Finance II LLC
DNREC	Delaware Department of Natural Resources
DPUC	Connecticut Department of Public Utility Control
EFOR	Equivalent Forced Outage Rates considers the equivalent impact that forced de-ratings have in addition to full forced outages
EPC	Engineering, Procurement and Construction
ERCOT	Electric Reliability Council of Texas, the Independent System Operator and the regional reliability coordinator of the various electricity systems within Texas
ESPP	Employee Stock Purchase Plan
Exchange Act	The Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board, the designated organization for establishing standards for financial accounting and reporting
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIN 48	FIN 48, *Accounting for Uncertainty in Income Taxes*
FSP	FASB Staff Position
GHG	Greenhouse Gases
IGCC	Integrated Gasification Combined Cycle
ISO	Independent System Operator, also referred to as Regional Transmission Organization, or RTO
ISO-NE	ISO New England, Inc.
ITISA	Itiquira Energetica S.A.

kW	Kilowatts
kWh	Kilowatt-hours
LFRM	Locational Forward Reserve Market
LIBOR	London Inter-Bank Offer Rate
LMP	Locational Marginal Prices
LTIP	Long-Term Incentive Plan
MACT	Maximum Achievable Control Technology
Merit Order	A term used for the ranking of power stations in terms of increasing order of fuel costs
MMBtu	Million British Thermal Units
MOU	Memorandum of Understanding

GLOSSARY OF TERMS (cont d)

MRTU	Market Redesign and Technology Upgrade
MW	Megawatts
MWh	Saleable megawatt hours net of internal/parasitic load megawatt-hours
NAAQS	National Ambient Air Quality Standard
NEPOOL	New England Power Pool
Net Exposure	Counterparty credit exposure to NRG, net of collateral
NiMo	Niagara Mohawk Power Corporation
NINA	Nuclear Innovation North America LLC
NOx	Nitrogen oxide
NOL	Net Operating Loss
NOV	Notice of Violation
NPNS	Normal Purchase Normal Sale
NRC	Nuclear Regulatory Commission
NYISO	New York Independent System Operator
NYPA	New York Power Authority
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
PMI	NRG Power Marketing LLC, a wholly-owned subsidiary of NRG which procures transportation and fuel for the Company s generation facilities, sells the power from these facilities, and manages all commodity trading and hedging for NRG
PPA	Power Purchase Agreement
PPM	Parts per Million
PSD	Prevention of Significant Deterioration
PUCT	The Public Utility Commission of Texas
Repowering	Replacing, rebuilding, or redeveloping 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 over the next decade
Revolving Credit Facility	NRG s $1 billion senior secured credit facility which matures on February 2, 2011
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must-Run
RPM	Reliability Pricing Model term for capacity market in PJM market
RTO	Regional Transmission Organization, also referred to as an Independent System Operator, or ISO
Sarbanes-Oxley	Sarbanes-Oxley Act of 2002
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 B loan facility and a $1.3 billion Letter of Credit Facility which mature on February 1, 2013, and a $1 billion Revolving Credit Facility, which matures on February 2, 2011
Senior Notes	The Company s $4.7 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 and $1.1 billion of 7.375% senior notes due 2017
SFAS	Statement of Financial Accounting Standards issued by the FASB
SFAS 109	SFAS No. 109, *Accounting for Income Taxes*
SFAS 133	SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*
SFAS 141R	SFAS No. 141 (revised 2007), *Business Combinations*
SFAS 157	SFAS No. 157, *Fair Value Measurements*

Table of Contents

GLOSSARY OF TERMS (cont d)

SFAS 160	SFAS No. 160, *Noncontrolling Interest in Consolidated Financial Statements*
SFAS 161	SFAS No. 161, *Disclosure about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*
Sherbino	Sherbino I Wind Farm LLC
SO_2	Sulfur dioxide
SOP	Statement of Position issued by the American Institute of Certified Public Accountants
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
Synthetic Letter of Credit Facility	NRG s $1.3 billion senior secured synthetic letter of credit facility which matures on February 1, 2013
Term B loan	A senior first priority secured term loan which matures on February 1, 2013, and is included as part of NRG s Senior Credit Facility
Texas Genco	Texas Genco LLC, now referred to as the Company s Texas region
Texas West	The West Zone of Texas ERCOT power market
Tosli	Tosli Acquisition B.V.
US	United States of America
USEPA	United States Environmental Protection Agency
US GAAP	Accounting principles generally accepted in the United States
VAR	Value at Risk
WCP	WCP (Generation) Holdings, LLC

Table of Contents

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 September 30		Nine Months Ended September 30	
(In millions, except for per share amounts)	**2008**	**2007**	**2008**	**2007**
Operating Revenues				
Total operating revenues	$ 2,690	$ 1,772	$ 5,308	$ 4,607
Operating Costs and Expenses				
Cost of operations	997	939	2,812	2,560
Depreciation and amortization	156	160	478	481
General and administrative	75	78	233	234
Development costs	13	49	29	108
Total operating costs and expenses	1,241	1,226	3,552	3,383
Gain on sale of assets				16
Operating Income	1,449	546	1,756	1,240
Other Income/(Expense)				
Equity in earnings of unconsolidated affiliates	58	19	35	40
Other (loss)/income, net	(7)	14	14	44
Refinancing expense				(35)
Interest expense	(186)	(169)	(481)	(520)
Total other expense	(135)	(136)	(432)	(471)
Income From Continuing Operations Before Income Taxes	1,314	410	1,324	769
Income tax expense	530	145	531	300
Income From Continuing Operations	784	265	793	469
		3	172	13

Income from discontinued operations, net of income tax expense								
Net Income		784		268		965		482
Dividends for preferred shares		13		13		41		41
Income Available for Common Stockholders	$	771	$	255	$	924	$	441
Weighted average number of common shares outstanding basic		235		239		236		241
Income from continuing operations per weighted average common share basic	$	3.28	$	1.05	$	3.19	$	1.78
Income from discontinued operations per weighted average common share basic				0.02		0.73		0.05
Net Income per Weighted Average Common Share Basic	$	3.28	$	1.07	$	3.92	$	1.83
Weighted average number of common shares outstanding diluted		277		285		278		287
Income from continuing operations per weighted average common share diluted	$	2.83	$	0.92	$	2.83	$	1.61
Income from discontinued operations per weighted average common share diluted				0.01		0.62		0.05
Net Income per Weighted Average Common Share Diluted	$	2.83	$	0.93	$	3.45	$	1.66

See notes to condensed consolidated financial statements.

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions, except shares)	September 30, 2008 (unaudited)	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,483	$ 1,132
Restricted cash	32	29
Accounts receivable, less allowance for doubtful accounts of $3 and $1, respectively	531	482
Inventory	456	451
Derivative instruments valuation	4,190	1,034
Deferred income taxes		124
Cash collateral paid in support of energy risk management activities	544	85
Prepayments and other current assets	203	174
Current assets discontinued operations		51
Total current assets	7,439	3,562
Property, plant and equipment, net of accumulated depreciation of $2,184 and $1,695, respectively	11,472	11,320
Other Assets		
Equity investments in affiliates	428	425
Notes receivable and capital lease, less current portion	450	491
Goodwill	1,786	1,786
Intangible assets, net of accumulated amortization of $425 and $372, respectively	822	873
Nuclear decommissioning trust fund	333	384
Derivative instruments valuation	816	150
Other non-current assets	134	176
Intangible assets held-for-sale	3	14
Non-current assets discontinued operations		93
Total other assets	4,772	4,392
Total Assets	$ 23,683	$ 19,274

LIABILITIES AND STOCKHOLDERS EQUITY				
Current Liabilities				
Current portion of long-term debt and capital leases	$	122	$	466
Accounts payable		367		384
Derivative instruments valuation		4,022		917
Deferred income taxes		16		
Cash collateral received in support of energy risk management activities		154		14
Accrued expenses and other current liabilities		629		459
Current liabilities discontinued operations				37
Total current liabilities		5,310		2,277
Other Liabilities				
Long-term debt and capital leases		8,059		7,895
Nuclear decommissioning reserve		320		307
Nuclear decommissioning trust liability		252		326
Deferred income taxes		1,083		843
Derivative instruments valuation		1,158		759
Out-of-market contracts		336		628
Other non-current liabilities		568		412
Non-current liabilities discontinued operations				76
Total non-current liabilities		11,776		11,246
Total Liabilities		17,086		13,523
Minority interest		7		
3.625% convertible perpetual preferred stock (at liquidation value, net of issuance costs)		247		247
Commitments and Contingencies				
Stockholders Equity				
Preferred stock (at liquidation value, net of issuance costs)		892		892
Common stock		3		3
Additional paid-in capital		4,135		4,092
Retained earnings		2,194		1,270
Less treasury stock, at cost 29,242,483 and 24,550,600 shares, respectively		(823)		(638)
Accumulated other comprehensive loss		(58)		(115)
Total Stockholders Equity		6,343		5,504
Total Liabilities and Stockholders Equity	$	23,683	$	19,274

See notes to condensed consolidated financial statements.

Table of Contents

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

(In millions) Nine Months Ended September 30,	2008	2007
Cash Flows from Operating Activities		
Net income	$ 965	$ 482
Adjustments to reconcile net income to net cash provided by operating activities Distributions and equity in (earnings) of unconsolidated affiliates	(24)	(23)
Depreciation and amortization	478	483
Amortization of nuclear fuel	31	42
Amortization and write-off of financing costs and debt discount/premiums	22	59
Amortization of intangibles and out-of-market contracts	(226)	(112)
Changes in deferred income taxes and liability for unrecognized tax benefits	427	232
Changes in nuclear decommissioning trust liability	8	23
Changes in derivatives	(110)	41
Changes in collateral deposits supporting energy risk management activities	(320)	(107)
Loss/(gain) on disposals and sales of assets	13	(16)
Gain on sale of discontinued operations	(273)	
Gain on sale of emission allowances	(52)	(31)
Amortization of unearned equity compensation	21	19
Cash provided/(used) by changes in other working capital	81	(116)
Net Cash Provided by Operating Activities	1,041	976
Cash Flows from Investing Activities		
Capital expenditures	(649)	(309)
Increase in restricted cash, net	(3)	(18)
Decrease in notes receivable	20	26
Purchases of emission allowances	(6)	(152)
Proceeds from sale of emission allowances	75	170
Investments in nuclear decommissioning trust fund securities	(441)	(193)
Proceeds from sales of nuclear decommissioning trust fund securities	434	170
Proceeds from sale of discontinued operations, net of cash divested	241	
Proceeds from sale of assets	14	57
Decrease in trust fund balances		19
Equity investment in unconsolidated affiliate	(17)	
Other		(2)
Net Cash Used by Investing Activities	(332)	(232)
Cash Flows from Financing Activities		

Payment of dividends to preferred stockholders	(41)	(41)
Payment of financing element of acquired derivatives	(49)	
Payment for treasury stock	(185)	(268)
Proceeds from issuance of common stock, net of issuance costs	8	
Proceeds from sale of minority interest in subsidiary	50	
Proceeds from issuance of long-term debt	20	1,411
Payment of deferred debt issuance costs	(2)	(5)
Payments for short and long-term debt	(202)	(1,472)
Net Cash Used by Financing Activities	(401)	(375)
Change in cash from discontinued operations	43	(16)
Effect of exchange rate changes on cash and cash equivalents		7
Net Increase in Cash and Cash Equivalents	351	360
Cash and Cash Equivalents at Beginning of Period	1,132	777
Cash and Cash Equivalents at End of Period	$ 1,483	$ 1,137

See notes to condensed consolidated financial statements.

NRG ENERGY, INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

Note 1 Basis of Presentation

NRG Energy, Inc., or NRG, or the Company, is a wholesale power generation company with a significant presence in major competitive power markets in the United States. NRG is engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the trading of energy, capacity and related products in the United States and select international markets.

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 accounting policies NRG follows are set forth 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, 2007. The following notes should be read in conjunction with such policies and other disclosures in the Form 10-K. Interim results are not necessarily indicative of results for a full year.

In the opinion of management, the accompanying unaudited interim 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 September 30, 2008, the results of operations for the three and nine months ended September 30, 2008 and 2007, and cash flows for the nine months ended September 30, 2008 and 2007. 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.

Cash and Cash Equivalents

Cash and cash equivalents at September 30, 2008 are predominantly held in money market funds invested in treasury securities or treasury repurchase agreements.

Investment Accounted for by the Equity Method

In February 2008, a wholly-owned subsidiary of NRG entered into a 50/50 joint venture with a subsidiary of BP Alternative Energy North America Inc., or BP, to build and own the Sherbino I Wind Farm LLC, or Sherbino. This is a 150 MW wind project consisting of 50 Vestas 3 MW wind turbine generators, located in the West Zone of Texas ERCOT power market, or Texas West. The project will be funded through a combination of equity contributions from the owners and non-recourse project-level debt. NRG delivered a $59 million promissory note to Sherbino to support its initial capital contribution, payable no later than December 1, 2008, made an additional $17 million cash contribution in April 2008, and expects to contribute another $11 million by year end, bringing its total expected equity contribution to approximately $87 million. NRG has posted a letter of credit in this amount. NRG s maximum exposure to loss is limited to its expected equity investments. Sherbino commenced commercial operations in October 2008.

Sherbino has entered into a long-term natural gas swap to mitigate a portion of power price risk for its expected power generation. As the changes in natural gas prices and in Texas West power prices do not meet the required correlation for cash flow hedge accounting, Sherbino will account for the natural gas swap hedge under mark-to-market accounting.

NRG accounts for its investment in Sherbino under the equity method of accounting. NRG s share of mark-to-market results of the natural gas swap, a loss of $9 million for the nine months ended September 30, 2008, is included in NRG s equity in earnings of Sherbino. NRG s investment at September 30, 2008, net of its promissory note commitment, is $7 million, which is included in *Equity Investments in Affiliates* on the condensed consolidated balance sheet.

Table of Contents

Other Cash Flow Information

NRG s non-cash investing activities for the nine months ended September 30, 2008 included capital expenditures of $60 million for which the associated liability is reflected within accrued expenses.

Recent Accounting Developments

The Company partially adopted SFAS No. 157, *Fair Value Measurements*, or SFAS 157, on January 1, 2008, delaying application for non-financial assets and non-financial liabilities as permitted. This statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. In February 2008, the Financial Accounting Standards Board, or FASB, issued FASB Staff Position, or FSP, No. FAS 157-1, *Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13*, which amends SFAS 157 to exclude SFAS Statement No. 13, *Accounting for Leases*, or SFAS 13, and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. In February 2008, the FASB also issued FSP No. FAS 157-2, *Effective Date of FASB Statement No. 157*, which permitted delayed application of this statement for non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. The partial adoption of SFAS 157 did not have a material impact on the Company s consolidated financial position, statement of operations, and cash flows. The Company is currently evaluating the impact of the deferred portion of SFAS 157 on the Company s consolidated financial position, statement of operations, and cash flows.

The Company adopted SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities-including an amendment of FASB Statement No. 115*, or SFAS 159, on January 1, 2008. This statement provides entities with an option to measure and report selected financial assets and liabilities at fair value. The Company does not intend to apply this standard to any of its eligible assets or liabilities; therefore, there was no impact on NRG s consolidated financial position, results of operations, or cash flows.

The Company adopted FSP FIN 39-1, *Amendment of FASB Interpretation No. 39*, or FSP FIN 39-1, which amends FIN 39, *Offsetting of Amounts Related to Certain Contracts*, on January 1, 2008. FSP FIN 39-1 impacts entities that enter into master netting arrangements as part of their derivative transactions. Under the guidance in this FSP, entities may choose to offset derivative positions in the financial statements against the fair value of amounts recognized as cash collateral paid or received under those arrangements. The Company chose not to offset positions as defined in this FSP; therefore there was no impact on NRG s consolidated financial position, results of operations, or cash flows.

NRG has non-qualified stock options for which it has insufficient historical exercise data and therefore estimates the expected term using the simplified method, as allowed under Staff Accounting Bulletin, or SAB, No. 107, *Share Based Payment*, or SAB 107. In December 2007, the SEC issued SAB No. 110, *Certain Assumptions Used in Valuation Methods*, which eliminates the December 31, 2007 expiration of SAB 107 s permission to use this simplified method. NRG will therefore continue to use this simplified method, for as long as the Company deems it to be the most appropriate method.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations*, or SFAS 141R. This statement applies prospectively to all business combinations for which the acquisition date is on or after the beginning of an entity s first annual reporting period beginning on or after December 15, 2008. The statement requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value at the acquisition date. It also recognizes and measures the goodwill acquired or a gain from a bargain purchase in the business combination and determines what information to disclose to enable users of an entity s financial statements to evaluate the nature and financial effects of the business combination. As discussed further in Note 12, *Income Taxes*, SFAS 141R will change the application of fresh start accounting to certain of the Company s unrecognized tax benefits. NRG is currently evaluating the impact of this statement upon its adoption on the Company s results of operations, financial position and cash flows.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51, Consolidated Financial Statements*, or SFAS 160. This Statement amends ARB No. 51 to establish accounting and reporting standards for the minority interest in a subsidiary and for the deconsolidation of a subsidiary. It also amends certain of ARB No. 51 s consolidation procedures for consistency with the requirements of SFAS 141R. This Statement shall be effective and applied prospectively for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008, except for the presentation and disclosure requirements, which shall be applied retrospectively. NRG is currently evaluating the impact of this statement upon its adoption on the Company s results of operations, financial position and cash flows.

In March 2008, the FASB issued SFAS No. 161, *Disclosures About Derivative Instruments and Hedging Activities*, or SFAS 161. SFAS 161 requires entities to provide enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended or* SFAS 133, and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. This statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. The enhanced disclosures regarding derivative and hedging instruments required by SFAS 161 are relevant to NRG, but will not have an impact on the Company s results of operations, financial position, or cash flows.

In April 2008, the FASB issued FSP No. FAS 142-3, *Determination of the Useful Life of Intangible Assets*, or FSP FAS 142-3. FSP FAS 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, *Goodwill and Other Intangible Assets.* FSP FAS 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years, with early adoption prohibited. NRG is currently evaluating the impact of this statement upon its adoption on the Company s results of operations, financial position and cash flows.

In May 2008, the FASB issued FSP No. APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)*, or FSP APB 14-1. FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement) do not fall within the scope of paragraph 12 of Accounting Principles Board Opinion No. 14, *Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants*, and specifies that issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the entity s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. FSP APB 14-1 does not apply to embedded conversion options that must be separately accounted for as derivatives under SFAS 133. FSP APB 14-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years and is to be applied retrospectively. NRG is currently evaluating the impact of this statement upon its adoption on the Company s results of operations, financial position and cash flows.

In June 2008, the Emerging Issues Task Force, or EITF, issued EITF No. 07-5, *Determining Whether an Instrument (or Embedded Feature) Is Indexed to an Entity s Own Stock*, or EITF 07-5. EITF 07-5 clarifies that contingent and other adjustment features in equity-linked financial instruments are consistent with equity indexation if they are based on variables that would be inputs to a plain vanilla option or forward pricing model and they do not increase the contract s exposure to those variables. EITF 07-5 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. NRG is currently evaluating the impact of this statement upon its adoption on the Company s results of operations, financial position and cash flows.

In September 2008, the FASB issued FSP FAS 133-1 and FIN 45-4, *Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161*, or FSP FAS 133-1 and FIN 45-4. This FSP amends FAS 133, and FIN 45 *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* to require additional disclosures about credit derivatives, credit derivatives embedded in a hybrid instrument, and the current status of the payment/performance risk of a guarantee. FSP FAS 133-1 and FIN 45-4 is effective for the financial statements of reporting periods (annual or interim) ending after November 15, 2008. NRG currently has no credit derivative contracts so there will be no impact on NRG related to credit derivatives. The clarification to SFAS 161 is not applicable to NRG as it only affects non-calendar year filers. The enhanced disclosures regarding the current status of the payment/performance risk of guarantees are relevant to NRG, but will not have an impact on the Company s results of operations, financial position, or cash flows.

In September 2008, the EITF issued EITF 08-5, *Issuer s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement*, or EITF 08-5. EITF 08-5 requires issuers of liability instruments with third-party credit enhancements to exclude the effect of the credit enhancement when measuring the liability s fair value. The effect of initially applying the requirements is included in the change in the instrument s fair value in the period of adoption. Entities are required to disclose the valuation technique used to measure the liabilities and to discuss any changes in the valuation techniques used to measure those liabilities in earlier periods. Entities will also need to disclose the existence of a third-party credit enhancement on the entity s issued debt. EITF 08-5 is effective on a prospective basis in the first reporting period beginning on or after December 15, 2008, with earlier application permitted. The fair value measurement requirements and enhanced disclosures regarding existence of third-party credit enhancements on the entity s issued debt and valuation techniques will not have an impact on the Company s results of operations, financial position, or cash flows.

On October 10, 2008, the FASB issued FSP No. FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active*, or FSP 157-3. This FSP clarifies the application of SFAS 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. FSP 157-3 is effective upon issuance, including prior periods for which financial statements have not been issued. Revisions resulting from a change in the valuation technique or its application shall be accounted for as a change in accounting estimate SFAS No. 154, *Accounting Changes and Error Corrections*, or SFAS 154. The disclosure provisions of SFAS 154 for a change in accounting estimate are not required for revisions resulting from a change in valuation technique or its application. Although effective for the period ended September 30, 2008, FSP 157-3 did not have an impact on the Company s results of operations, financial position, or cash flows.

Note 2 Comprehensive Income/(Loss)

The following table summarizes the components of the Company s comprehensive income, net of tax.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2008**	**2007**	**2008**	**2007**
Net income	$ 784	$ 268	$ 965	$ 482
Changes in derivative activity	1,112	46	112	(278)
Foreign currency translation adjustment	(104)	39	(54)	65
Unrealized gain/(loss) on available-for-sale securities	(4)		(1)	1
Other comprehensive income/(loss), net of tax	$ 1,004	$ 85	$ 57	$ (212)
Comprehensive income	$ 1,788	$ 353	$ 1,022	$ 270

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

(In millions) **As of September 30,**	**2008**
Accumulated other comprehensive loss as of December 31, 2007	$ (115)
Changes in derivative activity	112
Foreign currency translation adjustments	(54)
Unrealized loss on available-for-sale securities	(1)

Accumulated other comprehensive loss as of September 30, 2008	$	(58)

Table of Contents

Note 3 Discontinued Operations

NRG has classified material business operations and gains/losses recognized on sale as discontinued operations for projects that were sold or have met the required criteria for such classification. The financial results for the affected businesses have been accounted for as discontinued operations.

The assets and liabilities reported in the balance sheet as of December 31, 2007 as discontinued operations represent those of Itiquira Energetica S.A., or ITISA. On April 28, 2008, NRG completed the sale of its 100% interest in Tosli Acquisition B.V., or Tosli, which held all NRG s interest in ITISA, to Brookfield Renewable Power Inc. (previously Brookfield Power Inc.), a wholly-owned subsidiary of Brookfield Asset Management Inc. In addition, the purchase price adjustment contingency under the sale agreement was resolved on August 7, 2008. In connection with the sale, NRG received $300 million of cash proceeds from Brookfield, and removed $163 million of assets, including $59 million of cash, $122 million of liabilities, including $63 million of debt, and $15 million in foreign currency translation adjustment from its 2008 condensed consolidated balance sheet.

Summarized operating results for the Company s discontinued operations, consisting of ITISA s activities, were as follows:

	Three months ended September 30,		Nine months ended September 30,	
(In millions)	**2008**	**2007**	**2008**	**2007**
Operating revenues	$	$ 13	$ 20	$ 36
Operating costs and other expenses		7	9	18
Pre-tax income from operations of discontinued components		6	11	18
Income tax expense		3	3	5
Income from operations of discontinued components		3	8	13
Disposal of discontinued components pre-tax gain	3		273	
Income tax expense	3		109	
Gain on disposal of discontinued components, net of income tax			164	
Income from discontinued operations, net of income tax expense	$	$ 3	$ 172	$ 13

Note 4 Fair Value of Financial Instruments

Fair Value of Long-Term Debt

The Company s long-term debt is recorded at carrying value on the Company s consolidated balance sheet. The carrying amounts and fair value of the Company s long-term debt as of September 30, 2008 and December 31, 2007 were as follows:

	September 30, 2008		December 31, 2007	
(In millions)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt, including current portion	$ 8,028	$ 7,218	$ 8,180	$ 8,164

The fair value of long-term debt is based on quoted market prices for these instruments that are publicly traded, or estimated based on the income approach valuation technique for non-publicly traded debt using current interest rates for similar instruments with equivalent credit quality.

