UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☑ **Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

☐ **Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the quarterly period ended: June 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 ☑ **No** ☐

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 12 b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ **Accelerated filer** ☐ **Non-accelerated filer** ☐ (Do not check if a smaller reporting company) **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 ☐ **No** ☑

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 ☑ **No** ☐

As of July 25, 2008, there were 235,984,609 shares of common stock outstanding, par value $0.01 per share.

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CAUTIONARY STATEMENT REGARDING FORWARD LOOKING INFORMATION

This Quarterly Report on Form 10-Q 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", "intends", "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 potential inability 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, Integrated Gasification Combined Cycle, or IGCC, 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.

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
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
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

GLOSSARY OF TERMS (cont'd)

NEPOOL	New England Power Pool
NiMo	Niagara Mohawk Power Corporation
NINA	Nuclear Innovation North America LLC
NO_x	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 which matures on February 1, 2013, a $1.3 billion Letter of Credit Facility, 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*"
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

GLOSSARY OF TERMS (cont'd)

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
U.S. GAAP	Accounting principles generally accepted in the United States
VAR	Value at Risk
WCP	WCP (Generation) Holdings, LLC

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PART I — FINANCIAL INFORMATION

ITEM 1 — CONDENSED CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

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

	Three months ended June 30		Six months ended June 30	
(In millions, except for per share amounts)	**2008**	**2007**	**2008**	**2007**
Operating Revenues				
Total operating revenues	$ 1,316	$ 1,536	$ 2,618	$ 2,835
Operating Costs and Expenses				
Cost of operations	1,011	840	1,815	1,621
Depreciation and amortization	161	161	322	321
General and administrative	83	71	158	156
Development costs	4	36	16	59
Total operating costs and expenses	1,259	1,108	2,311	2,157
(Loss)/gain on sale of assets	—	(1)	—	16
Operating Income	57	427	307	694
Other Income/(Expense)				
Equity in (losses)/earnings of unconsolidated affiliates	(19)	8	(23)	21
Other income, net	12	15	21	30
Refinancing expense	—	(35)	—	(35)
Interest expense	(142)	(172)	(295)	(351)
Total other expense	(149)	(184)	(297)	(335)
(Losses)/Income From Continuing Operations Before Income Taxes	(92)	243	10	359
Income tax (benefit)/expense	(53)	100	1	155
(Losses)/Income From Continuing Operations	(39)	143	9	204
Income from discontinued operations, net of income tax expense	168	6	172	10
Net Income	129	149	181	214
Dividends for preferred shares	14	14	28	28
Income Available for Common Stockholders	$ 115	$ 135	$ 153	$ 186
Weighted average number of common shares outstanding — basic	236	240	236	241
(Losses)/income from continuing operations per weighted average common share — basic	$ (0.22)	$ 0.54	$ (0.08)	$ 0.73
Income from discontinued operations per weighted average common share — basic	0.71	0.02	0.73	0.04
Net Income per Weighted Average Common Share — Basic	$ 0.49	$ 0.56	$ 0.65	$ 0.77
Weighted average number of common shares outstanding — diluted	236	288	236	273
(Losses)/income from continuing operations per weighted average common share — diluted	$ (0.22)	$ 0.49	$ (0.08)	$ 0.67
Income from discontinued operations per weighted average common share — diluted	0.71	0.02	0.73	0.04
Net Income per Weighted Average Common Share — Diluted	$ 0.49	$ 0.51	$ 0.65	$ 0.71

See notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions, except shares and par value)	June 30, 2008 (unaudited)	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,263	$ 1,132
Restricted cash	30	29
Accounts receivable, less allowance for doubtful accounts of $1 and $1, respectively	700	482
Inventory	454	451
Derivative instruments valuation	5,716	1,034
Deferred income taxes	977	124
Prepayments and other current assets	640	259
Current assets — discontinued operations	—	51
Total current assets	9,780	3,562
Property, plant and equipment, net of accumulated depreciation of $2,025 and $1,695, respectively	11,430	11,320
Other Assets		
Equity investments in affiliates	454	425
Notes receivable and capital lease, less current portion	515	491
Goodwill	1,786	1,786
Intangible assets, net of accumulated amortization of $411 and $372, respectively	834	873
Nuclear decommissioning trust fund	377	384
Derivative instruments valuation	1,444	150
Other non-current assets	164	176
Intangible assets held-for-sale	5	14
Non-current assets — discontinued operations	—	93
Total other assets	5,579	4,392
Total Assets	$ 26,789	$ 19,274
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 130	$ 466
Accounts payable	490	384
Derivative instruments valuation	6,404	917
Accrued expenses and other current liabilities	508	473
Current liabilities — discontinued operations	—	37
Total current liabilities	7,532	2,277
Other Liabilities		
Long-term debt and capital leases	8,068	7,895
Nuclear decommissioning reserve	316	307
Nuclear decommissioning trust liability	304	326
Deferred income taxes	943	843
Derivative instruments valuation	3,570	759
Out-of-market contracts	418	628
Other non-current liabilities	686	412
Non-current liabilities — discontinued operations	—	76
Total non-current liabilities	14,305	11,246
Total Liabilities	21,837	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	4,134	4,092
Retained earnings	1,424	1,270
Less treasury stock, at cost — 25,832,200 and 24,550,600 shares, respectively	(693)	(638)
Accumulated other comprehensive loss	(1,062)	(115)
Total Stockholders' Equity	4,698	5,504
Total Liabilities and Stockholders' Equity	$ 26,789	$ 19,274

See notes to condensed consolidated financial statements.

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

(In millions) Six months ended June 30,	2008	2007
Cash Flows from Operating Activities		
Net income	$ 181	$ 214
Adjustments to reconcile net income to net cash provided by operating activities		
Distributions and equity in loss/(earnings) of unconsolidated affiliates	32	(7)
Depreciation and amortization	322	322
Amortization of nuclear fuel	30	26
Amortization and write-off of financing costs and debt discount/premiums	14	51
Amortization of intangibles and out-of-market contracts	(147)	(73)
Changes in deferred income taxes and liability for unrecognized tax benefits	96	142
Changes in nuclear decommissioning trust liability	17	20
Changes in derivatives	669	47
Changes in collateral deposits supporting energy risk management activities	(328)	(103)
Loss/(gain) on disposal and sales of assets	2	(16)
Gain on sale of discontinued operations	(270)	—
Gain on sale of emission allowances	(42)	(24)
Amortization of unearned equity compensation	14	14
Cash used by changes in other working capital	(154)	(154)
Net Cash Provided by Operating Activities	436	459
Cash Flows from Investing Activities		
Capital expenditures	(409)	(205)
Increase in restricted cash, net	(1)	(8)
Decrease in notes receivable	21	17
Purchases of emission allowances	(4)	(135)
Proceeds from sale of emission allowances	61	131
Investments in nuclear decommissioning trust fund securities	(285)	(140)
Proceeds from sales of nuclear decommissioning trust fund securities	269	120
Proceeds from sale of discontinued operations, net	229	—
Proceeds from sale of assets	14	29
Proceeds from sale of investments	—	2
Decrease in trust fund balances	—	13
Investment in projects	(17)	—
Other	—	4
Net Cash Used by Investing Activities	(122)	(172)
Cash Flows from Financing Activities		
Payment of dividends to preferred stockholders	(28)	(28)
Payment of financing element of acquired derivatives	(28)	—
Payment for treasury stock	(55)	(215)
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	10	1,411
Payment of deferred debt issuance costs	(2)	—
Payments for short and long-term debt	(188)	(1,459)
Net Cash Used by Financing Activities	(233)	(291)
Change in cash from discontinued operations	43	(6)
Effect of exchange rate changes on cash and cash equivalents	7	4
Net Increase/(Decrease) in Cash and Cash Equivalents	131	(6)
Cash and Cash Equivalents at Beginning of Period	1,132	777
Cash and Cash Equivalents at End of Period	$ 1,263	$ 771

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 June 30, 2