Table of Contents

Adoption of SFAS No. 157

The Company partially adopted SFAS 157 on January 1, 2008, delaying application for non-financial assets and non-financial liabilities as permitted. This statement establishes a framework for measuring fair value, and expands disclosures about fair value measurements.

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

Level 1 quoted prices (unadjusted) in active markets for identical assets or liabilities that the Company has the ability to access as of the measurement date. NRG s financial assets and liabilities utilizing Level 1 inputs include active exchange-traded securities, energy derivatives, and trust fund investments.

Level 2 inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. NRG s financial assets and liabilities utilizing Level 2 inputs include fixed income securities, exchange-based derivatives, and over-the-counter derivatives such as swaps, options and forwards.

Level 3 unobservable inputs for the asset or liability only used when there is little, if any, market activity for the asset or liability at the measurement date. NRG s financial assets and liabilities utilizing Level 3 inputs include infrequently-traded, non-exchange-based derivatives and commingled investment funds, and are measured using present value pricing models.

In accordance with SFAS 157, the Company determines the level in the fair value hierarchy within which each fair value measurement in its entirety falls, based on the lowest level input that is significant to the fair value measurement in its entirety.

Recurring Fair Value Measurements

The following table presents assets and liabilities measured and recorded at fair value on the Company s consolidated balance sheet on a recurring basis and their level within the fair value hierarchy as of September 30, 2008:

(In millions)	**Fair Value**			
As of September 30, 2008	**Level 1**	**Level 2**	**Level 3**	**Total**
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	$	$	$ 10	$ 10
Marketable equity securities	5			5
Trust fund investments	180	135	20	335
Derivative assets	2,152	2,832	22	5,006
Total assets	$ 2,337	$ 2,967	$ 52	$ 5,356
Derivative liabilities	$ 2,153	$ 3,023	$ 4	$ 5,180

The following table reconciles, for the period ended September 30, 2008, the beginning and ending balances for financial instruments that are recognized at fair value in the consolidated financial statements at least annually using significant unobservable inputs:

(In millions)	**Fair Value Measurement Using Significant Unobservable Inputs (Level 3)**			
Nine Months Ended September 30, 2008	**Debt Securities**	**Trust Fund Investments**	**Derivatives**	**Total**
Beginning balance as of January 1, 2008	$ 32	$ 37	$ 27	$ 96
Total gains and losses (realized/unrealized)				
Included in earnings	(22)		(19)	(41)
Included in nuclear decommissioning obligations		(9)		(9)
Included in other comprehensive income			28	28
Purchases/(sales), net		(9)	(17)	(26)
Transfer into Level 3		1	(1)	
Ending balance as of September 30, 2008	$ 10	$ 20	$ 18	$ 48
The amount of the total gains or losses for the period included in earnings attributable to the change in unrealized gains and losses relating to assets still held as of September 30, 2008	$ 22	$	$ 19	$ 41

Table of Contents

Realized and unrealized gains and losses included in earnings that are related to the debt securities are recorded in other income, while those related to energy derivatives are recorded in operating revenues.

Non-derivative fair value measurements

NRG s debt securities are classified as Level 3 and consist of non-traded debt instruments that are valued based on an auction process.

The trust fund investments are held primarily to satisfy NRG s nuclear decommissioning obligations. These trust fund investments hold debt and equity securities directly and equity securities indirectly through commingled funds. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. In addition, US Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding US Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized in Level 2. Commingled funds, which are analogous to mutual funds, are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair value of commingled funds are based on net asset values per fund share (the unit of account), derived from the quoted prices in active markets of the underlying equity securities. However, because the shares in the commingled funds are not publicly quoted, not traded in an active market and are subject to certain restrictions regarding their purchase and sale, the commingled funds are categorized in Level 3. See Note 5 *Nuclear Decommissioning Trust Fund.*

Derivative fair value measurements

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, on-line exchanges. For the majority of our markets we receive quotes from multiple sources. To the extent that we receive multiple quotes our 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 we only receive 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. The remainder of the assets and liabilities represent 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 11% 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, we apply a credit reserve to reflect credit risk which is calculated based on published default probabilities. To the extent that our net exposure under a specific master agreement is an asset we are using the counterparty s risk of default. If the exposure under a specific master agreement is a liability we are using NRG s probability of default. 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 September 30, 2008 the credit reserve resulted in a \$6 million decrease in fair value which is composed of a \$5 million gain in OCI and an \$11 million loss in derivative revenue. The fair values in each category reflect the level of forward prices and volatility factors as of September 30, 2008 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.

Under the guidance of FSP FIN 39-1, entities may choose to offset derivative positions in the financial statements against the fair value of the amounts recognized as cash collateral paid or received under those arrangements. The Company has credit arrangements within various agreements to call on or pay additional collateral support. The Company has chosen not to offset positions as defined in this FSP. As of September 30, 2008, the Company recorded $544 million of cash collateral paid and $154 million of cash collateral received on its balance sheet.

Table of Contents

Note 5 Nuclear Decommissioning Trust Fund

NRG s nuclear decommissioning trust fund assets which are for the decommissioning of South Texas Project, or STP, are primarily comprised of securities recorded at fair value based on actively quoted market prices. NRG accounts for these trust fund assets per SFAS 71, *Accounting for the Effects of Certain Types of Regulation*, because the Company s nuclear decommissioning activities are regulated by the Public Utility Commission of Texas, or PUCT. Although the owners of STP are responsible for the management of decommissioning STP, the cost of decommissioning is the responsibility of the Texas ratepayers. As such, NRG does not bear the cost for these decommissioning responsibilities, except to the extent that NRG has a prudence obligation with respect to the management of the trust funds and the future decommissioning of STP. Third party appraisals are periodically conducted to estimate the future decommissioning liability related to STP. These appraisals are then used to determine the adequacy of the existing decommissioning trust investments to cover that estimated future liability. Should there be a shortfall in the value of the assets in the trust relative to the estimated liability, NRG has the ability to file a rate case with the PUCT to increase decommissioning reimbursements over time from retail customers.

The following table summarizes the fair values of the securities held in the trust funds as of September 30, 2008 and December 31, 2007:

(In millions)	**September 30, 2008**	**December 31, 2007**
Cash and cash equivalents	$ 1	$ 4
US government and federal agency obligations	26	21
Federal agency mortgage-backed securities	65	59
Commercial mortgage-backed securities	23	22
Corporate debt securities	39	44
Marketable equity securities	179	234
Total	$ 333	$ 384

Note 6 Accounting for Derivative Instruments and Hedging Activities

SFAS 133, 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 Normal Purchase Normal Sale, or 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 Other Comprehensive Income, or OCI, until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge is immediately recognized in earnings.

Accumulated Other Comprehensive Income

The following tables summarize the effects of SFAS 133 on NRG s OCI balance attributable to hedged derivatives, net of tax:

(In millions) **Three months ended September 30, 2008**	**Energy Commodities**	**Interest Rate**	**Total**
Accumulated OCI balance at June 30, 2008	$ (1,235)	$ (30)	$ (1,265)
Realized from OCI during the period:			
Due to realization of previously deferred amounts	26		26
Mark-to-market of hedge contracts	1,088	(2)	1,086
Accumulated OCI balance at September 30, 2008	$ (121)	$ (32)	$ (153)
Gains expected to be realized from OCI during the next 12 months, net of $53 tax	$ 81	$	$ 81

(In millions) Three months ended September 30, 2007	Energy Commodities	Interest Rate	Total
Accumulated OCI balance at June 30, 2007	$ (145)	$ 30	$ (115)
Realized from OCI during the period:			
Due to realization of previously deferred amounts	(10)	(1)	(11)
Mark-to-market of hedge contracts	86	(29)	57
Accumulated OCI balance at September 30, 2007	$ (69)	$	$ (69)

(In millions) Nine months ended September 30, 2008	Energy Commodities	Interest Rate	Total
Accumulated OCI balance at December 31, 2007	$ (234)	$ (31)	$ (265)
Realized from OCI during the period:			
Due to realization of previously deferred amounts	32		32
Mark-to-market of hedge contracts	81	(1)	80
Accumulated OCI balance at September 30, 2008	$ (121)	$ (32)	$ (153)

(In millions) Nine months ended September 30, 2007	Energy Commodities	Interest Rate	Total
Accumulated OCI balance at December 31, 2006	$ 193	$ 16	$ 209
Realized from OCI during the period:			
Due to realization of previously deferred amounts	(37)	(1)	(38)
Mark-to-market of hedge contracts	(225)	(15)	(240)
Accumulated OCI balance at September 30, 2007	$ (69)	$	$ (69)

As of September 30, 2008 and 2007, the net balances in OCI relating to SFAS 133 were unrecognized losses of approximately $153 million and $69 million, which were net of income taxes of $102 million and $46 million, respectively.

As of July 31, 2008, our regression analysis for natural gas prices to ERCOT power prices did not meet the required threshold for cash flow hedge accounting for calendar years 2012 and 2013. As a result, we de-designated our 2012 and 2013 ERCOT cash flow hedges as of July 31, 2008. We will continue to monitor the correlations in this market, and if the regression analysis meets the required thresholds in the future, we may elect to re-designate these transactions as cash flow hedges.

Statement of Operations

In accordance with SFAS 133, unrealized gains and losses associated with changes in the fair value of derivative instruments not accounted for as 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.

	Three months ended September 30,		Nine months ended September 30,	
(In millions)	**2008**	**2007**	**2008**	**2007**
Unrealized mark-to-market results				
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	$ (7)	$ (17)	$ (32)	$ (109)
Reversal of previously recognized unrealized gains on settled positions related to trading activity	(9)	(3)	(20)	(23)
Net unrealized gains on open positions related to economic hedges	439	1	180	22
(Loss)/gain on ineffectiveness associated with open positions treated as cash flow hedges	352	9	(27)	32
Net unrealized gains on open positions related to trading activity	26	16	57	37
Total unrealized mark-to-market results	$ 801	$ 6	$ 158	$ (41)

Discontinued Hedge Accounting During the third quarter of 2008, a relatively mild summer season in the Northeast resulted in falling power prices and expected lower power generation for the remainder of 2008 and calendar year 2009. As such, NRG discontinued cash flow hedge accounting for certain contracts related to commodity price risk previously accounted for as cash flow hedges for 2008 and 2009. These contracts were originally entered into as hedges of forecasted sales by baseload plants. As a result, $31 million of gain previously deferred in OCI was recognized in earnings for the three and nine months ended September 30, 2008.

Note 7 Long-Term Debt

Debt Related to NRG Common Stock Finance I, LLC

In March 2008, the Company executed an arrangement with Credit Suisse, or CS, to extend the notes and preferred interest maturities of NRG Common Stock Finance I, LLC, or CSF I, from October 2008 to June 2010. In addition, the settlement date of an embedded derivative, or CSFI CAGR, which is based on NRG s share price appreciation beyond a 20% compound annual growth rate since the original date of purchase by CSF I, was extended 30 days to early December 2008. As part of this extension arrangement, the Company contributed 795,503 treasury shares to CSF I as additional collateral to maintain a blended interest rate in the CSF I facility of approximately 7.5%. Accordingly, the amount due at maturity in June 2010 for the CSF I notes and preferred interests will be $248 million.

In August 2008, the Company amended the CSF I notes and preferred interests to early settle the CSFI CAGR. Accordingly, NRG made a cash payment of $45 million to CS for the benefit of CSFI, which was recorded to interest expense in the Company s Consolidated Statement of Operations.

Senior Credit Facility

Beginning in 2008, NRG must annually offer a portion of its excess cash flow (as defined in the Senior Credit Facility) for the prior year to its first lien lenders under the Company s Term B loan. The percentage of the 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. The mandatory annual offer required for 2008 was $446 million, against which the Company made a prepayment of $300 million in December 2007. Of the remaining $146 million, the lenders accepted a repayment of $143 million in March 2008. The amount retained by the Company can be used for investments, capital expenditures and other items as permitted by the Senior Credit Facility.

Note 8 Changes in Capital Structure

The following table reflects the changes in NRG s common stock issued and outstanding during the nine months ended September 30, 2008:

	Authorized	Issued	Treasury	Outstanding
Balance as of December 31, 2007	500,000,000	261,285,529	(24,550,600)	236,734,929
2008 Capital Allocation Program			(4,691,883)	(4,691,883)
Shares issued from LTIP		984,176		984,176
Balance as of September 30, 2008	500,000,000	262,269,705	(29,242,483)	233,027,222

Treasury Stock

In December 2007, the Company initiated its 2008 Capital Allocation Program, with the repurchase of 2,037,700 shares of NRG common stock during that month for approximately $85 million. In February 2008, the

Company s Board of Directors authorized an additional $200 million in common share repurchases that would raise the total 2008 Capital Allocation Program to approximately $300 million. In the first quarter 2008, the Company repurchased 1,281,600 shares of NRG common stock for approximately $55 million. In the third quarter 2008, the Company repurchased an additional 3,410,283 of NRG common stock in the open market for approximately $130 million. As of September 30, 2008, NRG had repurchased a total of 6,729,583 shares of NRG common stock at a cost of approximately $270 million as part of its 2008 Capital Allocation Program.

Note 9 Equity Compensation

Non-Qualified Stock Options, or NQSO s

The following table summarizes the Company s NQSO activity as of September 30, 2008 and the changes during the nine months then ended:

	Shares	Weighted Average Exercise Price	Aggregate Intrinsic Value (In millions)
Outstanding as of December 31, 2007	3,579,775	$ 19.98	
Granted	1,174,200	40.48	
Forfeited	(148,536)	32.79	
Exercised	(507,986)	16.29	
Outstanding at September 30, 2008	4,097,453	25.84	$
Exercisable at September 30, 2008	2,056,803	$ 17.54	15

The weighted average grant date fair value of NQSO s granted for the nine months ending September 30, 2008 was $10.61.

Restricted Stock Units, or RSU s

The following table summarizes the Company s non-vested RSU awards as of September 30, 2008 and changes during the nine months then ended:

	Units	Weighted Average Grant-Date Fair Value Per Unit
Non-vested as of December 31, 2007	1,588,316	$ 26.99
Granted	163,200	40.22
Vested	(610,760)	19.38
Forfeited	(71,320)	31.13
Non-vested as of September 30, 2008	1,069,436	$ 33.08

Performance Units, or PU s

The following table summarizes the Company s non-vested PU awards as of September 30, 2008 and changes during the nine months then ended:

	Units	Weighted Average Grant- Date Fair Value Per Unit
Non-vested as of December 31, 2007	536,764	$ 20.18
Granted	227,300	27.75
Vested	(50,000)	15.74
Forfeited	(59,700)	21.49
Non-vested as of September 30, 2008	654,364	$ 23.05

In the third quarter 2008, 100,000 shares of common stock were issued for performance units that vested in accordance with the plan payout provisions.

Employee Stock Purchase Plan

In May 2008, NRG shareholders approved the adoption of the NRG Energy, Inc. Employee Stock Purchase Plan, or ESPP, pursuant to which eligible employees may elect to withhold up to 10% of their eligible compensation to purchase shares of NRG common stock at 85% of its fair market value on the exercise date. An exercise date occurs each June 30 and December 31. The initial six month employee withholding period began July 1, 2008 and ends December 31, 2008. There are 500,000 shares of treasury stock reserved for issuance under the ESPP.

Table of Contents

Note 10 Earnings Per Share

Basic earnings per common share is computed by dividing net income 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 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.

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

(In millions, except per share data)	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Basic earnings per share				
Numerator:				
Income from continuing operations	$ 784	$ 265	$ 793	$ 469
Preferred stock dividends	(13)	(13)	(41)	(41)
Net income available to common stockholders from continuing operations	771	252	752	428
Discontinued operations, net of income tax expense		3	172	13
Net income available to common stockholders	$ 771	$ 255	$ 924	$ 441
Denominator:				
Weighted average number of common shares outstanding	234.8	239.4	235.7	240.5
Basic earnings per share:				
Income from continuing operations	$ 3.28	$ 1.05	$ 3.19	$ 1.78
Discontinued operations, net of income tax expense		0.02	0.73	0.05
Net income	$ 3.28	$ 1.07	$ 3.92	$ 1.83
Diluted earnings per share				
Numerator:				
Net income available to common stockholders from continuing operations	$ 771	$ 252	$ 752	$ 428
Add preferred stock dividends for dilutive preferred stock	11	11	34	34

Adjusted income from continuing operations available to common shareholders	782	263	786	462
Discontinued operations, net of tax		3	172	13
Net income available to common stockholders	$ 782	$ 266	$ 958	$ 475
Denominator:				
Weighted average number of common shares outstanding	234.8	239.4	235.7	240.5
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	2.2	3.8	3.0	3.7
Incremental shares attributable to embedded derivatives of certain financial instruments (if-converted method)	2.0	4.6	1.8	4.9
Incremental shares attributable to assumed conversion features of outstanding preferred stock (if-converted method)	37.5	37.5	37.5	37.5
Total dilutive shares	276.5	285.3	278.0	286.6
Diluted earnings per share:				
Income from continuing operations available to common shareholders	$ 2.83	$ 0.92	$ 2.83	$ 1.61
Income from discontinued operations, net of tax		0.01	0.62	0.05
Net income	$ 2.83	$ 0.93	$ 3.45	$ 1.66

Effects on Earnings per Share

The following table summarizes NRG s outstanding equity instruments that are anti-dilutive and were not included in the computation of the Company s diluted earnings per share:

(In millions of shares)	Three Months Ended September 30, 2008	2007	Nine Months Ended September 30, 2008	2007
Equity compensation	1.8		1.4	0.4
Embedded derivative of 3.625% convertible perpetual preferred stock	14.0	13.2	14.2	13.0
Embedded derivative of preferred interests and notes issued by CSF I and CSF II	8.3	16.7	8.3	16.6
Total	24.1	29.9	23.9	30.0

Note 11 Segment Reporting

The Company s segment structure reflects NRG s 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.

)	Wholesale Power Generation								
hs Ended September 30, 2008	Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	
venues	$ 1,661	$ 677	$ 233	$ 40	$ 41	$ 36	$ 3	$ (1)	$
and amortization	108	26	16	2		3	1		
nings of unconsolidated affiliates	40			1	17				
) from continuing operations e taxes	1,050	351	24	13	25	4	(152)	(1)	
discontinued operations, net of									
loss)	$ 594	$ 351	$ 24	$ 13	$ 19	$ 4	$ (220)	$ (1)	$
	$ 12,102	$ 1,634	$ 942	$ 53	$ 1,002	$ 212	$ 19,006	$ (11,268)	$

millions) ree Months Ended September 30, 2007	Wholesale Power Generation Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
rating revenues	$ 956	$ 502	$ 200	$ 33	$ 38	$ 36	$ 7	$	$ 1,772
reciation and amortization	113	25	17	1		3	1		160
ity in earnings of unconsolidated affiliates				1	18				19
ome/(loss) from continuing operations ore income taxes	275	171	18	13	25	4	(96)		410
ome from discontinued operations, net of ome taxes					3				3
income/(loss)	$ 161	$ 171	$ 17	$ 13	$ 54	$ 4	$ (152)	$	$ 268

Table of Contents

nillions) Months Ended September 30, 2008	Texas	Northeast	Wholesale Power Generation South Central	West	International	Thermal	Corporate	Elimination	Total
ating revenues	$ 3,061	$ 1,302	$ 584	$ 127	$ 122	$ 114	$ 1	$ (3)	$ 5,30
eciation and amortization	334	77	50	6		8	3		47
y in (losses)/earnings of unconsolidated ates	(10)			(2)	47				3
ne/(loss) from continuing operations e income taxes	1,131	365	57	38	72	11	(339)	(11)	1,32
ne from discontinued operations, net of ne taxes					172				17
ncome/(loss)	$ 644	$ 365	$ 57	$ 38	$ 229	$ 11	$ (368)	$ (11)	$ 96

nillions) e Months Ended September 30, 2007	Texas	Northeast	Wholesale Power Generation South Central	West	International	Thermal	Corporate	Elimination	Total
ating revenues	$ 2,526	$ 1,239	$ 514	$ 90	$ 102	$ 122	$ 29	$ (15)	$ 4,607
eciation and amortization	341	74	51	2		9	4		481
y in (losses)/earnings of unconsolidated ates				(2)	42				40
me/(loss) from continuing operations e income taxes	624	319	24	26	60	32	(304)	(12)	769
me from discontinued operations, net of ne taxes					13				13
ncome/(loss)	$ 355	$ 319	$ 23	$ 26	$ 88	$ 32	$ (349)	$ (12)	$ 482

Note 12 Income Taxes

Income tax expense from continuing operations for the three months and nine months ended September 30, 2008 was $530 million and $531 million, respectively, compared to $145 million and $300 million for the three and nine months ended September 30, 2007, respectively. The income tax expense for the three months and nine months ended September 30, 2008 included domestic tax expense of $523 million and $515 million, respectively, and foreign tax expense of $7 million and $16 million, respectively. The income tax expense for the three and nine months ended September 30, 2007 included domestic tax expense of $171 million and $314 million, respectively, and a foreign tax benefit of $26 million and $14 million, respectively.

A reconciliation of the US statutory rate to NRG s effective tax rate from continuing operations is as follows:

(In millions except percentages) **Nine Months Ended September 30,**	**2008**	**2007**
Income from continuing operations before income taxes	$ 1,324	$ 769
Tax at 35%	463	269
State taxes	62	37
Valuation allowance	(1)	1
Foreign operations	(10)	(5)
Foreign dividend	5	21
Non-deductible interest	24	7
Change in German tax rate		(30)
Section 199 Manufacturing Deduction	(17)	(3)
Other permanent differences including subpart F income	5	3
Income tax expense	$ 531	$ 300
Effective income tax rate	40.1%	39.0%

The effective income tax rate for the nine months ended September 30, 2008 and 2007 differs from the US statutory rate of 35% due to a taxable dividend from foreign operations and non-deductible interest, offset by earnings in foreign jurisdictions that are taxed at rates lower than the US statutory rate.

Table of Contents

Tax Payable

As of September 30, 2008, NRG recorded a current tax payable of $191 million for domestic federal and state taxes.

Deferred tax assets and valuation allowance

Net deferred tax balance As of September 30, 2008, NRG recorded a net deferred tax liability of $560 million. However, due to an assessment of positive and negative evidence, including projected capital gains and available tax planning strategies, NRG believes that it is more likely than not that a benefit will not be realized on $539 million of tax assets, thus a valuation allowance has remained, resulting in a net deferred tax liability of $1,099 million.

NOL carryforwards As of September 30, 2008, the Company had cumulative foreign NOL carryforwards of $253 million, of which $54 million will expire starting in 2011 through 2017 and $199 million do not have an expiration date.

Uncertain tax benefits

NRG has identified certain unrecognized tax benefits whose after-tax value was $709 million, of which $36 million would impact the Company s income tax expense. Of the $709 million in unrecognized tax benefits, $673 million relates to periods prior to the Company s emergence from bankruptcy. In accordance with Statement of Position 90-7, *Financial Reporting by Entities in Reorganization under the Bankruptcy Code*, and the application of fresh start accounting, recognition of previously unrecognized tax benefits existing pre-emergence would not impact the Company s effective tax rate but would increase additional paid-in capital, or APIC. In accordance with SFAS 141R, any changes to our uncertain tax benefits occurring after January 1, 2009 will be credited to income tax expense rather than APIC.

As of September 30, 2008, NRG has recorded a $138 million non-current tax liability for unrecognized tax benefits, resulting from taxable earnings for the period, for which there are no NOLs available to offset for financial statement purposes. NRG accrued interest and penalties related to these unrecognized tax benefits of approximately $4 million as of September 30, 2008. The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. For the nine months ended September 30, 2008, the Company incurred an immaterial amount of interest and penalties related to its unrecognized tax benefits.

Tax jurisdictions NRG is subject to examination by taxing authorities for income tax returns filed in the US federal jurisdiction and various state and foreign jurisdictions including major operations located in Germany and Australia. The Company is no longer subject to US federal income tax examinations for years prior to 2002. With few exceptions, state and local income tax examinations are no longer open for years before 2003. The Company s significant foreign operations are also no longer subject to examination by local jurisdictions for years prior to 2000.

The Company has been contacted for examination by the Internal Revenue Service for years 2004 through 2006. The audit commenced during the third quarter 2008 and is expected to continue for approximately 18 to 24 months.

Table of Contents

Note 13 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 Texas-based employees. The total amount of employer contributions paid for the nine months ended September 30, 2008 was $57 million. NRG expects to make $7 million in further contributions for the remainder of 2008.

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 September 30,		Nine Months Ended September 30,	
(In millions)	**2008**	**2007**	**2008**	**2007**
Service cost benefits earned	$ 4	$ 3	$ 11	$ 11
Interest cost on benefit obligation	4	4	13	13
Net gain			(1)	
Expected return on plan assets	(4)	(3)	(11)	(9)
Net periodic benefit cost	$ 4	$ 4	$ 12	$ 15

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

	Other Postretirement Benefits Plans			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2008**	**2007**	**2008**	**2007**
Service cost benefits earned	$ 1	$ 1	$ 2	$ 2
Interest cost on benefit obligation	1	2	4	4
Net periodic benefit cost	$ 2	$ 3	$ 6	$ 6

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 nine months ended September 30, 2008 was $4 million. The Company recognized net periodic costs related to its 44% interest in STP defined benefits plans of $2 million and $1 million for the three months ended September 30, 2008 and 2007, respectively. The Company recognized net periodic costs related to its 44% interest in STP defined benefits plan of $6 million and $5 million for the nine months ended September 30, 2008 and 2007, respectively.

Table of Contents

Note 14 Commitments and Contingencies

Commitments

Fuel Commitments

NRG enters into long-term contractual arrangements to procure fuel and transportation services for the Company s generation assets. NRG entered into additional coal purchase agreements during the nine months ended September 30, 2008 with total commitments of approximately $465 million, spanning from 2008 through 2011. In addition, NRG s natural gas purchase commitments have decreased by approximately $264 million during the nine months ended September 30, 2008 as the 2008 monthly commitments were settled.

First and Second Lien Structure

NRG has granted first and second liens to certain counterparties on substantially all of the Company s assets in the United States in order to secure primarily long-term obligations under power and gas sale agreements and related contracts. NRG uses the first or 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-the-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 is limited by volumes hedged, not by the value of underlying out-of-the money positions. The first lien program does not require us 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 rolling 60 months with such permitted hedging volumes 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.

As part of the amendments to NRG s Senior Credit Facility entered into on June 8, 2007, the Company obtained the ability to move its second lien counterparty exposure to the first lien on a *pari passu* basis with the Company s existing first lien lenders. In exchange for moving to a *pari passu* basis with the Company s first lien lenders, the counterparties relinquished letters of credit issued by NRG which they held as a part of their collateral package.

The Company s lien counterparties may have a claim on our assets to the extent their net positions are out-of-the-money. As of September 30, 2008 and October 23, 2008, the first lien exposure of net out-of-the-money positions to counterparties on hedges was $405 million and $185 million, respectively. As of September 30, 2008 and October 23, 2008, the second lien net out-of-the-money positions to counterparties on hedges were approximately $16 million and $2 million, respectively.

RepoweringNRG

NRG has made non-refundable payments relating to *Repowering*NRG projects totaling approximately $148 million primarily towards the procurement of wind turbines. The Company believes that these payments are necessary for the timely and successful execution of these projects. The payments are in support of expected deliveries of wind turbines and other equipment totaling approximately $248 million through 2009. In addition, as discussed further in Note 1, *Basis of Presentation*, NRG expects to contribute approximately $87 million in equity to Sherbino in 2008 and has posted a letter of credit in that amount. To date, NRG has made capital contributions to Sherbino in the amount of $17 million. Also, NRG s share of cash security posted to The Connecticut Light and Power Company by GenConn

Energy LLC, or GenConn, a 50/50 joint venture vehicle of NRG and The United Illuminating Company, for the project at Devon Station is approximately $9 million.

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. Pursuant to the requirements of SFAS No. 5, *Accounting for Contingencies*, or SFAS 5, and related guidance, 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. 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

On December 19, 2006, the US Court of Appeals for the Ninth Circuit reversed the Federal Energy Regulatory Commission s, or FERC s, prior determinations regarding the enforceability of certain wholesale power contracts and remanded the case to FERC for further proceedings consistent with the decision. One of these contracts was the wholesale power contract between the California Department of Water Resources, or CDWR, and subsidiaries of WCP. This case originated with a February 2002 complaint filed at FERC by the State of California alleging that many parties, including WCP subsidiaries, overcharged the State. For WCP, the alleged overcharges totaled approximately $940 million for 2001 and 2002. The complaint demanded that FERC abrogate the CDWR contract and sought refunds associated with revenues collected under the contract. In 2003, FERC rejected this complaint, denied rehearing, and the case was appealed to the Ninth Circuit where oral argument was held on December 8, 2004. On December 19, 2006, the Court decided that in FERC s review of the contracts at issue, FERC could not rely on the Mobil-Sierra standard presumption of just and reasonable rates, where such contracts were not reviewed by FERC with full knowledge of the then existing market conditions. On May 3, 2007, WCP and the other defendants filed separate petitions for certiorari seeking review by the US Supreme Court. On June 26, 2008, the Supreme Court issued its decision. The Court held (1) that the *Mobil-Sierra* public interest standard of review applied to contracts made under a seller s market-based rate authority; (2) that the public interest bar required to set aside a contract remains a very high one to overcome; and (3) that the *Mobil-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. The Supreme Court affirmed the Ninth Circuit s decision, agreeing that the case should be remanded to FERC to clarify 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. Although WCP s petition for review was not heard by the Supreme Court, the Supreme Court s decision with respect to the Morgan Stanley petition applies equally to WCP.

On October 20, 2008, the Ninth Circuit ordered the parties, including FERC, to submit short briefs on the question of whether that Court should answer a question that the US Supreme Court did not address in its June 26, 2008, decision.

That question is whether the *Mobil-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 the case. WCP s response is due November 14, 2008.

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 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.

Table of Contents

Station Service Disputes

On October 2, 2000, Niagara Mohawk Power Corporation, or NiMo, commenced an action against NRG in New York state court seeking damages related to NRG s alleged failure to pay retail tariff amounts for utility services at the Dunkirk plant between June 1999 and September 2000. The parties agreed to consolidate this action with two other actions against the Huntley and Oswego plants. On October 8, 2002, by stipulation and order, this action was stayed pending submission to FERC of the disputes in the action. At FERC, NiMo asserted the same claims and legal theories, and on November 19, 2004, FERC denied NiMo s petition and ruled that the NRG facilities could net their service obligations over each 30 calendar day period from the day NRG acquired the facilities. In addition, FERC ruled that neither NiMo nor the New York Public Service Commission could impose a retail delivery charge on the NRG facilities because they are interconnected to transmission and not to distribution. NiMo appealed to the US Court of Appeals for the D.C. Circuit which, on June 23, 2006, denied the appeal finding that New York Independent System Operator s, or NYISO s, station service program that permits generators to self supply their station power needs by netting consumption against production in a month is lawful. On April 30, 2007, the US Supreme Court denied NiMo s request for review of the D.C. Circuit decision thus ending further avenues to appeal FERC s ruling in this matter. NRG believes it is adequately reserved.

On December 14, 1999, NRG acquired certain generating facilities from CL&P. A dispute arose over station service power and delivery services provided to the facilities. On December 20, 2002, as a result of a petition filed at FERC by Northeast Utilities Services Company on behalf of itself and CL&P, FERC issued an order finding that, at times when NRG is not able to self-supply its station power needs, there is a sale of station power from a third-party and retail charges apply. In August 2003, the parties agreed to submit the dispute to binding arbitration. On September 11, 2007, the parties argued the dispute before a three judge arbitration panel. On February 19, 2008, the parties executed a settlement agreement ending the arbitration, and on April 30, 2008, that settlement agreement became effective thereby ending the case.

Native Village of Kivalina and City of Kivalina

Twenty-four electric generating companies and oil and gas companies were named as defendants in this complaint, in which damages of up to $400 million had been asserted. The complaint was filed on behalf of a small Alaskan town and sought damages associated with the need to relocate from the northern coast of Alaska purportedly because of the effects of global warming caused by the defendant s CO_2 emissions. On June 11, 2008, NRG and the plaintiffs executed a Stipulation of Dismissal with Prejudice and on June 16, 2008, the US District Court for the Northern District of California dismissed NRG with prejudice thereby ending the case for NRG. The Company had argued to the plaintiffs that their allegations were blocked by NRG s 2003 bankruptcy. NRG did not pay any money or exchange anything of value with the plaintiffs in exchange for its dismissal.

Spring Creek Coal Company

In August 2007, Spring Creek Coal Company filed a complaint against NRG Texas LP, NRG South Texas LP, NRG Texas Power LLC, NRG Texas LLC, and NRG Energy, Inc. in the US District Court for the federal district of Wyoming. The complaint alleged multiple breaches in 2007 of a 1978 coal supply agreement as amended by a later 1987 agreement, which plaintiff alleges is a take or pay contract. On April 10, 2008, the parties reached a settlement in principal ending the litigation and on May 5, 2008, the parties executed a settlement agreement. On May 15, 2008, the case was dismissed with prejudice thereby ending the matter. While neither party admitted liability in the settlement, NRG paid Spring Creek approximately $18 million for the amount of coal it did not take in 2007 and NRG s obligation to take coal under the coal supply agreement in the future was reduced by an identical amount. In addition, NRG is receiving a price reduction on all remaining tons under the coal supply agreement valued at approximately $3 million. NRG recorded expense of $15 million in connection with the settlement.

Disputed Claims Reserve

As part of NRG s plan of reorganization, NRG funded a disputed claims reserve for the satisfaction of certain general unsecured claims that were disputed claims as of the effective date of the plan. Under the terms of the plan, as such claims are resolved, the claimants are paid from the reserve on the same basis as if they had been paid out in the bankruptcy. To the extent the aggregate amount required to be paid on the disputed claims exceeds the amount remaining in the funded claims reserve, NRG will be obligated to provide additional cash and common stock to satisfy the claims. Any excess funds in the disputed claims reserve will be reallocated to the creditor pool for the pro rata benefit of all allowed claims. The contributed common stock and cash in the reserves is held by an escrow agent to complete the distribution and settlement process. Since NRG has surrendered control over the common stock and cash provided to the disputed claims reserve, NRG recognized the issuance of the common stock as of December 6, 2003 and removed the cash amounts from the balance sheet. Similarly, NRG removed the obligations relevant to the claims from the balance sheet when the common stock was issued and cash contributed.

On April 3, 2006, the Company made a supplemental distribution to creditors under the Company s Chapter 11 bankruptcy plan, totaling $25 million in cash and 5,082,000 shares of common stock. As of October 23, 2008, the reserve held approximately $10 million in cash and approximately 1,319,142 shares of common stock. NRG believes the cash and stock together represent sufficient funds to satisfy all remaining disputed claims. During the fourth quarter of 2008, NRG expects to file with the US Bankruptcy Court for the Southern District of New York, a Closing Report and an Application for Final Decree Closing the Chapter 11 Case for NRG Energy, Inc. et al.

Note 15 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 wholesale power markets are subject to ongoing legislative and regulatory changes.

New England On July 16, 2007, FERC conditionally accepted, subject to refund, the Reliability-Must-Run, or RMR, agreement filed on April 26, 2007 by Norwalk Power for its units 1 and 2, specifying a June 19, 2007 effective date. Norwalk s RMR rate and its eligibility for the RMR agreement, which is based upon the facility s projected market revenues and costs, are subject to further proceedings. Norwalk filed for the RMR agreement in response to FERC s order eliminating the Peaking Unit Safe Harbor bidding mechanism which took effect on June 19, 2007. Settlement proceedings are still ongoing.

On March 18, 2008, the US Court of Appeals for the D.C. Circuit rejected the appeal filed by the Attorneys General of the State of Connecticut and Commonwealth of Massachusetts regarding the settlement of the New England capacity market design. The settlement, filed with FERC on March 7, 2006, by a broad group of New England market participants, provides for interim capacity transition payments for all generators in New England for the period starting December 1, 2006 through May 31, 2010, and a Forward Capacity Market, or FCM, for the period thereafter. All substantive challenges to the settlement, to the validity of the interim capacity transition payments, and to the market design were rejected by the D.C. Circuit, although one procedural argument relating to future challenges by non-settling parties was sustained. Several parties sought rehearing on this issue due to concerns regarding the sanctity of contracts. On October 6, 2008, the D.C. Circuit denied all requests for rehearing.

New York On March 7, 2008, FERC issued an order accepting the NYISO s proposed market reforms to the in-city Installed Capacity, or ICAP, market, with only minor modifications. On October 4, 2007, the NYISO had filed its proposal for revising the ICAP market for the New York City zone. The proposal retains the existing ICAP market structure, but imposes additional market power mitigation on the current owners of Consolidated Edison s divested generation units in New York City (which include NRG s Arthur Kill and Astoria facilities), who are deemed to be pivotal suppliers. Specifically, the NYISO proposal imposes a new reference price on pivotal suppliers and requires bids to be submitted at or below the reference price. The new reference price is derived from the expected clearing price based upon the intersection of the supply curve and the ICAP Demand Curve if all suppliers bid as price-takers. The NYISO s proposed reforms became effective March 27, 2008. Although FERC had established a refund effective date of May 12, 2007, its March 7 order determined that the NYISO s proposal should be implemented only prospectively and that no refunds should be required. No party sought rehearing on the refund issue, thus resolving the contingency. On September 29, 2008, FERC issued its order on rehearing and the NYISO s compliance filings that substantially reaffirmed the NYISO s proposed market reforms.

On March 15, 2006, NRG received the results from NYISO Market Monitoring Unit s review of NRG S Astoria plant s 2004 Generating Availability Data System, or GADS, reporting. On July 25, 2008, the NYISO determined that it would assess NRG a capacity deficiency charge relating to the Astoria plant as a result of a restatement of its GADS data for 2004. NRG agreed to and paid the NYISO s assessment.

PJM On August 23, 2007, several entities, including the New Jersey Board of Public Utilities, the District of Columbia Office of the People s Counsel, and the Maryland Office of People s Counsel, filed appeals of the FERC orders accepting the settlement of the locational capacity market for PJM Interconnection, LLC. The settlement, filed at FERC on September 29, 2006, provides for a capacity market mechanism known as the Reliability Pricing Model, or RPM, which is designed to provide a long-term price signal through competitive forward auctions. On December 22, 2006, FERC issued an order accepting the settlement, which was reaffirmed on rehearing by order dated June 25, 2007. The RPM auctions have been conducted and capacity payments pursuant to the RPM mechanism have commenced. A successful appeal by the appellants could disturb the settlement and create a refund obligation of capacity payments.

On January 15, 2008, the Maryland Public Service Commission, or MDPSC, filed at FERC a complaint against PJM claiming that PJM had failed to adequately mitigate certain generation resources, due to exemptions for resources used to relieve reactive limits on interfaces or that were constructed during certain periods after 1999. In addition to seeking an order eliminating the exemptions and a refund effective date as of the date of the complaint, the MDPSC sought an investigation of periods prior to the complaint that could have led to disgorgement by certain entities, and possibly a resettlement of the market. On May 16, 2008, FERC issued an order granting in part, and dismissing in part, the complaint and establishing a proceeding to examine the justness and reasonableness of PJM s other market power mitigation mechanisms. FERC denied the request for retroactive relief and resettlement of the market.

On May 30, 2008, the MDPSC, together with other load interests, filed at FERC a complaint against PJM challenging the results of the RPM transition Base Residual Auctions for installed capacity, held between April 2007 and January 2008. The complaint seeks 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 September 19, 2008, FERC dismissed the complaint. The parties representing load interests have sought rehearing of the dismissal of the complaint. In a related proceeding, FERC directed PJM to commence stakeholder processes towards addressing issues with RPM and required PJM to make a filing of proposed changes to RPM no later than December 15, 2008.

Note 16 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 US. 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 gas, or GHG, including 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 to be incurred from 2008 through 2013 will be approximately $1.3 billion. These capital expenditures, in general, are related to installation of particulate, SO_2, NOx, 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 anticipated changes in schedules and controls related to recent court rulings that vacate both the Clean Air Interstate Rule, or CAIR, and the Clear Air Mercury Rule, or CAMR, the full impact on the scope and timing of environmental retrofits from any revised and/or replacement regulations cannot be determined at this time.

Northeast Region

On December 20, 2005, 10 northeastern states entered into a Memorandum of Understanding, or MOU, to create the Regional Greenhouse Gas Initiative, or RGGI, to establish a cap-and-trade GHG program for electric generators. Electric generating units in participating RGGI states will have to procure one allowance for every US ton of CO_2 emitted with true up for 2009-2011 occurring in 2012. NRG units located in Connecticut, Delaware, Maryland, Massachusetts and New York emitted approximately 13 million US tons of CO_2 in 2007. NRG believes that to the extent allowance costs will not be fully reflected in wholesale electricity prices, the direct financial impact on the Company is likely to be negative as costs are incurred to secure the necessary RGGI allowances and offsets at auction and in the market.

On May 29, 2008, the Delaware Department of Natural Resources, or DNREC, issued an invitation to NRG s Indian River Operations, Inc. to 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 the DNREC and other Trustees to close out the property.

South Central Region

On January 27, 2004, NRG s Louisiana Generating LLC and the Company s Big Cajun II plant received a request under Section 114 of the Clean Air Act, or CAA, from USEPA seeking information primarily related to physical changes made at the Big Cajun II plant, and subsequently received a notice of violation, or NOV, on February 15, 2005, alleging that NRG s predecessors had undertaken projects that triggered requirements under the Prevention of Significant Deterioration, or PSD, program, including the installation of emission controls. NRG submitted multiple responses commencing February 27, 2004 and ending on October 20, 2004. On May 9, 2006, these entities received from the Department of Justice, or DOJ, a notice of deficiency related to their responses, to which NRG responded on May 22, 2006. A document review was conducted at NRG s Louisiana Generating LLC offices by the DOJ during the week of August 14, 2006. On December 8, 2006, the USEPA issued a supplemental NOV updating the original February 15, 2005 NOV. Discussions with the USEPA are ongoing and the Company cannot predict with certainty the outcome of this matter.

Note 17 Guarantees

NRG and its subsidiaries enter into various contracts that include indemnification and guarantee provisions as a routine part of the Company s business activities. Examples of these contracts include asset purchases and sale agreements, commodity sale and purchase agreements, joint venture agreements, operation and maintenance agreements, service agreements, settlement agreements, and other types of contractual agreements with vendors and other third parties. These contracts generally indemnify the counterparty for tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements. In some cases, NRG s maximum potential liability cannot be estimated, since the underlying agreements contain no limits on potential liability.

This footnote should be read in conjunction with the complete description under Note 25, *Guarantees*, to the Company s financial statements in its Annual Report on Form 10-K for the year ended December 31, 2007.

For the nine months ended September 30, 2008, NRG had net increases to its guarantee obligations under other commercial arrangements of approximately $202 million.

Table of Contents

Note 18 Condensed Consolidating Financial Information

As of September 30, 2008, the Company had $1.2 billion of 7.25% Senior Notes due 2014, $2.4 billion of 7.375% Senior Notes due 2016 and $1.1 billion of 7.375% Senior Notes due 2017 outstanding. These notes are guaranteed by certain of NRG s current and future wholly-owned domestic subsidiaries, or guarantor subsidiaries.

Each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of September 30, 2008:

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
Chickahominy River Energy Corp.
Commonwealth Atlantic Power LLC
Conemaugh Power LLC
Connecticut Jet Power LLC
Devon Power LLC
Dunkirk Power LLC
Eastern Sierra Energy Company
El Segundo Power, LLC
El Segundo Power II LLC
GCP Funding Company LLC
Hanover Energy Company
Hoffman Summit Wind Project LLC
Huntley IGCC LLC
Huntley Power LLC
Indian River IGCC LLC
Indian River Operations Inc.
Indian River Power LLC
James River Power LLC
Kaufman Cogen LP
Keystone Power LLC
Lake Erie Properties Inc.
Louisiana Generating LLC
Middletown Power LLC
Montville IGCC LLC
Montville Power LLC
NEO Chester-Gen LLC
NEO Corporation
NEO Freehold-Gen LLC
NEO Power Services Inc.
New Genco GP LLC
Norwalk Power LLC
NRG Affiliate Services Inc.
NRG Construction LLC
NRG Devon Operations Inc.
NRG Dunkirk Operations, Inc.
NRG El Segundo Operations Inc.
NRG Generation Holdings, Inc.
NRG Huntley Operations Inc.
NRG International LLC
NRG Kaufman LLC
NRG Mesquite 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 Rocky Road 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 Power LLC
NRG West Coast LLC
NRG Western Affiliate Services Inc.
Oswego Harbor Power LLC
Padoma Wind Power, LLC
Saguaro Power LLC
San Juan Mesa Wind Project II, LLC
Somerset Operations Inc.
Somerset Power LLC
Texas Genco Financing Corp.
Texas Genco GP, LLC

NRG Arthur Kill Operations Inc.
NRG Asia-Pacific Ltd.
NRG Astoria Gas Turbine Operations Inc.
NRG Bayou Cove LLC
NRG Cabrillo Power Operations Inc.
NRG Cadillac Operations Inc.
NRG California Peaker Operations LLC
NRG Cedar Bayou Development Company LLC
NRG Connecticut Affiliate Services Inc.
Texas Genco Holdings, Inc.
Texas Genco LP, LLC
Texas Genco Operating Services, LLC
Texas Genco Services, LP
Vienna Operations, Inc.
Vienna Power LLC
WCP (Generation) Holdings LLC
West Coast Power LLC

Table of Contents

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 Energy, Inc., the guarantor subsidiaries and the non-guarantor subsidiaries in accordance with Rule 3-10 under the SEC 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.

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Three Months Ended September 30, 2008

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (a)	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 2,597	$ 111	$	$ (18)	$ 2,690
Operating Costs and Expenses					
Cost of operations	919	99	(3)	(18)	997
Depreciation and amortization	148	7	1		156
General and administrative	16	14	45		75
Development costs	2	2	9		13
Total operating costs and expenses	1,085	122	52	(18)	1,241
Operating Income/(Loss)	1,512	(11)	(52)		1,449
Other Income/(Expense)					
Equity in earnings/(losses) of consolidated subsidiaries	52		897	(949)	
Equity in earnings of unconsolidated affiliates	1	57			58
Other income/(expense), net	4	11	(22)		(7)
Interest expense	(46)	(61)	(79)		(186)
Total other income/(expense)	11	7	796	(949)	(135)
Income/(Losses) From Continuing Operations Before Income Taxes	1,523	(4)	744	(949)	1,314
Income tax expense/(benefit)	532	38	(40)		530
Income/(Losses) From Continuing Operations	991	(42)	784	(949)	784
Income/(Losses) from discontinued operations, net of income taxes					

Net Income/(Loss)	$ 991	$(42)	$ 784	$ (949)	$784

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Nine Months Ended September 30, 2008

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (a)	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 5,020	$ 306	$	$ (18)	$ 5,308
Operating Costs and Expenses					
Cost of operations	2,600	231		(19)	2,812
Depreciation and amortization	454	21	3		478
General and administrative	47	10	176		233
Development costs	(3)	5	27		29
Total operating costs and expenses	3,098	267	206	(19)	3,552
Operating Income/(Loss)	1,922	39	(206)	1	1,756
Other Income/(Expense)					
Equity in earnings/(losses) of consolidated subsidiaries	262		1,347	(1,609)	
Equity in (losses)/earnings of unconsolidated affiliates	(2)	37			35
Other income/(expense), net	19	10	(14)	(1)	14
Interest expense	(148)	(95)	(238)		(481)
Total other income/(expense)	131	(48)	1,095	(1,610)	(432)
Income/(Losses) From Continuing Operations Before Income Taxes	2,053	(9)	889	(1,609)	1,324
Income tax expense/(benefit)	699	5	(173)		531
Income/(Losses) From Continuing Operations	1,354	(14)	1,062	(1,609)	793
Income/(Losses) from discontinued operations, net of income taxes		269	(97)		172

Net Income/(Loss)	$ 1,354	$ 255	$ 965	$ (1,609)	$ 965

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
September 30, 2008

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (a)	Consolidated Balance
		ASSETS			
Current Assets					
Cash and cash equivalents	$ 2	$ 182	$ 1,299	$	$ 1,483
Restricted cash	1	31			32
Accounts receivable, net	487	44			531
Inventory	444	12			456
Derivative instruments valuation	4,190				4,190
Cash collateral paid in support of energy risk management activities	544				544
Prepayments and other current assets	79	35	382	(293)	203
Total current assets	5,747	304	1,681	(293)	7,439
Net property, plant and equipment	10,752	696	24		11,472
Other Assets					
Investment in subsidiaries	659	19	10,936	(11,614)	
Equity investments in affiliates	26	402			428
Notes receivable and capital lease, less current portion	535	450	2,889	(3,424)	450
Goodwill	1,786				1,786
Intangible assets, net	808	14			822
Nuclear decommissioning trust	333				333
Derivative instruments valuation	816				816
Other non-current assets	6	3	125		134
Intangible assets held-for-sale	3				3
Total other assets	4,972	888	13,950	(15,038)	4,772
Total Assets	$ 21,471	$ 1,888	$ 15,655	$ (15,331)	$ 23,683

LIABILITIES AND STOCKHOLDERS EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 83	$ 90	$ 31	$ (82)	$ 122
Accounts payable	(293)	648	12		367
Derivative instruments valuation	4,011	10	1		4,022
Deferred income taxes		19	(3)		16
Cash collateral received in support of energy risk management activities	154				154
Accrued expenses and other current liabilities	422	36	381	(210)	629
Total current liabilities	4,377	803	422	(292)	5,310
Other Liabilities					
Long-term debt and capital leases	2,808	824	7,852	(3,425)	8,059
Nuclear decommissioning reserve	320				320
Nuclear decommissioning trust liability	252				252
Deferred income taxes	659	(172)	596		1,083
Derivative instruments valuation	1,089	17	52		1,158
Out-of-market contracts	336				336
Other non-current liabilities	360	65	143		568
Total non-current liabilities	5,824	734	8,643	(3,425)	11,776
Total liabilities	10,201	1,537	9,065	(3,717)	17,086
Minority interest	7				7
3.625% Preferred Stock			247		247
Stockholders Equity	11,263	351	6,343	(11,614)	6,343
Total Liabilities and Stockholders Equity	$ 21,471	$ 1,888	$ 15,655	$ (15,331)	$ 23,683

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

36

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2008

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (a)	Consolidated Balance
Cash Flows from Operating Activities					
Net income	$1,354	$ 255	$ 965	$ (1,609)	$ 965
Adjustments to reconcile net income to net cash provided by operating activities:					
Distributions and equity in (earnings)/losses of unconsolidated affiliates and consolidated subsidiaries	(260)	(26)	(1,347)	1,609	(24)
Depreciation and amortization	454	21	3		478
Amortization of nuclear fuel	31				31
Amortization of financing costs and debt discount		5	17		22
Amortization of intangibles and out-of-market contracts	(226)				(226)
Changes in deferred income taxes and liability for unrecognized tax benefits	102	(21)	346		427
Changes in nuclear decommissioning liability	8				8
Changes in derivatives	(101)	(9)			(110)
Changes in collateral deposits supporting energy risk management activities	(320)				(320)
Loss on disposal and sales of assets	13				13
Gain on sale of discontinued operations		(273)			(273)
Gain on sale of emission allowances	(52)				(52)
Amortization of unearned equity compensation			21		21
Cash provided by/(used by) changes in other working capital	473	52	(444)		81
Net Cash Provided (Used) by Operating Activities	1,476	4	(439)		1,041

Cash Flows from Investing Activities					
Intercompany (loans to)/receipts from subsidiaries	(175)		885	(710)	
Capital expenditures	(444)	(200)	(5)		(649)
Increase in restricted cash		(3)			(3)
Decrease in notes receivable		35	(15)		20
Purchases of emission allowances	(6)				(6)
Proceeds from sale of emission allowances	75				75
Investment in nuclear decomissioning trust fund securities	(441)				(441)
Proceeds from sales of nuclear decomissioning trust fund securities	434				434
Proceeds from sale of discontinued operations, net of cash divested		(59)	300		241
Proceeds from sale of assets	14				14
Equity investments in unconsolidated affiliates			(17)		(17)
Net Cash Provided (Used) by Investing Activities	(543)	(227)	1,148	(710)	(332)
Cash Flows from Financing Activities					
(Payments)/proceeds for intercompany loans	(882)	208	(36)	710	
Payments for dividends to preferred stockholders			(41)		(41)
Payment of financing element of acquired derivatives	(49)				(49)
Payments for treasury stock			(185)		(185)
Proceeds from issuance of common stock, net of issuance costs			8		8
Proceeds from sale of minority interest in subsidiary		50			50
Proceeds from issuance of long-term debt		20			20
Payments for deferred debt issuance costs			(2)		(2)
Payments for short and long-term debt		(36)	(166)		(202)
Net Cash Provided (Used) by Financing Activities	(931)	242	(422)	710	(401)
Change in cash from discontinued operations		43			43

Effect of exchange rate changes on cash and cash equivalents					
Net Increase in Cash and Cash Equivalent	2	62	287		351
Cash and Cash Equivalents at Beginning of Period		120	1,012		1,132
Cash and Cash Equivalents at End of Period	$ 2	$ 182	$ 1,299	$	$ 1,483

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Three Months Ended September 30, 2007

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (a)	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 1,676	$ 96	$	$	$ 1,772
Operating Costs and Expenses					
Cost of operations	868	73	(2)		939
Depreciation and amortization	153	4	3		160
General and administrative	34	5	39		78
Development costs	30	1	18		49
Total operating costs and expenses	1,085	83	58		1,226
Gain/(Loss) on sale of assets	(1)		1		
Operating Income/(Loss)	590	13	(57)		546
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	60		359	(419)	
Equity in (losses)/earnings of unconsolidated affiliates	1	18			19
Other income, net	3	3	13	(5)	14
Interest expense	(60)	(19)	(95)	5	(169)
Total other income/(expense)	4	2	277	(419)	(136)
Income From Continuing Operations Before Income Taxes	594	15	220	(419)	410
Income tax expense/(benefit)	216	(23)	(48)		145
Income From Continuing Operations	378	38	268	(419)	265
Income from discontinued operations, net of income taxes		3			3

Net Income	$ 378	$ 41	$ 268	$ (419)	$ 268

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
For the Nine Months Ended September 30, 2007

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (a)	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 4,326	$ 281	$	$	$ 4,607
Operating Costs and Expenses					
Cost of operations	2,346	213	1		2,560
Depreciation and amortization	460	17	4		481
General and administrative	80	14	140		234
Development costs	85	1	22		108
Total operating costs and expenses	2,971	245	167		3,383
Gain/(loss) on sale of assets	16				16
Operating Income/(Loss)	1,371	36	(167)		1,240
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	114		768	(882)	
Equity in (losses)/earnings of unconsolidated affiliates	(2)	42			40
Other income, net	7	22	30	(15)	44
Refinancing expense			(35)		(35)
Interest expense	(198)	(63)	(274)	15	(520)
Total other income/(expense)	(79)	1	489	(882)	(471)
Income From Continuing Operations Before Income Taxes	1,292	37	322	(882)	769
Income tax expense/(benefit)	472	(12)	(160)		300
Income From Continuing Operations	820	49	482	(882)	469
Income from discontinued operations, net of income taxes		13			13

Net Income	$	820	$	62	$	482	$	$	(882)	$	482

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING BALANCE SHEETS
December 31, 2007

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy Inc.	Eliminations (a)	Consolidated Balance
ASSETS					
Current Assets					
Cash and cash equivalents	$	$ 120	$ 1,012	$	$ 1,132
Restricted cash	1	28			29
Accounts receivable, net	445	37			482
Inventory	439	12			451
Deferred income taxes	139	(18)	3		124
Derivative instruments valuation	1,034				1,034
Cash collateral paid in support of energy risk management activities	85				85
Prepayments and other current assets	97	34	195	(152)	174
Current assets discontinued operations		51			51
Total current assets	2,240	264	1,210	(152)	3,562
Net Property, Plant and Equipment	10,828	470	22		11,320
Other Assets					
Investment in subsidiaries	610		9,787	(10,397)	
Equity investments in affiliates	28	397			425
Notes receivable	360	126	3,779	(4,139)	126
Capital lease, less current portion		365			365
Goodwill	1,786				1,786
Intangible assets, net	859	14			873
Intangible assets held-for-sale	14				14
Nuclear decommissioning trust fund	384				384
Derivative instruments valuation	150				150
Other non-current assets	11	1	164		176
Non-current assets discontinued operations		93			93

Total other assets	4,202	996	13,730	(14,536)	4,392
Total Assets	$ 17,270	$ 1,730	$ 14,962	$ (14,688)	$ 19,274
LIABILITIES AND STOCKHOLDERS EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 83	$ 282	$ 184	$ (83)	$ 466
Accounts payable trade	(695)	348	731		384
Derivative instruments valuation	916	1			917
Cash collateral received in support of energy risk management activities	14				14
Accrued expenses and other current liabilities	321	62	145	(69)	459
Current liabilities discontinued operations		37			37
Total current liabilities	639	730	1,060	(152)	2,277
Other Liabilities					
Long-term debt and capital leases	3,773	571	7,690	(4,139)	7,895
Nuclear decommissioning reserve	307				307
Nuclear decommissioning trust liability	326				326
Deferred income taxes	598	(138)	383		843
Derivative instruments valuation	690	16	53		759
Non-current out-of-market contracts	628				628
Other non-current liabilities	377	10	25		412
Non-current liabilities discontinued operations		76			76
Total non-current liabilities	6,699	535	8,151	(4,139)	11,246
Total liabilities	7,338	1,265	9,211	(4,291)	13,523
3.625% Preferred Stock			247		247
Stockholders Equity	9,932	465	5,504	(10,397)	5,504
Total Liabilities and Stockholders Equity	$ 17,270	$ 1,730	$ 14,962	$ (14,688)	$ 19,274

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2007

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (a)	Consolidated Balance
Cash Flows from Operating Activities					
Net income	$ 821	$ 61	$ 482	$ (882)	$ 482
Adjustments to reconcile net income to net cash provided by operating activities:					
Distributions and equity (earnings)/losses of unconsolidated affiliates and consolidated subsidiaries	190	(25)	(466)	278	(23)
Depreciation and amortization	459	20	4		483
Amortization of nuclear fuel	42				42
Amortization of financing costs and debt discount		5	54		59
Amortization of intangibles and out-of-market contracts	(116)	4			(112)
Changes in deferred income taxes	63	(40)	209		232
Changes in nuclear decommissioning trust liability	23				23
Changes in derivatives	41				41
Changes in collateral deposits supporting energy risk management activities	(107)				(107)
Gain on disposal and sale of assets	(16)				(16)
Gain on sale of emission allowances	(31)				(31)
Amortization of unearned equity compensation			19		19
Cash (used)/provided by changes in other working capital	(88)	128	(156)		(116)
Net Cash (Used)/Provided by Operating Activities	1,281	153	146	(604)	976
Cash Flows from Investing Activities					
Intercompany (loans to)/receipts from subsidiaries	(81)	(18)	754	(655)	
Capital expenditures	(210)	(93)	(6)		(309)

Increase in restricted cash		(18)			(18)
Decrease in notes receivable		26			26
Purchases of emission allowances	(152)				(152)
Proceeds from the sale of emission allowances	170				170
Investment in nuclear decommissioning trust fund securities	(193)				(193)
Proceeds from sales of nuclear decommissioning trust fund securities	170				170
Proceeds from the sale of assets	29		28		57
Decrease in trust fund balances	19				19
Other		2	(4)		(2)
Net Cash (Used)/Provided by Investing Activities	(248)	(101)	772	(655)	(232)
Cash Flows from Financing Activities					
Payments/proceeds for intercompany loans	(754)		99	655	
Payments from intercompany dividends	(302)	(302)		604	
Payment for dividends to preferred stockholders			(41)		(41)
Payments for treasury stock			(268)		(268)
Proceeds from issuance of long-term debt			1,411		1,411
Payment of deferred debt issuance costs			(5)		(5)
Payments for short and long-term debt	(1)	(36)	(1,435)		(1,472)
Net Cash (Used)/Provided by Financing Activities	(1,057)	(338)	(239)	1,259	(375)
Effect of Exchange Rate Changes on Cash and Cash Equivalents		7			7
Change in Cash from Discontinued Operations		(16)			(16)
Net Increase/(Decrease) in Cash and Cash Equivalents	(24)	(295)	679		360
Cash and Cash Equivalents at Beginning of Period	20	414	343		777
Cash and Cash Equivalents at End of Period	$ (4)	$ 119	$ 1,022	$	$ 1,137

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

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

Introduction and Overview

NRG Energy, Inc., or NRG, or the Company, is a wholesale power generation company with a significant presence in major competitive power markets in the United States. NRG is primarily engaged in the ownership, development, construction and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the trading of energy, capacity and related products in the United States and select international markets. As of September 30, 2008, NRG had a total global portfolio of 189 active operating generation units at 48 power generation plants, with an aggregate generation capacity of approximately 24,020 MW and approximately 472 MW under construction. Within the United States, NRG has one of the largest and most diversified power generation portfolios in terms of geography, fuel-type and dispatch levels, with approximately 22,940 MW of generation capacity in 177 active generating units at 43 plants. These power generation facilities are primarily located in Texas (approximately 10,815 MW), the Northeast (approximately 7,020 MW), South Central (approximately 2,860 MW), and the West (approximately 2,130 MW) regions of the United States, with approximately 115 MW of additional generation capacity from the Company s thermal assets. NRG s principal domestic power plants consist of a mix of natural gas-, coal-, oil-fired and nuclear facilities, representing approximately 46%, 33%, 16% and 5% of the Company s total domestic generation capacity, respectively. In addition, 15% of NRG s domestic generating facilities have dual or multiple fuel capacity, which allows plants to dispatch with the lowest cost fuel option, and consist primarily of baseload, intermediate and peaking power generation facilities, the ranking of which is referred to as the Merit Order, and also include thermal energy production plants. The sale of capacity and power from baseload generation facilities accounts for the majority of the Company s revenues. 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.

The Company s strategy is reflected in five major initiatives, described below. These initiatives are designed to enable the Company to take advantage of opportunities and surmount the challenges faced by the power industry.

1. ***FOR*NRG** is a companywide effort designed to increase the return on invested capital, or ROIC, through operational performance improvements to the Company s asset fleet, along with a range of initiatives at plants and at corporate offices to reduce costs, or in some cases, monetize or reduce excess working capital and other assets. The *FOR*NRG accomplishments disclosed in NRG s SEC filings and press releases include both recurring and one-time improvements measured from a prior base year. For plant operations, the program measures cumulative current year benefits using current gross margins multiplied by the change in baseline levels of certain key performance indicators. The plant performance benefits include both positive and negative results for plant reliability, capacity, heat rate and station service. During 2007, the Company announced the acceleration and planned conclusion of the *FOR*NRG 1.0 program by bringing forward the previously announced 2009 target of $250 million to 2008. Improvements in reliability throughout the baseload fleet, coupled with higher gross margins, especially in the Texas region, were the drivers of the year-to-date program performance. Through September 2008, the Company has estimated the cumulative value of implemented *FOR*NRG improvements will achieve a value in excess of the established a goal of $250 million by December 31, 2008. The *FOR*NRG 1.0 program was measured from a 2004 baseline, with the exception of the Texas Region where benefits were measured using 2005 as the base year.

   Beginning in January 2009, the Company will transition to *FOR*NRG 2.0 and target an incremental 100 basis point improvement to the Company s return on invested capital by 2012. The initial targets for *FOR*NRG 2.0 will be based upon improvements in the Company s ROIC as measured by increased cash flow. The economic results of

*FOR*NRG 2.0 will focus on: (1) revenue enhancement, (2) cost savings, and (3) asset optimization including reducing excess working capital and other assets. *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 average full year plant key performance indicators for years 2006-2008.

2. ***Repowering*NRG** is a comprehensive portfolio redevelopment program designed to develop, construct and operate new multi-fuel, multi-technology, highly efficient and environmentally responsible generation capacity over the next decade. Through this initiative, the Company anticipates retiring certain existing units and adding new generation to meet growing demand in the Company s core markets, with an emphasis on new capacity that is expected to be supported by long-term hedging programs, including power purchase agreements, or PPAs, and financed with limited or non-recourse project financing.

Table of Contents

3. **econrg** represents NRG s commitment to environmentally responsible power generation. econrg seeks to find ways for NRG to meet the challenges of climate change, clean air and water, and conservation of our natural resources while taking advantage of business opportunities that may inure to NRG as a result of our demonstration and deployment of green technologies. Within NRG, econrg builds upon a foundation in environmental compliance and embraces environmental initiatives for the benefit of our communities, employees and shareholders, such as encouraging investment in new environmental technologies, pursuing activities that preserve and protect the environment and encouraging changes in the daily lives of our employees.

4. **Future NRG** is the Company s workforce planning and development initiative and represents NRG s strong commitment to planning for future staffing requirements to meet the on-going needs of the Company s current operations in addition to the Company s *Repowering*NRG initiatives. Future NRG encompasses analyzing the demographics, skill set and size of the Company s workforce in addition to the organizational structure with a focus on succession planning, training, development, staffing and recruiting needs. Included under the Future NRG umbrella is NRG University, which provides leadership, managerial, supervisory and technical training programs and individual skill development courses.

5. **NRG Global Giving** Respect for the community is one of NRG s core values. Our Global Giving Program invests NRG s resources to strengthen the communities where we do business and seeks to make community investments in four FOCUS areas: community and economic development, education, environment and human welfare.

NRG s 2007 Annual Report on Form 10-K includes a detailed discussion of various items impacting its business, results of operations and financial condition. These include:

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 section.

Critical accounting policies 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 revenue recognition and 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, and contingencies.

This discussion and analysis explains the general financial condition and the results of operations for NRG, including:

factors which affect the business;

earnings and costs in the periods presented;

changes in earnings and costs between periods;

sources of earnings;

impact of these factors on NRG s overall financial condition;

expected future expenditures for capital projects; and

expected sources of cash for further operations and capital expenditures.

Table of Contents

As you read this discussion and analysis, refer to the consolidated statements of income which present the results of operations for the three and nine months ended September 30, 2008 and 2007. NRG analyzes and explains the differences between periods in the specific line items of the consolidated statements of income.

NRG has organized the discussion and analysis as follows:

changes to the business environment during the period;

results of operations beginning with an overview of NRG s consolidated results, followed by a more detailed discussion of those results by major operating segment;

financial condition, addressing liquidity, the sources and uses of cash, capital resources and commitments; and

known trends that will affect NRG s results of operation and financial condition in the future.

Changes in Accounting Standards

See Note 1 to the condensed consolidated financial statements of this Form 10-Q as found in Item 1 for a discussion of recent accounting developments.

Business Environment Financial Credit Market Availability and Domestic Recessionary Pressures

A sharp economic downturn in the US and overseas during the latter part of 2008 was prompted by a combination of factors: tight credit markets, speculation and fear regarding the health of the US and global financial systems, and weaker economic activity in general prompting fears of an economic recession. Power generation companies are capital intensive and, as such, rely on the credit markets for liquidity and for the financing of power generation investments. In addition, economic recessions historically result in lower power demand, power prices, and fuel prices. NRG has a diversified liquidity program, with $3.0 billion in total liquidity, and a first and second lien structure that enables significant strategic hedging while reducing requirements for the posting of cash or letters of credit as collateral. NRG expects to continue to manage commodity price volatility through its strategic hedging program, under which the Company expects to hedge revenues and fuel costs. This program should provide the Company with the flexibility to enter into hedges opportunistically, such as when gas prices are increasing, while at the same time protecting NRG against longer-term volatility in the commodity markets. The Company believes that an economic recession is unlikely to have material impact on the Company s cash generation in the near term due to the hedged position of its portfolio. NRG transacts with a diversified pool of counterparties and actively manages our exposure to any single counterparty. See Part 1, Item 1 *Liquidity and Capital Resources*, and Part 1, Item 3 *Quantitative and Qualitative Disclosures about Market Risk* for further discussion.

Unsolicited Exelon Proposal

On October 19, 2008, NRG received an unsolicited proposal from Exelon Corporation to acquire all of the outstanding shares of NRG at a fixed exchange ratio of 0.485 Exelon shares for each NRG common share. NRG s Board of Directors is reviewing Exelon s proposal with their advisors and will determine the appropriate response in due course. As of the date of the filing of this quarterly report, NRG stockholders have been advised to take no action at this time pending the review by NRG s Board of Directors.

Environmental Matters

Carbon Update

At the national level and at various regional and state levels, policies are under development to regulate GHG emissions, including CO_2, thereby effectively putting a cost on such emissions in order to create financial incentives to reduce them. The Northeast states are furthest along where six of ten participating states held the first CO_2 allowances auction on September 25, 2008. The effective start date is January 1, 2009. California under legislation enacted in 2007 known as AB32, the seven states and four Canadian provinces in the Western Climate Initiative, and the six states in the Midwest GHG Accord continue to develop market based programs for their respective jurisdictions. It is almost certain that all GHG regulatory schemes will encompass power plants. The impact on the Company s financial performance will depend on a number of factors, including the overall level of GHG reductions required under any such regulation, the price and availability of offsets, and the extent to which NRG would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market. Despite current fiscal and economic concerns, Congressional leaders continue to seek an approach to national climate change legislation that will gain the support necessary to become law. In October 2008, Representatives Boucher and Dingell introduced a climate change discussion draft into Congress that, along with basic cap and trade architecture, offers a menu of options for dealing with a number of important details

44

such as allocations and factors that could affect allowance price. In addition, the climate change discussion draft continues the trend of all major climate legislation in Congress to provide significant support for low carbon investments such as those involved in the Company s *Repowering*NRG and econrg programs. Information regarding the Company s carbon strategy is discussed in greater detail in Part I, Item 1, Carbon Update in NRG Energy, Inc. s 2007 Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

On April 2, 2007, the US Supreme Court issued a decision in Massachusetts v. EPA that the USEPA has authority under Title II of the Clean Air Act or CAA to regulate CO_2 emissions from new motor vehicles. The actual treatment of CO_2 under the CAA is contingent upon an official finding by the USEPA on whether these emissions endanger public health and the environment. While such a finding, based on the Supreme Court decision, would be specific to mobile sources, the outcome would also be applicable to the regulation of stationary sources including electric generating units. On July 30, 2008, the USEPA released an Advance Notice of Proposed Rulemaking, or ANPR, inviting public comment on the benefits and ramifications of regulating GHG emissions under the CAA with comments due to EPA by November 28, 2008. Given this schedule it appears unlikely that there will be any regulation of CO_2 under the CAA during the remainder of 2008. At this time, NRG cannot predict the outcome of the ANPR process, any resulting changes to federal regulations, nor the impact on Company operations.

Federal Environmental Initiatives

On May 18, 2005, the USEPA published the Clean Air Mercury Rule, or CAMR, to permanently cap and reduce mercury emissions from coal-fired power plants. CAMR imposed limits on mercury emissions from new and existing coal-fired plants and created a market-based cap-and-trade program to reduce nationwide emissions of mercury. The rule was challenged by New Jersey and ten other states. On February 8, 2008, the US Court of Appeals for the D.C. Circuit vacated USEPA s rule delisting coal- and oil-fired electric generating units from regulation under CAA § 112, or the Delisting Rule, and CAMR. Power plant emissions are now subject to Section 112 of the CAA which requires installation of maximum achievable control technology, or MACT, to reduce emissions. The USEPA plans to develop MACT standards and existing power plants will need to provide plans to meet the new requirements. Certain states in which NRG operates coal plants, such as Delaware, Massachusetts and New York, adopted state implementation plans in lieu of the CAMR federal implementation plan and these state rules remain unchanged. Texas and Louisiana adopted the federal CAMR.

On May 12, 2005, the USEPA published the market based Clean Air Interstate Rule, or CAIR. This rule applied to 28 eastern states and the District of Columbia, or D.C., and capped both SO_2 and NO_x emissions from power plants in two phases; 2010 and 2015 for SO_2 and 2009 and 2015 for NO_x. CAIR applies to some of the Company s power plants in New York, Massachusetts, Connecticut, Delaware, Louisiana, Illinois, Pennsylvania, Maryland and Texas. On July 11, 2008, the D.C. Circuit Court ruled that CAIR should be vacated in its entirety. The USEPA petitioned for rehearing *en banc* on September 24, 2008. The D.C. Circuit Court must grant or deny the petition over the next few months after which it will be reheard or the USEPA can appeal for a hearing before the Supreme Court. The Court has not yet stayed the rule leaving January 1, 2009 as the effective date for the CAIR annual and seasonal NO_x trading program. NRG s SO_2 and NO_x plans are driven primarily by state requirements and consent orders. NRG s estimate for environmental capital expenditures reflects changes in schedule and design related to the current status of both CAIR and CAMR. The timing and substantive provisions of any ensuing revised or replacement regulations or legislation may alter the composition and rate of spending for environmental retrofits at our facilities.

On September 30, 2008, the NRG Texas region held a bank of emissions allowances with a net carrying value of $748 million, consisting of $504 million for SO_2 and $244 million for NO_x. These are classified as long-term intangible assets and are carried at average cost. The D.C. Circuit Court ruling has resulted in a decline in current SO_2 market prices. NRG has estimated its SO_2 allowance requirement needed for generation based on the new ruling and evaluated any excess SO_2 allowances for potential impairment. Variability in generation assumptions and any ensuing regulations or legislation will alter our assumed rate of excess SO_2 allowances. NRG does not expect that CAIR and the D.C. Circuit Court ruling will have a material impact on the carrying value of our excess SO_2 allowances.

On March 12, 2008, the USEPA strengthened the primary and secondary ground level ozone National Ambient Air Quality Standards, or NAAQS, (eight hour average) from 0.08 ppm to 0.075 ppm. The USEPA plans to finalize ozone non-attainment regions by March 2010 and states would likely submit plans to come into attainment by 2013. The Company is unable to predict with certainty the impact of the states future recommendations on NRG s operations.

Regional Environmental Initiatives

Northeast Region On December 20, 2005, 10 northeastern states entered into a Memorandum of Understanding, or MOU, to create the Regional Greenhouse Gas Initiative, or RGGI, to establish a cap-and-trade GHG program for electric generators. Electric generating units in participating RGGI states will have to procure one allowance for every US ton of CO_2 emitted with true up for 2009-2011 occurring in 2012. NRG units located in Connecticut, Delaware, Maryland, Massachusetts and New York emitted approximately 13 million US tons of CO_2 in 2007. NRG believes that to the extent allowance costs will not be fully reflected in wholesale electricity prices, the direct financial impact on the Company is likely to be negative as costs are incurred to secure the necessary RGGI allowances and offsets at auction and in the market.

Regulatory Matters

As an operator of power plants and a participant in the wholesale markets, NRG is subject to regulation by various federal and state government agencies. In addition, NRG is subject to the market rules, procedures, and protocols of the various ISO markets in which NRG participates. These wholesale power markets are subject to ongoing legislative and regulatory changes. In some of NRG s regions, interested parties have advocated for material market design changes, including the elimination of a single clearing price mechanism, as well as proposals to re-regulate the markets or require divestiture by generating companies in order to reduce their market share. The Company cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on NRG s business.

Northeast Region

New England On July 1, 2008, ISO-NE filed proposed revisions to its market rules tariff addressing the compensation for units needed for reliability purposes after June 1, 2010 (the scheduled date for the implementation of the forward capacity market). These rule changes will impact NRG s units that have operated pursuant to RMR agreements and that seek to delist in the forward capacity auctions such as Norwalk Power s units 1 and 2 which submitted a delist bid in the first forward capacity auction. On October 28, 2008, FERC determined that units, such as Norwalk Power s units, that submitted a dynamic delist bid that was rejected by ISO-NE for reliability reasons should be required to operate at their bid amount, not a cost of service rate, notwithstanding mitigation rules that restricted the ability of the units to submit a higher delist bid. As a result, the Norwalk Power units will be compensated at their delist bid of $5.99/kw-mo. for the first FCM capacity year.

On October 20, 2008, Northeast Utilities Service Company, or NU, the parent company of Connecticut Light and Power, filed an application with the Connecticut Siting Council for the Greater Springfield Reliability component of the New England East-West Solution, or NEEWS, transmission project, a significant reinforcement of the 345 kV transmission system. If constructed, the NEEWS line will increase the import capacity into Connecticut by approximately 1,100 MW.

New York On March 7, 2008, FERC issued an order accepting the NYISO s proposed market reforms to the in-city Installed Capacity, or ICAP, market, with only minor modifications. The NYISO proposal retains the existing ICAP market structure, but imposes additional market power mitigation on the current owners of Consolidated Edison s divested generation units in New York City (which include NRG s Arthur Kill and Astoria facilities), who are deemed to be pivotal suppliers. Specifically, the NYISO proposal imposes a new reference price on pivotal suppliers and requires bids to be submitted at or below the reference price. The new reference price is derived from the expected clearing price based upon the intersection of the supply curve and the ICAP Demand Curve if all suppliers bid as price-takers. The NYISO s proposed reforms became effective March 27, 2008.

Texas Region

ERCOT has adopted Texas Nodal Protocols that will revise the wholesale market design to incorporate locational marginal pricing (in place of the current ERCOT zonal market). Major elements of the Texas Nodal Protocols include the continued capability for bilateral contracting of energy and ancillary services, a financially binding day-ahead market, resource-specific energy and ancillary service bid curves, the direct assignment of all congestion rents, nodal energy prices for resources, aggregation of nodal to zonal energy prices for loads, congestion revenue rights (including pre-assignment for public power entities), and pricing safeguards. The Public Utility Commission of Texas, or PUCT, approved the Texas Nodal Protocols on April 5, 2006, and full implementation of the new market design was scheduled to begin in 2008. On May 20, 2008, ERCOT announced that it would delay the implementation of the Texas Nodal Protocols, and has not provided a new target implementation date.

In May 2008, the ERCOT real-time energy market experienced periods of high prices as a result of limited intervals during which two zonal constraints were simultaneously binding, and this congestion was irresolvable through the dispatch of available resources. In response, ERCOT enacted revised protocols, effective June 9, 2008, for addressing such zonal congestion, providing ERCOT with greater authority to manage such congestion through the use of out-of-market mechanisms towards the goal of lowering prices. In addition, on June 17, 2008, ERCOT enacted revisions to its price cap procedures in order to further dampen the volatility and high prices. Thus, it is unlikely that the circumstances contributing to the price spikes of May 2008 will be repeated.

On July 17, 2008, as part of its determination of Competitive Renewable Energy Zones, or CREZ, the PUCT approved a significant transmission expansion plan to provide for the delivery of approximately 18,500 MW of energy from the western region of Texas, primarily wind generation. The schedule for construction of the transmission upgrades (approximately 2,300 miles of new 345 kV lines and 42 miles of new 138 kV lines) will be determined in subsequent PUCT proceedings. If completed as currently approved, the transmission upgrades and associated wind generation could impact wholesale energy and ancillary service prices in ERCOT. The PUCT issued its written order on August 15, 2008.

West Region

CAISO has indicated that its Market Redesign and Technology Upgrade, or MRTU, program will not be implemented before February 1, 2009. Significant components of the MRTU include: (i) locational marginal pricing of energy; (ii) a more effective congestion management system; (iii) a day-ahead market; and (iv) an increase to the existing bid caps. NRG considers these market reforms to be a positive development for its assets in the region.

On October 22, 2008, FERC issued a definitive order regarding the provision of station power in California. The FERC s order reaffirmed the right of generators to engage in monthly netting of their station power needs and, further, clarified that local transmission-owning utilities are preempted from imposing state-based charges on such generators. This order should allow the Company to engage in monthly netting and thus avoid buying power at retail for many of its stations and, further, to avoid the other charges that the local transmission-owning utilities have been imposing. The Company is proceeding with preparation of a station power plan for submission to the California Public Utility Commission, or CPUC, and expects to realize savings in operation costs as a result of this order.

Table of Contents

Consolidated Results of Operations

The following table provides selected financial information for the Company:

	Three months ended September 30,			Nine months ended September 30,		
(In millions except otherwise noted)	**2008**	**2007**	**Change%**	**2008**	**2007**	**Change%**
Operating Revenues						
Energy revenue	$ 1,373	$ 1,264	9%	$ 3,671	$ 3,255	13%
Capacity revenue	356	328	9	1,037	890	17
Risk management activities	822	35	N/A	105	44	139
Contract amortization	76	66	15	233	185	26
Thermal revenue	26	27	(4)	85	97	(12)
Other revenues	37	52	(29)	177	136	30
Total operating revenues	2,690	1,772	52	5,308	4,607	15
Operating Costs and Expenses						
Cost of operations	997	939	6	2,812	2,560	10
Depreciation and amortization	156	160	(3)	478	481	(1)
General and administrative	75	78	(4)	233	234	
Development costs	13	49	(73)	29	108	(73)
Total operating costs and expenses	1,241	1,226	1	3,552	3,383	5
Gain on sale of assets					16	N/A
Operating income	1,449	546	165	1,756	1,240	42
Other Income/(Expense)						
Equity in earnings of unconsolidated affiliates	58	19	205	35	40	(13)
Other (loss)/income, net	(7)	14	(150)	14	44	(68)
Refinancing expense					(35)	N/A
Interest expense	(186)	(169)	10	(481)	(520)	(8)
Total other expense	(135)	(136)	(1)	(432)	(471)	(8)
Income from Continuing Operations before income tax expense	1,314	410	220	1,324	769	72
Income tax expense	530	145	266	531	300	77

Income from Continuing Operations		784		265	196		793		469	69
Income from discontinued operations, net of income tax expense				3	N/A		172		13	N/A
Net Income	$	784	$	268	193	$	965	$	482	100
Business Metrics										
Average natural gas price Henry Hub ($/MMBtu)		9.11		6.24	46%		9.67		7.02	38%

N/A Not Applicable

Management s discussion of the results of operations for the three months ended September 30, 2008 and 2007:

Operating Revenues

Operating revenues increased $918 million during the three months ended September 30, 2008 compared to the same period in 2007.

Energy revenues increased $109 million during the three months ended September 30, 2008 compared to the same period in 2007:

o *Texas* increased $70 million, with $101 million of this increase driven by higher energy prices, offset by $31 million resulting from lower generation volumes. Energy price increases were due to a more favorable mix of merchant versus contract sales, as well as a 30% increase in merchant prices partially offset by a 14% decrease in contract energy prices. Coal plant generation increased by 1%, while gas plant generation decreased by 26%, attributable to the effects of hurricane Ike in September 2008.

Table of Contents

- o *Northeast* increased $5 million, with $49 million driven by higher energy prices, offset by a $44 million decrease attributable to a reduction in generation. Higher energy prices were due to an average 19% rise in merchant prices offset by lower contract revenue of $11 million driven by higher costs required to service the PJM contracts, as a result of the increase in market energy prices. Generation decreased 12% due to a cooler summer in 2008 as compared to 2007.

- o *South Central* increased $19 million, attributable to higher merchant energy revenues, reflecting a 40% rise in on-peak power prices combined with a 19% increase in merchant energy MWh sold.

- o *West* increased $11 million due to the dispatch of the El Segundo plant outside of its tolling agreement in 2008. In 2007, no such dispatch occurred.

Capacity revenues increased $28 million during the three months ended September 30, 2008 compared to the same period in 2007:

- o *Texas* increased $39 million due to a greater proportion of base-load contracts, which contain a capacity component.

- o *Northeast* decreased $9 million, as lower capacity prices in the NYISO and PJM markets were offset by higher capacity prices in the NEPOOL markets.

Other revenues decreased $15 million during the three months ended September 30, 2008 compared to the same period in 2007, driven by reduced activity in trading gas and coal of $31 million, offset by a $12 million increase in ancillary revenue.

Risk management activities revenues from risk management activities include economic hedges that did not qualify for cash flow hedge accounting, ineffectiveness on cash flow hedges, and trading activities. Such revenues increased by $787 million during the three months ended September 30, 2008 compared to the same period in 2007. The breakdown of changes by region is as follows:

	Three months ended September 30, 2008				**Three months ended September 30, 2007**			
(In millions)	**Texas**	**Northeast**	**South Central**	**Total**	**Texas**	**Northeast**	**South Central**	**Total**
Net gains/(losses) on settled positions, or *financial revenues*	$ 3	$ 22	$ (4)	$ 21	$ 15	$ 13	$ 1	$ 29
Mark-to-market results								
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	(5)	(2)		(7)	(15)	(2)		(17)
Reversal of previously recognized unrealized gains on settled positions related to		(6)	(3)	(9)	(1)	3	(5)	(3)

trading activity								
Net unrealized gains/(losses) on open positions related to economic hedges	590	201		791	1	9		10
Net unrealized gains/(losses) on open positions related to trading activity	(12)	8	30	26	(4)	5	15	16
Subtotal mark-to-market results	573	201	27	801	(19)	15	10	6
Total gain/(loss)	$ 576	$ 223	$ 23	$ 822	$ (4)	$ 28	$ 11	$ 35

NRG s third quarter 2008 gain is comprised of $801 million of mark-to-market gains and $21 million in settled gains, or financial revenue. Of the $801 million of mark-to-market gains, $7 million represents the reversal of mark-to-market gains recognized on economic hedges and $9 million represents the reversal of mark-to-market gains recognized on trading activity during 2007. Both of these losses ultimately settled as financial revenues during 2008. The $791 million gain from economic hedge positions included a $439 million increase in value of forward sales of electricity and fuel due to lower forward power and gas prices and a $352 million gain primarily from hedge accounting ineffectiveness related to gas trades in the Texas region which was driven by decreasing forward gas prices while forward power prices decreased at a slower pace.

Since these hedging activities are intended to mitigate the risk of commodity price movements on revenues, the changes in such results should not be viewed in isolation, but rather should be taken together with the effects of pricing and cost changes on energy revenues. During and prior to 2007, NRG hedged a portion of the Company s 2007 and 2008 generation. During the third quarter 2007 and 2008 the settled and forward prices of electricity and natural gas have decreased resulting in the recognition of realized gains and unrealized mark-to-market gains.

Cost of Operations

Cost of operations increased $58 million during the three months ended September 30, 2008 compared to the same period in 2007.

Cost of energy increased $45 million during the three months ended September 30, 2008 compared to the same period in 2007 due to:

- *Texas* increased $8 million due to higher natural gas, coal, and ancillary service costs, offset by lower nuclear fuel expense and amortized contract costs. Natural gas cost increased $22 million, reflecting a 45% rise in per MMBtu average natural gas prices, offset by a 26% decrease in gas-fired generation. Coal costs increased $3 million due to higher coal prices. Ancillary service costs rose $11 million due to increased purchases to meet contract obligations and a rise in ancillary service costs incurred by ERCOT. Nuclear fuel expense decreased $15 million as amortization of nuclear fuel inventory established under Texas Genco purchase accounting ended in 2008. Amortized contract costs decreased $11 million as amortization of water supply contracts established under Texas Genco purchase accounting ended in 2007.

- *Northeast* decreased $1 million as a $15 million reduction in natural gas costs and a $2 million reduction in oil costs were offset by a $16 million increase in coal costs. Natural gas cost decreased due to 26% lower generation offset by higher average prices. Coal costs increased due to higher prices and fuel transportation surcharges offset by 4% lower coal generation.

- *South Central* increased $25 million due to a $14 million increase in purchased energy reflecting higher gas costs, and a $12 million increase in natural gas costs as certain gas plants ran extensively to support transmission system stability during hurricane Gustav.

- *West* increased $10 million due to the dispatch of the El Segundo plant outside of the tolling agreement in 2008. In 2007, no such dispatch occurred.

Other operating costs increased $13 million during the three months ended September 30, 2008 compared to the same period in 2007, due to increased operating and maintenance expenses, as well as higher diesel and chemical costs in the Texas region.

Development Costs

NRG s development costs arise from *Repowering*NRG projects and were $13 million for the three months ended September 30, 2008, a decrease of $36 million when compared to the same period in 2007:

Texas STP units 3 and 4 projects No development expense was reflected in results of operations for the third quarter 2008 period as NRG began to capitalize STP units 3 and 4 development costs incurred after January 1, 2008 following the NRC s docketing of the Company s Combined Operating License Application, or COLA, in late 2007. The Company recorded $35 million in development expenses during the same period in 2007.

Wind projects the Company incurred $4 million in development costs related to wind projects in Texas and California which is a $1 million decrease from the same period in 2007.

Other projects the Company incurred $9 million in development costs related to other domestic *Repowering*NRG projects which is consistent with the same period in 2007.

Equity in Earnings of Unconsolidated Affiliates

NRG s equity earnings from unconsolidated affiliates increased by $39 million for the three months ended September 30, 2008 compared to the same period in 2007. This increase was due to a $41 million mark-to-market unrealized gain on a forward contract for natural gas swap executed to hedge the future power generation of Sherbino.

Other (Loss)/Income, Net

NRG s other (loss)/income decreased by $21 million for the three months ended September 30, 2008 compared to the same period in 2007. The Company recorded an additional $19 million impairment charge in the third quarter 2008 to restructure distressed investments in commercial paper, as previously disclosed in 2007, reducing its carrying value to $10 million.

Interest Expense

NRG s interest expense increased by $17 million for the three months ended September 30, 2008 compared to the same period in 2007. This increase was due to the $45 million payment made to CS for the benefit of CSF I in August 2008 to early settle the embedded derivative in the Company s CSF I notes and preferred interests. This increase was offset by decreases due to interest savings from the $300 million prepayment in December 2007 and an additional payment of $143 million in March 2008 of the Term B loan in connection with the mandatory offer under the Senior Credit Facility accompanied by a reduction on the variable interest rates on long-term debt. Interest capitalized on *Repowering*NRG projects under construction also contributed to this decrease.

Income Tax Expense

NRG s income tax expense increased by $385 million for the three months ended September 30, 2008 compared to the same period in 2007. The effective tax rate was 40.3% and 35.4% for the three months ended September 30, 2008 and 2007, respectively. The increase in income tax expense was primarily due to an increase in income.

(In millions except percentages) **Three months ended September 30,**	**2008**	**2007**
Income from continuing operations before income taxes	$ 1,314	$ 410
Tax at 35%	460	143
State taxes, net of federal benefit	63	21
Foreign operations	(2)	(4)
Foreign dividends		13
Non-deductible interest	18	2
Change in German tax rate		(30)
Section 199 Manufacturing Deduction	(11)	(3)
Other permanent differences	2	3
Income tax expense	$ 530	$ 145
Effective income tax rate	40.3%	35.4%

The increase in income tax expense was due to:

Increase in income pre-tax income increased by $904 million with a corresponding increase of $358 million in income tax expense.

Permanent differences the Company s effective tax rate differed from the US statutory rate of 35% due to:

- o *Taxable dividends from foreign subsidiaries* US taxability of foreign subsidiaries earnings resulted in an additional tax benefit of approximately $13 million during the third quarter 2008 as compared to 2007.
- o *Non-deductible interest on CSF I CAGR Settlement* the Company executed the Note Purchase Amendment Agreement and Preferred Interest Amendment Agreement which allowed CSF I to early settle the CSF I CAGR. The result of this settlement resulted in an additional income tax expense of $16 million during the third quarter 2008 as compared to the same period in 2007.
- o *Change in German tax rate* due to a reduction in the German effective tax rate, income tax expense benefited by $30 million in 2007 as compared to the same period in 2008.
- o *Section 199 Manufacturing Deduction* as a result of the increase in pre-tax income during 2008, the Company recorded an additional income tax benefit of $8 million as compared to 2007.

The effective income tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and changes in valuation allowances in accordance with SFAS 109. These factors and others, including the Company s history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Income from Discontinued Operations, Net of Income Tax Expense

Discontinued operations included ITISA results for the three months ended September 30, 2007. NRG classifies as discontinued operations the income from operations and gains/losses recognized on the sale of projects that were sold or have met the required criteria for such classification pending final disposition. For the three months ended September 30, 2007, NRG recorded income from discontinued operations, net of income tax expense, of $3 million. NRG closed the sale of ITISA during the second quarter 2008.

Management s discussion of the results of operations for the nine months ended September 30, 2008 and 2007:

Operating Revenues

Operating revenues increased $701 million during the nine months ended September 30, 2008 compared to the same period in 2007.

Energy revenues increased $416 million during the nine months ended September 30, 2008 compared to the same period in 2007:

o *Texas* increased $291 million, was driven by higher prices, as generating volumes were essentially unchanged. The price variance was attributable to a more favorable mix of merchant versus contract sales, as well as a 38% increase in merchant prices partially offset by a 14% decrease in contract energy prices. Total generation was largely unchanged at 36 million MWh. The mix of generation however did change with a 3% higher generation from the nuclear plant and a less than 1% rise in generation from coal plants. This mix was offset by a 7% reduction in gas plant generation, attributable to the effects of hurricane Ike in September 2008.

o *Northeast* increased $28 million, with $57 million of the increase driven by higher energy prices, offset by $29 million due to reduced generation. The increase due to energy prices reflects an average 12% rise in merchant energy prices offset by lower contract revenue, driven by higher costs required to service the PJM contracts, as a result of the increase in market energy prices. The decline due to generation was driven by a net 3% reduction in the region s generation, due to a cooler summer and warmer winter in 2008 compared to 2007.

o *South Central* increased $61 million, attributable to $57 million higher merchant energy revenues. The growth in merchant energy revenues reflects a 35% rise in merchant MWh sold, as a 6% decrease in contract load MWh allowed more sales to the merchant market at higher prices.

o *West* increased $23 million due to the dispatch of the El Segundo plant outside of the tolling agreement in 2008. In 2007, no such dispatch occurred.

Capacity revenues increased $147 million during the nine months ended September 30, 2008 compared to the same period in 2007:

o

Texas increased $93 million due to a greater proportion of base-load contracts, which contain a capacity component.

- o *Northeast* increased $26 million reflecting higher capacity revenues in the PJM and NEPOOL markets.

- o *South Central* increased $11 million due to new peak loads set by the region s cooperative customers which resulted in $6 million of additional capacity payments and increased RPM capacity payments of $5 million from the PJM market.

- o *West* increased $10 million due to a tolling arrangement at Long Beach plant.

Contract amortization revenues increased $48 million during the nine months ended September 30, 2008 compared to the same period in 2007 due to the volume of contracted energy affected by a greater spread between contract prices and market prices used in the Texas Genco purchase accounting.

Other revenues increased by $41 million during the nine months ended September 30, 2008 compared to the same period in 2007. The increases arose from greater ancillary services revenue of $30 million and increased activity in the trading of emission allowances and carbon financial instruments of $21 million. These increases were offset by $12 million in lower gas and coal trading activities.

Risk management activities revenues from risk management activities include economic hedges that did not qualify for cash flow hedges, ineffectiveness on cash flow hedge accounting and trading activities. Such revenues increased by $61 million during the nine months ended September 30, 2008 compared to the same period in 2007. The breakdown of changes by region is as follows:

	Nine months ended September 30, 2008				**Nine months ended September 30, 2007**			
(In millions)	**Texas**	**Northeast**	**South Central**	**Total**	**Texas**	**Northeast**	**South Central**	**Total**
Net gains/(losses) on settled positions, or *financial revenues*	$ (47)	$ (2)	$ (4)	$ (53)	$ 31	$ 49	$ 5	$ 85
Mark-to-market results								
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	(21)	(11)		(32)	(69)	(40)		(109)
Reversal of previously recognized unrealized (gains)/losses on settled positions related to trading activity	1	(7)	(14)	(20)		(9)	(14)	(23)
Net unrealized gains/(losses) on open positions related to economic hedges	95	58		153	39	15		54
Net unrealized gains/(losses) on open positions related to trading activity	25	1	31	57	1	8	28	37
Subtotal mark-to-market results	100	41	17	158	(29)	(26)	14	(41)
Total gain/(loss)	$ 53	$ 39	$ 13	$ 105	$ 2	$ 23	$ 19	$ 44

NRG s 2008 gain is comprised of $158 million of mark-to-market gains and $53 million in settled losses, or financial revenue. Of the $158 million of mark-to-market gains, $32 million represents the reversal of mark-to-market gains recognized on economic hedges and $20 million represents the reversal of mark-to-market gains recognized on trading activity during 2007. Both of these losses ultimately settled as financial revenues during 2008. The $153 million gain from economic hedge positions included a $180 million increase in value of forward sales of electricity and fuel due to higher forward power and gas prices and a $27 million loss primarily from hedge accounting ineffectiveness related to gas trades in the Texas region which was driven by increasing forward gas prices while forward power prices rose at a slower pace.

Since these hedging activities are intended to mitigate the risk of commodity price movements on revenues the changes in such results should not be viewed in isolation, but rather should be taken together with the effects of pricing and cost changes on energy revenues. During and throughout 2007, NRG hedged a portion of the Company s 2007 and 2008 generation. Since that time, the settled and forward prices of electricity and natural gas have decreased, resulting in the recognition of unrealized mark-to-market forward gains. In 2007, NRG recognized forward mark-to-market losses as forward prices of electricity increased relative to its forward positions.

Table of Contents

Cost of Operations

Cost of operations increased $252 million during the nine months ended September 30, 2008 compared to the same period in 2007.

Cost of energy increased $260 million during the nine months ended September 30, 2008 compared to the same period in 2007 due to:

- *Texas* increased $132 million due to increases in natural gas costs, coal costs and ancillary services cost, offset by reductions in nuclear fuel expenses and amortization of contracts cost. The $136 million rise in natural gas costs was due to an increase of average natural gas prices, offset by a 7% decrease in gas-fired generation. The $16 million increase in coal costs was a result of the recognition of a settlement related to a coal contract dispute and higher coal prices. The $19 million increase in ancillary services and other costs was the result of higher purchased ancillary services and increased ERCOT ISO fees. Amortized contracts costs decreased by $31 million as the amortization of water supply contracts established under Texas Genco purchase accounting ended in 2007. Nuclear fuel expense decreased by $11 million as amortization of nuclear fuel inventory established under Texas Genco purchase accounting ended in early 2008.

- *Northeast* increased $51 million due to $54 million higher coal costs and $20 million higher natural gas costs, offset by $23 million reduced oil costs. Coal costs increased due to 4% higher generation, as well as higher coal prices and fuel transportation surcharges. Natural gas costs increased due to higher natural gas prices, despite 14% lower generation. Oil costs decreased due to lower oil-fired generation.

- *South Central* increased $43 million due to a $7 million rise in coals costs resulting from an increase in fuel transportation surcharges, a $12 million rise in natural gas costs as the region s peaker plants ran extensively to support transmission system stability after hurricane Gustav, and an $18 million increase in purchased energy, reflecting higher natural gas costs for tolling contracts.

- *West* increased $23 million due to the dispatch of the El Segundo plant outside of the tolling agreement in 2008. In 2007, no such dispatch occurred.

Other operating costs decreased $8 million during the nine months ended September 30, 2008 compared to the same period in 2007. This decrease was due to:

- *Texas* increased $20 million due to higher operating and maintenance expenses, increased chemical and diesel costs at the region s fossil plants, STP equipment retirements and refueling outage, and the timing of annual outages at the WA Parish and Limestone plants.

- *Northeast* decreased $19 million due to a $16 million decrease in operating and maintenance expenses and a $7 million decrease in property taxes. The decrease in operating and maintenance expenses was the result of less outage work at the Arthur Kill, Huntley and Norwalk plants. The reduction in property taxes was due to property tax credits received in 2008.

Development Costs

NRG s development costs that rose from *Repowering*NRG projects were $29 million for the nine months ended September 30, 2008, which is a decrease of $79 million when compared to the same period in 2007:

Texas STP units 3 and 4 projects the Company recorded $7 million of income during the nine months ended September 30, 2008, compared to $74 million in development expenses during the same period in 2007. The 2008 activity reflects an April 2008 reimbursement under a partnership agreement for development costs incurred in 2007. No development expense is reflected in results of operations for the nine months ended September 30, 2008 period as NRG began to capitalize STP units 3 and 4 development costs incurred after January 1, 2008 following the NRC s docketing of the Company s Combined Operating License Application, or COLA, in late 2007.

Wind projects the Company incurred $13 million in development costs related to Texas wind projects, which is a $1 million increase from the same period in 2007.

Other projects the Company incurred $23 million in development costs related to other domestic *Repowering*NRG projects which is a $1 million increase from the same period in 2007.

Gain on Sale of Assets

The Company reported no gains on sales of assets for the nine months ended September 2008. For the nine months ended September 30, 2007, NRG s gain on the sale of assets was $16 million. On January 3, 2007, NRG completed the sale of the Company s Red Bluff and Chowchilla II power plants resulting in a pre-tax gain of $18 million.

Equity in Earnings of Unconsolidated Affiliates

NRG s equity earnings from unconsolidated affiliates decreased by $5 million for the nine months ended September 30, 2008 compared to the same period in 2007. This decrease was due to a $9 million mark-to-market unrealized loss on natural gas swap executed to hedge the future power generation of Sherbino.

Other (Loss)/Income, Net

NRG s other (loss)/income decreased by $30 million for the nine months ended September 30, 2008 compared to the same period in 2007. The Company recorded an additional $22 million impairment charge in 2008 to restructure distressed investments in commercial paper, as previously disclosed in 2007, reducing its carrying value to $10 million. In addition, the 2008 results reflect reduced interest income of $32 million from lower market interest rates on cash deposits.

Refinancing Expense

Refinancing expense decreased by $35 million for the nine months ended September 30, 2008 compared to the same period in 2007. On June 8, 2007, NRG completed a $4.4 billion refinancing of the Company s Senior Credit Facility, resulting in a charge of $35 million from the write-off of deferred financing costs as the lenders for 45% of the Term B loan either exited the financing or reduced their holdings and were replaced by other institutions.

Interest Expense

NRG s interest expense decreased by $39 million for the nine months ended September 30, 2008 compared to the same period in 2007. This decrease was due to interest savings from the $300 million prepayment in December 2007 and an additional payment of $143 million in March 2008 of the Term B loan in connection with the mandatory offer under the Senior Credit Facility accompanied by a reduction on the variable interest rates on long-term debt. Interest capitalized on *Repowering*NRG projects under construction also contributed to this decrease. Offsetting these decreases was the $45 million payment made to CS for the benefit of CSF I in August 2008 to early settle the embedded derivative in the Company s CSF I notes and preferred interests.

Income Tax Expense

NRG s income tax expense increased by $231 million for the nine months ended September 30, 2008 compared to the same period in 2007. The effective tax rate was 40.1% and 39.0% for the nine months ended September 30, 2008 and 2007, respectively. The increase in income tax expense was primarily due to an increase in income.

(In millions except percentages) Nine months ended September 30,	**2008**	**2007**

Income from continuing operations before income taxes	$ 1,324	$ 769
Tax at 35%	463	269
State taxes, net of federal benefit	62	37
Foreign operations	(10)	(5)
Valuation allowance	(1)	1
Foreign dividends	5	21
Non-deductible interest	24	7
Change in German tax rate		(30)
Section 199 Manufacturing Deduction	(17)	(3)
Other permanent differences	5	3
Income tax expense	$ 531	$ 300
Effective income tax rate	40.1%	39.0%

Table of Contents

The increase in income tax expense was due to:

Increase in income pre-tax income increased by $555 million, with a corresponding increase of $220 million in income tax expense.

Permanent differences the Company s effective tax rate differs from the US statutory rate of 35% due to:

- *Lower tax rates in foreign jurisdictions* lower income tax rates at the Company s foreign locations resulted in an income tax benefit in 2008 as compared to the same period in 2007 of $5 million.
- *Taxable dividends from foreign subsidiaries* US taxability of foreign subsidiaries earnings resulted in an additional tax benefit of approximately $16 million in 2008 as compared to 2007.
- *Non-deductible interest on CSFI CAGR Settlement* the Company executed the Note Purchase Amendment Agreement and Preferred Interest Amendment Agreement which allowed CSF I to early settle the CSFI CAGR. The result of this settlement resulted in an additional income tax expense of $16 million in 2008 as compared to the same period in 2007
- *Change in German tax rate* due to a reduction in the German effective tax rate, income tax expense benefited by $30 million in 2007 as compared to the same period in 2008.
- *Section 199 Manufacturing Deduction* as a result of the increase in pre-tax income during 2008, the Company recorded an additional income tax benefit of $14 million as compared to 2007.

The effective income tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and changes in valuation allowances in accordance with SFAS 109. These factors and others, including the Company s history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Income from Discontinued Operations, Net of Income Tax Expense

Discontinued operations included ITISA results for the nine months ended September 30, 2008 and the same period in 2007. NRG classifies as discontinued operations the income from operations and gains/losses recognized on the sale of projects that were sold or have met the required criteria for such classification pending final disposition. For the nine months ended September 30, 2008 and the same period in 2007, NRG recorded income from discontinued operations, net of income tax expense, of $172 million and $13 million, respectively. NRG closed the sale of ITISA during the second quarter 2008.

Results of Operations Regional Discussions

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

Texas

For a discussion of the business profile of the Company s Texas operations, see pages 22-25 of NRG Energy, Inc. s 2007 Annual Report on Form 10-K.

Selected income statement data

	Three months ended September 30,			Nine months ended September 30,		
(In millions except otherwise noted)	**2008**	**2007**	**Change %**	**2008**	**2007**	**Change %**
Operating Revenues						
Energy revenue	$ 873	$ 803	9%	$ 2,344	$ 2,053	14%
Capacity revenue	129	90	43	366	273	34
Risk management activities	576	(4)	N/A	53	2	N/A
Contract amortization	69	59	17	215	167	29
Other revenues	14	8	75	83	31	168
Total operating revenues	1,661	956	74	3,061	2,526	21
Operating Costs and Expenses						
Cost of energy	366	358	2	1,037	905	15
Other operating expenses	154	175	(12)	468	527	(11)
Depreciation and amortization	108	113	(4)	334	341	(2)
Operating Income	$ 1,033	$ 310	233	$ 1,222	$ 753	62
MWh sold (in thousands)	13,111	13,792	(5)	36,817	37,037	(1)
MWh generated (in thousands)	12,891	13,420	(4)	36,147	36,157	
Business Metrics						
Average on-peak market power prices ($/MWh)	102.82	62.44	65	112.80	63.60	77
Cooling Degree Days, or CDDs (a)	1,417	1,458	(3)%	2,509	2,380	5
CDD s 30 year average	1,485	1,485		2,434	2,434	
Heating Degree Days, or HDDs (a)	6		N/A	1,163	1,280	(9)
HDD s 30 year average	5	5		1,221	1,208	1%

(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 $723 million for the three months ended September 30, 2008, compared to the same period in 2007, primarily due to:

Risk management activities an increase of $580 million was primarily due to $592 million in greater unrealized derivative gains offset by $12 million in lower realized gains on settled financial transactions. These changes reflect a reduction in forward power and gas prices at the end of the third quarter of 2008 compared to the end of the second quarter 2008. Gas and power prices in the comparable period of 2007 were relatively flat.

Energy revenues increased by $70 million due to higher merchant energy revenue as a result of increased power prices and sales volumes offset by lower contract energy revenue.

Operating Revenues

Total operating revenues increased by $705 million during the three months ended September 30, 2008, compared to the same period in 2007, due to:

Risk management activities gains of $576 million were recognized for the three months ended September 30, 2008 compared to a $4 million loss in the same period in 2007. The $576 million includes $573 million of unrealized mark-to-market gains and $3 million in settled gains, or financial revenue, compared to $19 million in unrealized derivative losses and $15 million of settled financial gains in the same period in 2007. The $573 million is the net effect of a $590 million gain from economic hedge positions and a $5 million loss on reversals of mark-to-market gains on economic hedges, partially offset by $12 million in unrealized mark-to-market losses on trading transactions. The $590 million gain from economic hedges incorporates $261 million in unrealized gains in the value of forward sales of electricity and fuel driven by lower power and natural gas prices. These hedges are considered effective economic hedges that do not receive cash flow hedge accounting treatment. The remaining $329 million in gains are from hedge ineffectiveness which was driven by decreasing gas prices while power prices decreased at a slower pace.

Energy revenues increased by $70 million due to:

o *Energy prices* increased by $101 million due to higher energy prices, reflecting a more favorable mix of merchant versus contract sales, as well as a 30% increase in merchant prices offset by a 14% decrease in contract energy prices. The increase in merchant prices was driven by higher average natural gas prices in ERCOT as compared to 2007.

o *Generation* decreased by $31 million due to lower generation volumes. A 1% increase in coal plant generation was offset by a 26% decrease in gas plant generation. Hurricane Ike in September 2008 caused major damage to the Houston area transmission grid which limited the Company s ability to deliver power that normally would be generated to serve demand in the region. The damage from hurricane Ike caused a lost opportunity to generate and deliver power reducing gas plant generation for the quarter.

Capacity revenue increased by $39 million due to a greater proportion of base-load contracts which contain a capacity component.

Contract amortization revenue increased by $10 million due to the volume of contracted energy affected by a greater spread between contract and market prices used in the Texas Genco purchase accounting.

Cost of Energy

Cost of energy increased by $8 million during the three months ended September 30, 2008, compared to the same period in 2007, due to:

Natural gas costs increased by $22 million due to a 45% rise in average natural gas prices offset by a 26% decrease in gas-fired generation.

Coal costs increased by $3 million due to an increase in coal prices.

Ancillary Service Costs increased by $11 million due to an increase in purchased ancillary services costs incurred to meet contract obligations and a rise in ancillary service costs charged by ERCOT.

These increases were partially offset by:

Nuclear fuel expense decreased by $15 million as amortization of nuclear fuel inventory established under Texas Genco purchase accounting ended in early 2008.

Amortized contract costs decreased by $11 million as amortization of water supply contracts established under Texas Genco purchase accounting ended in 2007.

Other Operating Expenses

Other operating expenses decreased by $21 million during the three months ended September 30, 2008, compared to the same period in 2007, due to:

Development costs decreased by $35 million primarily due to the initial costs for developing the nuclear units 3 and 4 at STP associated with the *Repowering*NRG initiative that began in 2007. Development costs for STP nuclear units 3 and 4 are being capitalized in 2008.

This decrease was offset by:

Operations & maintenance expense increased by $13 million which included increased maintenance activity at STP and increased diesel and chemical costs at the region s fossil plants. The increase in maintenance activity at STP was the result of equipment and refueling outages.

Yearly Results

Operating Income

Operating income increased by $469 million for the nine months ended September 30, 2008, compared to the same period in 2007, primarily due to:

Energy revenues increased by $291 million due to higher merchant energy revenue as a result of higher power prices and sales volumes offset by lower contract energy revenue.

Capacity revenue increased by $93 million due to a greater proportion of base-load contracts which contain a capacity component.

Risk management activities an increase of $51 million was primarily due to $128 million in greater unrealized derivative gains offset by $79 million in greater realized losses on settled financial transactions. These changes reflect a reduction in forward power and gas prices at the close of the nine months ended September 30, 2008. Gas and power prices in the comparable period 2007 were relatively flat.

These increases were offset by:

Cost of energy increased by $132 million reflecting the effects of increased natural gas and coal prices.

Operating Revenues

Total operating revenues increased by $535 million during the nine months ended September 30, 2008, compared to 2007, due to:

Risk management activities gains of $53 million were recognized for the nine months ended September 30, 2008 compared to a $2 million gain in the same period in 2007. The $53 million includes $100 million of unrealized mark-to-market gains and $47 million in settled losses, or financial revenue, compared to $29 million in unrealized derivative losses and $31 million of settled financial gains in the same period in 2007. The $100 million is the net effect of a $95 million gain from economic hedge positions and a $20 million loss on reversals of mark-to-market gains on economic hedges, partially offset by $25 million in unrealized mark-to-market gains on trading transactions. The $95 million gain from economic hedges incorporates $123 million in unrealized gains in the value of forward sales of electricity and fuel driven by higher power and natural gas prices. These hedges are considered effective economic hedges that do not receive cash flow hedge accounting treatment. The remaining $28 million in losses are from hedge ineffectiveness which was driven by increasing gas prices while power prices rose at a slower pace.

Energy revenues increased by $291 million due to:

- *Energy prices* increased by $292 million due to a more favorable mix of merchant versus contract sales resulting in a 38% increase in merchant prices offset by a 14% decrease in contract energy prices.

- o *Generation* remained largely unchanged at 36 million MWh. The mix of generation however did change with a 3% rise in nuclear generation at STP and a less than 1% rise in coal generation. This increase was offset by a 7% decrease in overall gas plant generation for the nine months ending September 2008. Hurricane Ike in September 2008 caused major damage to the Houston area transmission grid which limited the Company s ability to deliver power that normally would be generated to serve demand in the region. The damage from hurricane Ike caused a lost opportunity to generate and deliver power reducing gas plant generation.

Capacity revenue increased by $93 million due to a greater proportion of base-load contracts which contain a capacity component.

Other revenues increased by $52 million related to a $22 million increase in ancillary services revenue in 2008, a $22 million increase of allocations for trading of emission allowances and carbon financial instruments, and increased activity in trading natural gas and coal of $8 million.

Contract amortization revenue increased by $48 million due to the volume of contracted energy affected by a greater spread between contract prices and market prices used in the Texas Genco purchase accounting.

Cost of Energy

Cost of energy increased by $132 million during the nine months ended September 30, 2008, compared to the same period in 2007, due to:

Natural gas costs increased by $136 million due to a 40% rise in average gas prices offset by a 7% decrease in gas-fired generation.

Coal costs increased by $16 million due to the settlement of a coal contract dispute and higher coal prices.

Ancillary services increased by $19 million due to a $7 million increase in purchased ancillary services costs incurred to meet contract obligations and a $12 million rise in ancillary service costs incurred by ERCOT.

These increases were partially offset by:

Amortized contract costs decreased by $31 million as amortization of water supply contracts established under Texas Genco purchase accounting ended in 2007.

Nuclear fuel expense decreased by $11 million as amortization of nuclear fuel inventory established under Texas Genco purchase accounting ended in early 2008.

Purchased power decreased by $6 million due to lower outage rates at the region s baseload plants.

Other Operating Expenses

Other operating expenses decreased by $59 million during the nine months ended September 30, 2008, compared to 2007, due to:

Development costs decreased by $81 million primarily due to the initial costs for developing the nuclear units 3 and 4 at STP associated with the *Repowering*NRG initiative that began in 2007. Development costs for STP nuclear units 3 and 4 are being capitalized in 2008.

This decrease was primarily offset by:

Operations & maintenance expense increased by $20 million related to increased chemical and diesel costs at the region s fossil plants, STP equipment retirements and refueling outage, and the timing of annual outages at the WA Parish and Limestone plants.

Table of Contents

Northeast Region

For a discussion of the business profile of the Northeast region, see pages 25-28 of NRG Energy, Inc. s 2007 Annual Report on Form 10-K.

Selected income statement data

	Three months ended September 30,			Nine months ended September 30,		
(In millions except otherwise noted)	**2008**	**2007**	**Change %**	**2008**	**2007**	**Change %**
Operating Revenues						
Energy revenue	$ 324	$ 319	2%	$ 873	$ 845	3%
Capacity revenue	117	126	(7)	328	302	9
Risk management activities	223	28	N/A	39	23	70
Other revenues	13	29	(55)	62	69	(10)
Total operating revenues	677	502	35	1,302	1,239	5
Operating Costs and Expenses						
Cost of energy	198	199	(1)	557	506	10
Other operating expenses	89	92	(3)	273	298	(8)
Depreciation and amortization	26	25	4	77	74	4
Operating Income	$ 364	$ 186	96	$ 395	$ 361	9
MWh sold (in thousands)(b)	3,588	4,058	(12)	10,424	10,754	(3)
MWh generated (in thousands)	3,588	4,058	(12)	10,424	10,754	(3)
Business Metrics						
Average on-peak market power prices ($/MWh)	108.44	78.28	39	100.66	75.89	33
Cooling Degree Days, or CDDs(a)	446	511	(13)	611	672	(9)
CDD s 30 year average	430	430		534	534	
Heating Degree Days, or HDDs(a)	135	122	11%	3,866	4,116	(6)%
HDD s 30 year average	159	159		4,126	4,126	

(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.

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

Quarterly Results

Operating Income

Operating income increased by $178 million for the three months ended September 30, 2008, compared to the same period in 2007 due to:

Operating revenues increased by $175 million due to favorable impact of risk management activities, offset by lower capacity and other revenues.

Operating Revenues

Operating revenues increased by $175 million for the three months ended September 30, 2008, compared to the same period in 2007, due to:

Risk management activities gains of $223 million were recorded for the three months ending September 30, 2008, compared to gains of $28 million during the same period in 2007. The $223 million gain includes $201 million of unrealized mark-to-market gains and $22 million in gains on settled transactions, or financial revenue, compared to $15 million in unrealized mark-to-market gains and $13 million in financial revenue gains during the same period in 2007. The $201 million unrealized gain is the net effect of a $201 million gain from economic hedge positions, the reversal of $2 million of mark-to-market gains on economic hedges, the reversal of $6 million of mark-to-market gains on trading activity and $8 million in unrealized mark-to-market gains on trading activity. Gains are driven by decreases in power and gas prices.

Table of Contents

Energy revenues increased by $5 million due to:

- o *Energy prices* increased by $49 million reflecting an average 19% rise in merchant energy prices of $60 million. This increase was offset by lower net revenue of $11 million driven by higher net costs as a result of meeting obligations under load serving contracts in the PJM market.

- o *Generation* decreased by $44 million due to a net 12% decrease in generation in 2008 compared to 2007. The decrease in generation represents a 4% decline in coal generation, a 53% decrease in oil-fired generation and 26% lower gas-fired generation due to a cooler summer in 2008 compared to 2007.

Capacity revenues decreased by $9 million due to:

- o *NYISO* capacity revenues decreased by $9 million due to unfavorable prices. The lower capacity market prices are a result of NYISO s reductions in Installed Reserve Margins and ICAP in-city mitigation rules effective March 2008. These decreases were offset by higher capacity cash flow hedge revenue.

- o *PJM* capacity revenues decreased by $4 million due to lower capacity prices.

- o *NEPOOL* capacity revenues increased by $4 million due to higher capacity prices.

Other revenues decreased by $16 million due to $26 million lower net physical gas sales offset by $9 million from 2008 carbon financial instrument sales.

Cost of Energy

Cost of energy decreased by $1 million for the three months ended September 30, 2008, compared to the same period in 2007, due to:

Natural gas costs decreased by $15 million due to 26% lower generation offset by higher average prices per MMbtu.

Oil costs decreased by $2 million due to 53% lower oil-fired generation offset by higher oil prices.

These decreases were offset by:

Coal costs increased by $16 million due to higher coal costs and fuel transportation surcharges. This increase was offset by 4% lower coal generation.

Other Operating Expenses

Other operating expenses decreased by $3 million for the three months ended September 30 2008, compared to the same period in 2007, due to a $3 million property tax credit received in 2008 at the Arthur Kill plant.

Table of Contents

Yearly Results

Operating Income

Operating income increased by $34 million for the nine months ended September 30, 2008, compared to the same period in 2007 due to:

Operating revenues increased by $63 million due to higher energy revenue, capacity revenue and risk management revenues.

Other operating expenses decreased by $25 million consisting due to lower major maintenance expenses, property taxes and utilities.

These favorable variances were offset by:

Cost of energy increased by $51 million due to higher coal costs, increased coal transportation surcharges and higher natural gas prices. These were offset by lower oil costs from lower oil-fired generation due to a warmer summer and colder winter in 2007 compared to 2008.

Operating Revenues

Operating revenues increased by $63 million for the nine months ended September 30, 2008, compared to the same period in 2007, due to:

Energy revenues increased by $28 million due to:

- *Energy prices* increased by $102 million reflecting an average 12% rise in merchant energy prices. This was offset by lower contract revenue of $45 million driven by higher net costs incurred to service PJM contracts as a result of the increase in market energy prices.

- *Generation* decreased by $29 million due to a net 3% decrease in generation. The decrease in generation represents a 52% decrease in oil-fired generation and a 14% decrease in gas-fired generation. These results are due to a warmer summer and colder winter in 2007. This decrease was offset by a 4% increase in coal generation as a result of the timing of outages at the Huntley and Indian River plants and higher reliability at the Huntley plant.

Capacity revenues increased by $26 million due to:

- *PJM* capacity revenues increased by $21 million reflecting recognition of nine months of revenue from the RPM capacity market (effective on June 1, 2007) in 2008 compared to four months in 2007.

- *NEPOOL* capacity revenues increased $14 million consisting of $7 million from higher capacity prices and $7 million from increased revenue recognized on the Norwalk RMR contract (effective on June 19, 2007).

- *NYISO* capacity revenues decreased by $9 million due to unfavorable prices. The lower capacity market prices are a result of NYISO s reductions in Installed Reserve Margins and ICAP in-city mitigation rules effective March 2008. These decreases were offset by higher capacity cash flow hedge revenue.

Risk management activities gains of $39 million were recorded for the nine months ending September 30, 2008, compared to gains of $23 million during the same period in 2007. The $39 million gain includes $41 million of unrealized mark-to-market gains and $2 million of losses in settled transactions, or financial revenue, compared to $26 million in unrealized mark-to-market losses and $49 million in financial revenue gains during the same period in 2007. The $41 million unrealized gains is the net effect of a $58 million gain from economic hedge positions, the reversal of $11 million of mark-to-market gains on economic hedges, the reversal of $7 million of mark-to-market gains on trading activity and $1 million in unrealized mark-to-market gains on trading activity. Gains are driven by increases in power and gas prices.

Table of Contents

These gains were offset by:

Other revenues decreased by $7 million due to $21 million lower net physical gas sales in 2008 offset by $15 million from 2008 sales of carbon financial instruments.

Cost of Energy

Cost of energy increased by $51 million for the nine months ended September 30, 2008, compared to the same period in 2007, due to:

Coal costs increased by $54 million due to 4% higher coal generation, higher coal costs and fuel transportation surcharges.

Natural gas costs increased by $20 million, despite 14% lower generation, due to higher natural gas prices.

These increases were offset by:

Oil costs decreased by $23 million due to lower oil-fired generation as a result of a warmer summer and colder winter in 2007.

Other Operating Expenses

Other operating expenses decreased by $25 million for nine months ended September 30, 2008, compared to the same period in 2007, due to:

Major maintenance expenses decreased by $16 million due to less outage work at the Arthur Kill, Huntley and Norwalk plants.

Property taxes decreased by $7 million due to a $3 million property tax credit received in 2008 at the Arthur Kill plant, $3 million in credits against the property tax at the Western New York plants, and $1 million of property tax credits received in 2008 at the New York City plants.

Utilities decreased by $4 million due to a Connecticut station service settlement.

Table of Contents

South Central Region

For a discussion of the business profile of the South Central region, see pages 28-30 of NRG Energy, Inc. s 2007 Annual Report on Form 10-K.

Selected income statement data

	Three months ended September 30,			Nine months ended September 30,		
(In millions except otherwise noted)	**2008**	**2007**	**Change %**	**2008**	**2007**	**Change %**
Operating Revenues						
Energy revenue	$ 145	$ 126	15%	$ 375	$ 314	19%
Capacity revenue	59	56	5	174	163	7
Risk management activities	23	11	109	13	19	(32)
Contract amortization	7	7		18	18	
Other revenues	(1)		N/A	4		N/A
Total operating revenues	233	200	17	584	514	14
Operating Costs and Expenses						
Cost of energy	156	131	19	360	317	14
Other operating expenses	25	21	19	80	83	(4)
Depreciation and amortization	16	17	(6)	50	51	(2)
Operating Income	$ 36	$ 31	16	$ 94	$ 63	49
MWh sold (in thousands)	3,383	3,748	(10)	9,448	9,579	(1)
MWh generated (in thousands)	2,828	3,192	(11)	8,469	8,416	1
Business Metrics						
Average on-peak market power prices ($/MWh)	84.88	60.42	40	79.14	60.80	30
Cooling Degree Days, or CDDs(a)	1,027	1,249	(18)	1,577	1,853	(15)
CDD s 30 year average	997	997		1,487	1,487	
Heating Degree Days, or HDDs(a)	16	10	60%	2,239	2,080	8
HDD s 30 year average	33	33		2,246	2,226	1%

(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 $5 million for the three months ended September 30, 2008, compared to the same period in 2007, primarily due to:

Operating revenues increased by $33 million due to increases in energy revenue, capacity revenue and risk management activities. Mild weather in the summer months reduced demand from the region s cooperative customers, thereby allowing sales to the merchant market at higher prices. This increase was offset by the impacts of hurricane Gustav which caused major power outages in the region that limited demand from the cooperative customers during a period when the region would typically be purchasing power across the daily peaks. Hurricane Gustav also inflicted major damage to the transmission grid which limited the Company s ability to deliver power and restricted the output of the Big Cajun II coal plant.

Cost of energy increased by $25 million due to higher purchased energy and natural gas costs offset by lower coal generation costs.

Operating Revenues

Operating revenues increased by $33 million for the three months ended September 30, 2008, compared to the same period in 2007, due to:

Energy revenues increased by $19 million due to $23 million in higher merchant energy revenues, offset by a $3 million reduction in contract energy revenues. The growth in merchant energy revenues reflects a 40% rise in on-peak power prices combined with a 19% increase in merchant MWh sold. Hurricane Gustav resulted in major power outages throughout Louisiana and reduced load demand from the region s cooperative customers. Megawatt hour sales to cooperative customers fell by 6% in the third quarter of 2008 as compared to 2007.

Risk Management Activities gains of $23 million were recognized during the third quarter 2008 compared to gains of $11 million recognized during the same period in 2007. The $23 million gain includes $27 million in unrealized gains offset by realized losses of $4 million compared to $10 million in unrealized gains and $1 million in realized gains for the same period in 2007. The $27 million unrealized gain is the net effect of a $30 million unrealized mark-to-market gain from trading activity and the reversal of $3 million of mark-to-market gains on trading activity. Unrealized gains are primarily driven by decreases in power and gas prices.

Capacity revenues increased by $3 million due to increased capacity revenue from the PJM market.

Cost of Energy

Cost of energy increased by $25 million for the three months ended September 30, 2008, compared to the same period in 2007, due to:

Purchased energy increased by $14 million reflecting higher gas costs associated with the region s tolling agreements and market purchases.

Natural gas costs increased by $12 million as a result of the Bayou Cove and Big Cajun I Peaker plants running extensively to support transmission system stability after hurricane Gustav.

These increases were offset by:

Coal costs decreased by $1 million due to $6 million decline related to a 15% reduction in coal generation as a result of hurricane Gustav offset by a $5 million rise in coal unit costs as a result of increases in fuel transportation surcharges.

Other Operating Expenses

Other operating expenses increased by $4 million for the three months ended September 30, 2008, compared to the same period in 2007, due to:

G&A Expense $2 million higher corporate allocations in 2008 compared to the same period in 2007.

Operating and maintenance expense increase of $1 million due to higher labor expenses and higher major maintenance expenses.

Yearly Results

Operating Income

Operating income increased by $31 million for the nine months ended September 30, 2008, compared to the same period in 2007, due to:

Operating revenues increased by $70 million due to the increase in energy revenue and capacity revenue offset by an unfavorable impact of risk management activities.

Cost of energy increased by $43 million due to higher purchased energy, natural gas coal transportation costs, and transmission costs.

Operating Revenues

Operating revenues increased by $70 million for the nine months ended September 30, 2008, compared to the same period in 2007, due to:

Energy revenues increased by $61 million due to $57 million in higher merchant energy revenues and $4 million of improved contract energy revenues. The growth in merchant energy revenues reflects a 1% rise in total MWh generated combined with a 6% decrease in contract load MWh thereby allowing for more sales to the merchant market at higher prices. The increase in revenue from contract load is driven by higher fuel cost pass-through adjustments for the region s cooperative customers, while mild weather and the impacts of hurricane Gustav lowered load requirements. Megawatt hour sales to contract customers decreased 6% in 2008 as compared to 2007. Merchant energy MWh sold increased by 35%.

Capacity revenues increased by $11 million due to new peak loads set by the region s cooperative customers which resulted in $6 million of additional capacity payments and increased RPM capacity payments of $5 million from the PJM market.

These increases were offset by:

Risk Management Activities gains of $13 million were recognized during the first nine months of 2008 compared to $19 million in gains recognized during the same period in 2007. Unrealized gains in 2008 of $17 million offset by realized losses of $4 million compared to $14 million of unrealized gains and $5 million of realized gains in 2007. The $17 million unrealized gain is the net effect of a $31 million unrealized mark-to-market gain from trading activities in the region offset by the reversal of $14 million of mark-to-market gains on trading activity. Unrealized gains are primarily driven by decreases in power and gas prices.

Cost of Energy

Cost of energy increased by $43 million for the nine months ended September 30, 2008, compared to the same period in 2007, due to:

Purchased energy increased by $18 million reflecting a 28% increase in the average cost per MWh of purchased energy which reflects higher gas costs associated with the region s tolling agreements. This increase was offset by a decrease in purchased MWh as increased plant availability reduced power purchases required to support contract load.

Natural gas costs increased $12 million. The region s Bayou Cove and Big Cajun I Peaker plants ran extensively to support transmission system stability after hurricane Gustav in September 2008.

Coal costs increased by $7 million due to a $2 per ton increase in fuel transportation surcharges. These increases were offset by a 1% drop in coal generation and a $3 million decrease in allocated rail car lease fees among the regions. This allocation of the railcar lease better reflects the actual usage of the Company s railcar fleet.

Transmission costs increased by $6 million due to additional point-to-point transmission costs driven by an increase in merchant energy sales.

Other Operating Expenses

Other operating expenses decreased by $3 million for the nine months ended September 30, 2008, compared to the same period in 2007, due to:

G&A Expense Franchise tax decreased by $7 million due to a retroactive charge recorded in the first quarter 2007. The Louisiana state franchise tax is assessed on the Company s total debt and equity that significantly increased following the Acquisition of Texas Genco LLC. This decrease was offset by $5 million in higher corporate allocations in 2008 compared to the same period in 2007.

Operating and maintenance expense Major maintenance decreased by $5 million due to more extensive spring outage work performed at the Big Cajun II plant in 2007 compared to the same period in 2008. Normal maintenance rose $2 million as a result of increased forced outages and higher contractor costs.

Table of Contents

West Region

For a discussion of the business profile of the West region, see pages 30-32 of NRG Energy, Inc. s 2007 Annual Report on Form 10-K.

Selected income statement data

	Three months ended September 30,			Nine months ended September 30,		
(In millions except otherwise noted)	**2008**	**2007**	**Change %**	**2008**	**2007**	**Change %**
Operating Revenues						
Energy revenue	$ 12	$ 1	N/A	$ 25	$ 2	N/A
Capacity revenue	28	32	(13)%	97	87	11%
Risk management activities						
Other revenues				5	1	400
Total operating revenues	40	33	21	127	90	41
Operating Costs and Expenses						
Cost of energy	11	1	N/A	25	2	N/A
Other operating expenses	14	19	(26)	52	58	(10)
Depreciation and amortization	2	1	100	6	2	200
Operating Income	$ 13	$ 12	8	$ 44	$ 28	57
MWh sold (in thousands)	124	4	N/A	213	5	N/A
MWh generated (in thousands)	124	4	N/A	213	5	N/A
Business Metrics						
Average on-peak market power prices ($/MWh)	96.72	68.87	40	91.52	65.93	39
Cooling Degree Days, or CDDs(a)	687	634	8	893	770	16
CDD s 30 year average	506	506		663	663	
Heating Degree Days, or HDDs(a)	61	91	(33)%	2,157	1,917	13
HDD s 30 year average	108	108		2,098	2,081	1%

(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 $1 million for the three months ended September 30, 2008, compared to the same period in 2007, due to:

Energy revenues increased by $11 million due to the dispatch of the El Segundo plant outside of the tolling agreement in 2008. In 2007, no such dispatch occurred.

Other Operating Expenses decreased by $5 million due to a reduction in *Repowering*NRG permitting expenses for the El Segundo and Carlsbad Energy Centers for 2008 as compared to 2007.

These increases were partially offset by:

Cost of energy increased by $10 million due to the 2008 dispatch of the El Segundo plant.

Capacity revenues decreased by $4 million primarily due to expiration of a two year tolling agreement at the El Segundo facility partially offset by the tolling agreement at the Long Beach plant:

o *El Segundo* The expiration of the two year tolling agreement at the end of April resulted in a decrease of $5 million in capacity revenues for the three months ended September 30, 2008.

o *Long Beach* On August 1, 2007, NRG successfully completed the repowering of a 260 MW natural gas-fueled generating plant at its Long Beach generating facility. The plant contributed $1 million in incremental capacity revenues for the three months ended September 30, 2008.

Table of Contents

Yearly Results

Operating Income

Operating income increased by $16 million for the nine months ended September 30, 2008, compared to the same period in 2007, due to:

Capacity revenues increased by $10 million primarily due to the tolling agreement at the Long Beach plant partially offset by the expiration of a two year tolling agreement at the El Segundo facility:

- *Long Beach* On August 1, 2007, NRG successfully completed the repowering of a 260 MW natural gas-fueled generating plant at its Long Beach generating facility. The plant contributed $15 million in incremental capacity revenues for the nine months ended September 30, 2008.
- *El Segundo* The expiration of the two year tolling agreement at the end of April resulted in a decrease of $5 million in capacity revenues for the nine months ended September 30, 2008

Energy revenues increased by $23 million due to the 2008 dispatch of the El Segundo plant outside of the tolling agreement in 2008. In 2007, no such dispatch occurred.

Other revenues increased by $4 million due to increased trading activity of emission allowances in 2008.

Other operating expense decreased by $6 million due to a reduction *Repowering*NRG permitting expenses of $4 million for the El Segundo and Carlsbad Energy Centers in 2008 as compared to 2007. In addition an environmental liability of $2 million was recognized in 2007 related to the El Segundo plant.

These increases were partially offset by:

Cost of energy increased by $23 million due to the dispatch of the El Segundo plant outside of the tolling agreement in 2008. In 2007, no such dispatch occurred.

Depreciation and amortization increased by $4 million, reflecting the depreciation associated with the successful completion of the *Repowering*NRG project at the Long Beach plant.

Liquidity and Capital Resources

Liquidity Position

As of September 30, 2008 and December 31, 2007, NRG s liquidity was approximately $3.0 billion and $2.7 billion, respectively, and comprised of the following:

(In millions) As of	September 30, 2008	December 31, 2007
Cash and cash equivalents	$ 1,483	$ 1,132
Restricted cash	32	29
Total cash	1,515	1,161
Synthetic letter of credit availability	534	557
Revolver credit facility availability	1,000	997
Total liquidity	$ 3,049	$ 2,715

For the nine months ended September 30, 2008, total liquidity increased by $334 million due to higher cash balances of $354 million. Changes in cash balances are further discussed hereinafter under *Cash Flow Discussion*. Cash and cash equivalents at September 30, 2008 are predominantly held in money market funds invested in treasury securities or treasury repurchase agreements.

Management believes that the Company s liquidity position and cash flows from operations will be adequate to finance operating and maintenance capital expenditures, to fund dividends to NRG s preferred shareholders, 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%.

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, asset sales, existing cash on hand and cash flows from operations.

Financing Arrangements

First and Second Lien Structure

NRG has granted first and second liens to certain counterparties on substantially all of the Company s assets in the United States in order to secure primarily long-term obligations under power and gas sale agreements and related contracts. NRG uses the first or 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-the-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 is limited by volumes hedged, not by the value of underlying out-of-the money positions. The first lien program does not require us 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 rolling 60 months with such permitted hedging volumes 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.

As part of the amendments to NRG s Senior Credit Facility entered into on June 8, 2007, the Company obtained the ability to move its second lien counterparty exposure to the first lien on a *pari passu* basis with the Company s existing first lien lenders. In exchange for moving to a *pari passu* basis with the Company s first lien lenders, the counterparties agreed to relinquish letters of credit issued by NRG which they held as a part of their collateral package.

The Company s lien counterparties may have a claim on our assets to the extent their net positions are out-of-the-money. As of September 30, 2008 and October 23, 2008, the first lien exposure of net out-of-the-money positions to counterparties on hedges was $405 million and $185 million, respectively. As of September 30, 2008 and October 23, 2008, the second lien net out-of-the-money positions to counterparties on hedges was approximately $16 million and $2 million, respectively.

Table of Contents

The following table summarizes the amount of MWs hedged against the Company s baseload assets and as a percentage relative to the Company s forecasted baseload capacity under the first and second lien structure as of October 23, 2008:

Equivalent Net Sales secured by First and Second Lien Structure (a)	**2008(b)**	**2009**	**2010**	**2011**	**2012**	**2013**
In MW	5,751	44,529	40,515	33,341	19,499	7,650
As a percentage of total forecasted baseload capacity (c)	56%	73%	68%	56%	33%	14%

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

(b) 2008 MW value consists of November through December positions only.

(c) Forecasted baseload capacity under the first and second lien structure represents 80% of the total Company s baseload assets.

Common Stock Finance I Debt

The Company s Senior Credit Facility and Senior Notes indentures contain restricted payment provisions limiting the use of funds for transactions such as common share repurchases. To maintain restricted payment capacity under the Senior Notes indentures, in March 2008 the Company executed an arrangement with CS to extend the notes and preferred interest maturities of CSF I from October 2008 to June 2010. In addition, the settlement date of an embedded derivative, or CSFI CAGR, which is based on NRG s share price appreciation beyond a 20% compound annual growth rate since the original date of purchase by CSF I, was extended 30 days to early December 2008. As part of this extension arrangement, the Company contributed 795,503 treasury shares to CSF I as additional collateral to maintain a blended interest rate in the CSF I facility of approximately 7.5%. Accordingly, the amount due at maturity in June 2010 for the CSF I notes and preferred interests will be $248 million. In August 2008, the Company amended the CSF I notes and preferred interests to early settle the CSFI CAGR. Accordingly, NRG made a cash payment of $45 million to CS for the benefit of CSF I, which was recorded to interest expense in the Company s Consolidated Statement of Operations.

ITISA

On April 28, 2008, NRG completed the sale of its 100% interest in Tosli Acquisition B.V., or Tosli, which held all NRG s interest in ITISA, to Brookfield Renewable Power Inc. (previously Brookfield Power Inc.), a wholly-owned subsidiary of Brookfield Asset Management Inc. In addition, the purchase price adjustment contingency under the sale agreement was resolved on August 7, 2008. In connection with the sale, NRG received $300 million of cash proceeds from Brookfield, and removed $163 million of assets, including $59 million of cash, $122 million of liabilities, including $63 million of debt, and $15 million in foreign currency translation adjustment from its 2008 condensed consolidated balance sheet As discussed in Note 3, *Discontinued Operations*, the activities of Tosli and ITISA have been classified as discontinued operations.

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 September 30, 2008, commercial operations had total cash collateral outstanding of $390 million, and $464 million outstanding in letters of credit to third parties primarily to support its hedging activities.

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 general perception of its creditworthiness.

Table of Contents

Debt Service Obligations

Beginning in 2008, 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 B loan. 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. The mandatory annual offer required for 2008 was $446 million, against which the Company made a $300 million prepayment in December 2007. Of the remaining $146 million, the lenders accepted a repayment of $143 million in March 2008. The amount retained by the Company can be used for investments, capital expenditures and other items as defined by the Senior Credit Facility.

Capital Expenditures and RepoweringNRG Equity Investments in Affiliates

For the nine months ended September 30, 2008, the Company s capital expenditures, including accruals, were approximately $709 million, of which $466 million was related to *Repowering*NRG projects. The following table summarizes the Company s capital expenditures for the nine months ended September 30, 2008 and the estimated capital expenditure and repowering investments forecast for the remainder of 2008.

(In millions)	**Maintenance**	**Environmental**	**RepoweringNRG**	**Total**
Northeast	$ 15	$ 93	$ 19	$ 127
Texas	94	17	82	193
South Central	7	5		12
West	2		28	30
NINA			55	55
Wind			282	282
Other	10			10
Capital expenditures through September 30, 2008	128	115	466	709
Capital expenditures through the remainder of 2008	80	87	97	264
Total estimated capital expenditures for 2008	$ 208	$ 202	$ 563	$ 973
Total estimated repowering equity investments for 2008	N/A	N/A	$ 87	$ 87

*Repowering*NRG *capital expenditures and investments* *Repowering*NRG project capital expenditures consisted of approximately $170 million for wind turbines and construction related costs for the Elbow Creek wind farm project which is currently under construction and $112 million in turbine purchases for other wind projects currently under development. In addition, the Company s *Repowering*NRG capital expenditures included $82 million related to the construction of Cedar Bayou Unit 4 in Texas, $55 million related to the development of STP Units 3 and 4 in Texas,

$28 million for the repowering of the El Segundo generating station in California, and $19 million for the construction of Cos Cob in Connecticut.

The Company s estimated repowering capital expenditures for the remainder of 2008 are expected to consist of approximately $57 million related to the construction and equipment procurement for the Elbow Creek wind farm project and other wind projects under development. In addition, the Company expects to incur additional 2008 capital expenditures of approximately $13 million towards the construction of Cedar Bayou Unit 4 and $19 million towards the development of STP Units 3 and 4.

Related to *Repowering*NRG, the Company expects to contribute equity of approximately $87 million to its Sherbino wind farm project in 2008 and has posted a letter of credit in that amount. For the nine months ended September 30, 2008, the Company invested $17 million in Sherbino.

Major maintenance and environmental capital expenditures The Company s baghouse project at its Huntley and Dunkirk plants resulted in environmental capital expenditures of $70 million for the nine months ended September 30, 2008. Other capital expenditures included $31 million for STP fuel and $63 million in maintenance capital expenditures in Texas primarily related to the W.A. Parish and Limestone plants.

NRG anticipates funding these maintenance capital projects primarily with funds generated from operating activities. The Company is also pursuing funding for certain environmental expenditures in the Northeast region through Solid Waste Disposal Bonds utilizing tax exempt financing, and expects to draw upon such funds during 2009.

Table of Contents

Loans to affiliates During the first nine months of 2008, the Company loaned $15 million in funds to GenConn Energy LLC, or GenConn, a 50/50 joint venture vehicle of NRG and The United Illuminating Company as a part of the Devon plant project. On October 16, 2008, the Company loaned a further $15 million in funds to GenConn as a part of the Devon and Middletown plant projects. These loans, which are in the form of an interest bearing note, mature in 2009, at which point GenConn s construction costs are expected to be funded through equity of NRG and The United Illuminating Company and non-recourse project level financing.

Environmental Capital Expenditures

Based on current rules, technology and plans, NRG has estimated that environmental capital expenditures to be incurred from 2008 through 2013 to meet NRG s environmental commitments will be approximately $1.3 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.

The following table summarizes the major environmental capital expenditures for the referenced periods by region:

(In millions)	Texas	Northeast	South Central	Total
2008	$ 24	$ 172	$ 6	$ 202
2009		256		256
2010	7	187	52	246
2011	17	154	102	273
2012	27	67	100	194
2013	32		67	99
Total	$ 107	$ 836	$ 327	$ 1,270

2008 Capital Allocation Plan

In December 2007, the Company initiated its 2008 Capital Allocation Program, with the repurchase of 2,037,700 shares of NRG common stock during that month for approximately $85 million. In February 2008, the Company s Board of Directors authorized an additional $200 million in common share repurchases that would raise the total 2008 Capital Allocation Program to approximately $300 million. In the first quarter 2008, the Company repurchased 1,281,600 shares of NRG common stock for approximately $55 million. In the third quarter 2008, the Company repurchased an additional 3,410,283 of NRG common stock in the open market for approximately $130 million. As of September 30, 2008, NRG had repurchased a total of 6,729,583 shares of NRG common stock at a cost of approximately $270 million as part of its 2008 Capital Allocation Program.

2009 Capital Allocation Plan

On October 30, 2008, the Company announced its 2009 Capital Allocation Plan to purchase an additional $300 million in common stock. As part of the 2009 plan, the Company will invest over $511 million in maintenance and environmental capital expenditures in the existing assets in 2009 and $118 million in projects under

*Repowering*NRG that are currently under construction or for which there exist current obligations. Finally, in addition to a scheduled debt amortization payment, in the first quarter 2009 the Company will offer its first lien lenders 50% of its 2008 excess cash flow (as defined in the Senior Credit Facility).

Benefit Plans Obligations

Based on the Company s December 31, 2007 measurement of its benefit obligation for its three defined benefit pension plans, the Company is expected to contribute $13 million to these plans from October 1, 2008 through March 31, 2009. Based on weak market performance of plan assets, the plans would require an additional contribution of approximately $60 million from the Company in 2009.

Table of Contents

Cash Flow Discussion

The following table reflects the changes in cash flows for the comparative periods. All cash flow categories include the cash flows from both continuing operations and discontinued operations:

(In millions) Nine months ended September 30,	2008	2007
Net cash provided by operating activities	$ 1,041	$ 976
Net cash used by investing activities	$ (332)	$ (232)
Net cash used by financing activities	$ (401)	$ (375)

Net Cash Provided By Operating Activities

For the nine months ended September 30, 2008, net cash provided by operating activities increased by $65 million compared to the same period in 2007. The difference was due to:

Increase in generation and energy prices An increase in power generation and higher energy prices contributed to $278 million more in cash from operations after adjusting net income for the effect of non-cash items for the first nine months of 2008 compared to 2007.

Collateral deposits During the first nine months of 2008, an increase in net collateral deposits of $320 million to support the Company s hedging and trading activities reduced cash from operations by $213 million compared to the same period in 2007.

Net Cash Used By Investing Activities

For the nine months ended September 30, 2008, net cash used in investing activities was approximately $100 million more than the same period in 2007. This was due to:

Capital expenditures NRG s capital expenditures increased by $340 million due to *Repowering*NRG projects, primarily related to $282 million for wind turbines related to Elbow Creek and other wind projects currently under development.

Sale of discontinued operations Net proceeds from the sale of ITISA were $241 million in 2008.

Asset sales The Company received $14 million in proceeds primarily from the sale of rail cars in the first nine months of 2008 compared to proceeds of $57 million for the sale of Red Bluff and Chowchilla II power plants and equipment in the same period in 2007 for a net decrease in cash of $43 million.

Trading of emission allowances Net purchases and sales of emission allowances resulted in an increase in cash of $51 million for the first nine months of 2008 compared to 2007.

Equity Contribution The Company contributed approximately $17 million to its equity investment in Sherbino.

Net Cash Used By Financing Activities

For the nine months ended September 30, 2008, net cash used by financing activities increased by approximately $26 million compared to 2007, due to:

Term B loan debt payment In 2008, the Company paid down $166 million of its Term B loan, including the payment of excess cash flow, as discussed above under *Debt Service Obligations*. The Company paid down $25 million of its Term B loan during the first nine months of 2007 for a net cash decrease of $141 million for the nine months ended of 2008 compared to the same period in 2007.

Share repurchase During the first nine months of 2008, the Company repurchased approximately $185 million shares of NRG common stock, compared to $268 million for 2007 for a net $83 million increase to cash for the nine months 2008 compared to the same period in 2007.

Sale of minority interest The Company received $50 million in proceeds from the sale of minority interest in NINA in the first half of 2008.

Payment of financing element of acquired derivatives For the nine months of 2008, the Company paid approximately $49 million related to the settlement of gas swaps related to the acquisition of Texas Genco in 2006.

Issuance of debt During the first nine months of 2008, the Company received $20 million in proceeds from the borrowings made by its subsidiaries.

Exercise of stock options The Company received proceeds of $8 million from the exercise of stock options for the nine months ended 2008.

NOL s, Deferred Tax Assets and FIN 48 Implications

As of September 30, 2008, the Company had generated a total domestic continuing pre-tax book income of $1,249 million and foreign continuing pre-tax book income of $75 million. In addition, NRG has cumulative foreign NOL carryforwards of $253 million, of which $54 million will expire starting in 2011 through 2017 and $199 million that do not have an expiration date.

In addition to these amounts, the Company has $709 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 statements 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, we anticipate income tax payments of up to $100 million in 2008. Beginning in 2009, income tax payments will be approximately 30% of pre-tax book income.

However, as the position remains uncertain, of the $709 million of tax effected unrecognized tax benefits, the Company has recorded a non-current tax liability of $138 million and may accrue the remaining balance as an increase to non-current liabilities until final resolution with the related taxing authority. The $138 million non-current tax liability for unrecognized tax benefits is due to taxable earnings for the period for which there are no NOLs available to offset for financial statement purposes.

The Company has been contacted for examination by the Internal Revenue Service for years 2004 through 2006. The audit commenced during the third quarter 2008 and is expected to continue for approximately 18 to 24 months.

New and On-going Company Initiatives

Nuclear Innovation North America

In March 2008, NRG formed Nuclear Innovation North America LLC, or NINA, an NRG subsidiary 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 that NRG is developing on a 50/50 basis with City of San Antonio s agent CPS Energy at the STP nuclear power station site. NRG s rights to develop STP units 3 and 4 have been contributed to special purpose subsidiaries of NINA. NINA will focus only on the development of new projects and will not be involved in the operations of the existing STP units 1 and 2.

In April 2008, NINA entered into a $20 million revolving loan arrangement, as borrower, to provide working capital to NINA. This facility matures on April 21, 2011, and permits NINA to make cash draws or issue letters of credit. Borrowings accrue interest at either LIBOR or a base rate, plus a spread. As of September 30, 2008, NINA has

$9.5 million outstanding under this facility.

Toshiba Corporation, or Toshiba, will serve as the prime contractor on all of NINA s projects, and has agreed to partner with NRG on the NINA venture. Toshiba is currently prime contractor of the STP units 3 and 4 project and is providing licensing support and leading all engineering and scheduling activities, which ultimately will lead to responsibility for constructing the project. Toshiba will invest $300 million in NINA in six annual installments of $50 million, the last three of which are subject to certain conditions, in exchange for a 12% equity ownership in NINA. Half of this investment will be to fund development activities related to STP units 3 and 4. The other half will be targeted towards developing and deploying additional Advanced Boiling Water Reactor, or ABWR, projects in North America with other potential partners. Toshiba is also extending pre-negotiated Engineering, Procurement and Construction, or EPC, terms to NINA for two additional two-unit nuclear projects similar to the terms being offered for the STP unit 3 and 4 development.

Table of Contents

NINA intends to use the NRC certified ABWR design, with only a limited number of changes to enhance safety and construction schedules. On September 24, 2008, NINA filed a revision to the COLA. Given the changes to the application, NRG anticipates STP units 3 and 4 will come online in 2015 and 2016, respectively.

RepoweringNRG Update

Cos Cob Generating Station

On June 26, 2008, NRG announced the completion of the repowering of its Cos Cob generating station in Fairfield County, Connecticut which added 40 MW of power to the site. The Company funded and developed this project which added two new gas turbine units, between the existing three units, bringing total output to 100 MW. All five units were retrofitted to use water injection technology, resulting in a 50% net station reduction in NO_x and a 97% reduction in SO_2 emissions by using low-sulfur distillate fuel.

Sherbino I Wind Farm

On October 22, 2008, NRG and its 50/50 joint venture partner, BP Wind Energy North America Inc., or BP, announced the completion of its Sherbino I Wind Farm project in Pecos County, Texas. The wind farm was developed by NRG s subsidiary Padoma Wind Power LLC, or Padoma. Padoma managed the construction and development, which began in late 2007, and BP will operate and dispatch the facility. Sherbino is a 150 MW wind farm consisting of 50 Vestas wind turbine generators, each capable of generating up to 3 MW of power. Since NRG has a 50 percent ownership, Sherbino will provide the Company a net capacity of 75 MW.

GenConn Energy LLC

On March 3, 2008, GenConn Energy LLC, or GenConn, a 50/50 joint venture vehicle of NRG and The United Illuminating Company, submitted a binding bid to the Connecticut Department of Public Utility Control, or DPUC, for new peaking generation facilities in Connecticut subject to a regulated long-term contract. The DPUC subsequently made two awards to GenConn. The first, on June 25, 2008, was for the construction and operation of approximately 200 MW of peaking generation at NRG s Devon plant in Milford, Connecticut with a commercial operation date of June 1, 2010 and a 30-year term. The second, on October 6, 2008, was for the construction and operation of approximately 200 MW of peaking generation at NRG s Middletown facility in Middletown, Connecticut with a commercial operation date of June 1, 2011 and a 30-year term. GenConn subsidiaries have executed contracts for differences with Connecticut Light & Power for each of these projects that have been approved by the DPUC.

El Segundo Energy Center LLC

On March 7, 2008, NRG, through its wholly-owned subsidiary, El Segundo Energy Center LLC, or ESEC, executed a 10-year tolling agreement, or PPA, with Southern California Edison, or SCE. Pre-construction activities started shortly thereafter on a 550 MW rapid response combined cycle facility in El Segundo, California. Since that time, NRG has made non-refundable payments of approximately $17 million to the equipment provider to meet the project construction schedule.

On July 29, 2008, the Los Angeles County Superior Court issued a ruling in *Natural Resource Defense Council, Inc. v. South Coast Air Management District* (Case No. BS 110792), or NRDC I, that eliminated the availability of certain air credits from the Priority Reserve program of the South Coast Air Management District, or SCAQMD. On August 18, 2008, the Natural Resource Defense Council, or NRDC, filed a Complaint for Declaratory and Injunctive Relief in the US District Court for the Central District of California (*Natural Resource Defense Council, Inc. v. South Coast Air Management District* (Case No. CV08-05403), or NRCD II, claiming the emission reduction credits created by retiring power generation units and those created by SCAQMD Rule 1309.1 do not meet federal Clean Air Act requirements.

If successful, these actions may affect ESEC s ability to use air emission credits generated by retiring generating units and the distribution of credits from offset accounts. Although the California Public Utilities Commission, or CPUC, approved the PPA on September 18, 2008, the project is unlikely to reach commercial operation by June 1, 2011 as a result of the NRDC I and II related permitting delays.

Plants under Construction

The Company has two projects under construction, the Cedar Bayou Generating Station and the Elbow Creek Wind Farm.

In August 2007, NRG, through its wholly owned subsidiary, NRG Cedar Bayou Development Company LLC, entered into a definitive agreement with EnergyCo Cedar Bayou 4, LLC to jointly develop, construct, operate and own, on a 50/50 undivided interest basis, a 550 MW combined cycle natural gas turbine generating plant at NRG s Cedar Bayou Generating Station in Chambers County, Texas. This project is expected to reach commercial operations in mid-2009.

On March 27, 2008, NRG, through Padoma, began construction of the Elbow Creek project, a wholly-owned 122 MW wind farm in Howard County near Big Spring, Texas. This project is scheduled to reach commercial operations by the end of 2008.

Huntley IGCC

In December 2006, in a competitive bid process with New York Power Authority, or NYPA, NRG won a conditional award of a power purchase agreement in support of the construction of a 600 MW IGCC plant at its existing Huntley facility. The project was cancelled on July 22, 2008.

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.

Retained or Contingent Interests

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

Derivative Instrument Obligations

On August 11, 2005, NRG issued 3.625% Preferred Stock that included a conversion feature which is considered a derivative per FAS 133, as amended. Although it is considered a derivative, it is exempt from derivative accounting as it is excluded from the scope pursuant to paragraph 11(a) of FAS 133. As of September 30, 2008, based on the Company s stock price, the redemption value of this embedded derivative was approximately $2 million.

On October 13, 2006, NRG, through its unrestricted wholly-owned subsidiaries, NRG Common Stock Fund I, or CSF I, and NRG Common Stock Fund II, or CSF II, issued notes and preferred interests for the repurchase of NRG s common stock. Included in each agreement was features considered an embedded derivative per SFAS 133. Although it is considered a derivative, it is exempt from derivative accounting as it is excluded from the scope pursuant to paragraph 11(a) of SFAS 133. In August 2008, the Company amended the CSF I notes and preferred interests to early settle the CSF I embedded derivative. Accordingly, NRG made a cash payment of $45 million to CS for the benefit of CSF I, which was recorded to interest expense in the Company s Consolidated Statement of Operations. As of September 30, 2008, based on the Company s stock price, the redemption value on the CSF II embedded derivative was approximately $22 million.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable interest in equity investments As of September 30, 2008, NRG had not entered into any financing structure that was designed to be off-balance sheet that would create incremental liquidity, financing or market risk or credit risk to the Company. However, 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. NRG s pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $193 million as of September 30, 2008. This indebtedness may restrict the ability of these affiliates to issue dividends or distributions to NRG.

Table of Contents

In addition, as previously discussed, NRG and BP entered into a 50/50 joint venture in February 2008 to build and own Sherbino. NRG expects to contribute $87 million in equity to the joint venture and has posted a letter of credit in this amount. NRG s maximum exposure to loss is limited to its expected equity investments.

Synthetic Letter of Credit Facility and Revolver Facility Under NRG s amended Senior Credit Facility which the Company entered into in June 2007, the Company has a $1.3 billion Synthetic Letter of Credit Facility which is secured by a $1.3 billion cash deposit at Deutsche Bank AG, New York Branch, the Issuing Bank. This deposit was funded using proceeds from the Senior Credit Facility investors who participated in the facility syndication. Under the Synthetic Letter of Credit Facility, NRG is allowed to issue letters of credit for general corporate purposes including posting collateral to support the Company s commercial operations activities. Currently NRG has the capability to issue under its Revolving Credit Facility unfunded Letters of Credit up to $900 million for ongoing working capital requirements and for general corporate purposes, including acquisitions that are permitted under the Senior Credit Facility. In addition, NRG is permitted to issue additional letters of credit of up $100 million under the Senior Credit Facility through other financial institutions.

As of September 30, 2008, the Company had issued $766 million in letters of credit under the Synthetic Letter of Credit Facility. The Company had no letters of credit issued under the Revolving Credit Facility as of September 30, 2008. A portion of these letters of credit supports non-commercial letter of credit obligations.

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 Form 10-K. Also see Note 14, *Commitments and Contingencies*, to the condensed consolidated financial statements of this Form 10-Q for a discussion of new commitments and contingencies that also include contractual obligations and commercial commitments that occurred during the third quarter 2008.

Critical Accounting 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 of America. The preparation of these financial statements and related disclosures in compliance with generally accepted accounting principles, or US 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, 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 also may 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.

Table of Contents

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 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, volatility in commodities, and correlations between various commodities, such as natural gas, electricity, coal and oil. 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.

As part of NRG s overall portfolio, NRG manages the commodity price risk of the Company s merchant generation operations by entering into various derivative or non-derivative instruments to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel. These instruments include forward purchase and sale contracts, futures and option contracts traded on the New York Mercantile Exchange, and swaps and options traded in the over-the-counter financial markets. The portion of forecasted transactions hedged may vary based upon management s assessment of market, weather, operation 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 commodity and derivative contracts held and sold. These estimates consider various factors, including closing exchange and over-the-counter price quotations, time value, volatility factors and credit exposure. 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 market risk of the Company s portfolio to commodity prices using 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. NRG s total portfolio includes mark-to-market and non-mark-to-market energy assets and liabilities.

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 September 30, 2008, 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:

(In millions) VAR (a)	2008	2007
Three months ended September 30:	$ 51	$ 32
Average	48	31
Maximum	62	37
Minimum	35	24
Nine months ended September 30:	$ 51	$ 32
Average	50	26
Maximum	65	37
Minimum	35	15

(a) Prior to December 4, 2007, NRG s VAR measurement was based on a rolling 24-month forward looking period.

Due to the inherent limitations of statistical measures such as VAR, the relative immaturity 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 September 30, 2008, for the entire term of these instruments entered into for both asset management and trading was approximately $16 million.

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.

As of September 30, 2008, the Company had various interest rate swap agreements with notional amounts totaling approximately $2.6 billion. If the swaps had been discontinued on September 30, 2008, the Company would have owed the counterparties approximately $74 million. Based on a diverse group of counterparties, NRG believes its exposure to credit risk due to nonperformance by counterparties to its hedge contracts to be insignificant. In addition, due to the fact that the interest rate environment at that time was lower than the interest rates in NRG s interest rate swaps, NRG could then engage in new interest rate swaps at improved rates in the event of default by its counterparties.

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 September 30, 2008, a 100 basis point change in interest rates would result in a $13 million change in interest expense on a rolling twelve month basis.

As of September 30, 2008, the Company s long-term debt fair value was $7.2 billion and the carrying amount was $8.0 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 $420 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.

Based on a sensitivity analysis, a $1 per MMBtu increase or decrease in natural gas prices across the term of the marginable contracts would cause a change in margin collateral outstanding of approximately $69 million as of September 30, 2008. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of September 30, 2008.

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. The Company monitors and manages 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 risk with a diversified portfolio of counterparties, including ten participants under its first and second lien structure. 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.

A sharp economic downturn in the US and overseas markets during the latter part of 2008 was prompted by a combination of factors: tight credit markets, speculation and fear over the health of the US and global financial systems, and weaker economic activity in general prompting fears of an economic recession. Under the current market dynamics, the Company has heightened its management and mitigation of counterparty credit risk by using credit limits, netting agreements, collateral thresholds, volumetric limits and other mitigation measures, where available. NRG avoids concentration of counterparties whenever possible and applies credit policies that include an evaluation of counterparties financial condition, collateral requirements and the use of standard agreements that allow for netting and other security.

The following table highlights the counterparty credit exposure (net of collateral) to NRG, or Net Exposure, by industry sector and by credit quality. Counterparty credit exposure is NRG s net in-the-money position for a counterparty after giving effect to any netting that is permitted under the enabling agreements and includes all cash flow, mark to market and normal purchase and sale and non-derivative transactions. As of September 30, 2008, aggregate counterparty credit exposure to substantially all counterparties was $1.2 billion and NRG held collateral (cash and letters of credit) against those positions of $236 million resulting in aggregate Net Exposure of $1.0 billion.

Category	Net Exposure (a) (% of Total)

Coal producers	42%
Financial institutions	32%
Utilities, energy, merchants and marketers	17%
ISOs	9%
Total as of September 30, 2008	100%

Category	**Net Exposure (a) (% of Total)**
Investment grade	52%
Non-Investment grade	27%
Non-rated	21%
Total as of September 30, 2008	100%

(a) Excludes California tolling, uranium, coal transportation/railcar leases, New England Reliability Must Run, and Texas Westmoreland coal contracts.

NRG s Net Exposure to those counterparties individually representing more than 10% of its total Net Exposure was $252 million in the aggregate. No counterparty represents more than 15% of total Net Exposure. Approximately three-quarters of NRG s Net Exposure rolls off by the end of 2010. Changes in hedge positions and market prices will affect Net Exposure and counterparty concentration. NRG does not anticipate any material adverse effect on the Company s financial position or results of operations as a result of nonperformance by any of NRG s counterparties.

Fair Value of Derivative Instruments

NRG may enter into long-term power sales contracts, fuel purchase contracts and other energy-related financial instruments to mitigate variability in earnings due to fluctuations in spot market prices, to hedge fuel requirements at generation facilities and protect fuel inventories. 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 include contracts entered into to profit from market price changes as opposed to hedging an exposure, and are subject to limits in accordance with 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. These trading activities are a complement to NRG s energy marketing portfolio.

The tables below disclose the activities that include all derivative contracts accounted for at fair value. Specifically, these tables disaggregate realized and unrealized changes in fair value; identify changes in fair value attributable to changes in valuation techniques; disaggregate estimated fair values as of September 30, 2008, based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts:

Derivative Activity Losses	**(In millions)**
Fair value of contracts as of December 31, 2007	$ (492)
Contracts realized or otherwise settled during the period	163
Changes in fair value	155
Fair value of contracts as of September 30, 2008	$ (174)

(In millions) **Sources of Fair Value Gains/(Losses)**	**Fair Value of Contracts as of September 30, 2008** Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in excess 5 Years	Total Fair Value
Prices actively quoted	$ (8)	$ 7	$	$	$ (1)
Prices provided by other external sources	162	(323)	(19)	(12)	(192)
Prices provided by models and other valuation methods	13	5	1		19
Total	$ 167	$ (311)	$ (18)	$ (12)	$ (174)

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, 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 only 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. The remainder of the assets and liabilities represent 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 11% 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 under a specific master agreement is an asset, the Company is using the counterparty s risk of default. If the exposure under a specific master agreement is a liability, the Company is using NRG s probability of default. 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 September 30, 2008 the credit reserve resulted in a $6 million decrease in fair value which is composed of a $5 million gain in OCI and an $11 million loss in derivative revenue. The fair values in each category reflect the level of forward prices and volatility factors as of September 30, 2008 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.

Table of Contents

The Company has elected to disclose derivative activity on a trade-by-trade basis and does not offset amounts at the counterparty master agreement level. 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 the Item 3 *Commodity Price Risk* section above, 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. However, the Company s trade-by-trade derivative accounting results in a gross-up of the Company s derivative assets and liabilities. Thus, the net derivative assets and liability position is a better indicator of our hedging activity. As of September 30, 2008, NRG s net derivative liability was $174 million, an increase to total fair value of $318 million as compared to December 31, 2007. This increase was primarily driven by decreases in gas and power prices as well as the roll off of deals that settled during the period.

Currency Exchange Risk

NRG may be subject to foreign currency 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. At September 30, 2008, there were no foreign currency options or forward contracts outstanding. Due to 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 September 30, 2008.

ITEM 4 CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of the Company s management, including its principal executive officer, principal financial officer and principal accounting officer, the Company conducted an evaluation 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 have been no changes in the Company s internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the current period covered by this report on Form 10-Q that have 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.

PART II OTHER INFORMATION

ITEM 1 LEGAL PROCEEDINGS

For a discussion of material legal proceedings in which NRG was involved through September 30, 2008, see Note 14, *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 in NRG Energy, Inc. s 2007 Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

ITEM 2 UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Item 2(c) Purchase of Equity securities by NRG

For the period ended October 27, 2008	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 plans or programs
First Quarter 2008 Total	1,281,600	$ 42.73	1,281,600	$ 160,008,401
Second Quarter 2008 Total				160,008,401
July 1 July 31 August 1 August 31 September 1 September 31	3,410,283	38.06	3,410,283	30,226,541
Third Quarter 2008 Total	3,410,283	38.06	3,410,283	30,226,541
October 1 October 27, 2008				
Year-to-date	4,691,883	$ 39.33	4,691,883	$ 30,266,541

On February 28, 2008, NRG announced a $300 million stock buyback as part of the Company s 2008 Capital Allocation Program. As discussed in Note 8, *Changes in Capital Structure*, the Company initiated its 2008 program in December 2007.

ITEM 3 DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4 SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

ITEM 5 OTHER INFORMATION

None.

Table of Contents

ITEM 6 EXHIBITS

Exhibits

3.1	Second Certificate of Amendment to Certificate of Designations relating to the Series 1 Exchangeable Limited Liability Company Preferred Interests of NRG Common Stock Finance I LLC, as filed with the Secretary of State of Delaware on August 8, 2008.
10.1	Amendment Agreement, dated August 8, 2008, to the Note Purchase Agreement by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.
10.2	Preferred Interest Amendment Agreement, dated August 8, 2008, by and among NRG Common Stock Finance I LLC, Credit Suisse International, and Credit Suisse Securities (USA) LLC.
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.

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/ CLINT C. FREELAND
Clint C. Freeland
Chief Financial Officer
(Principal Financial Officer)

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

Date: October 30, 2008

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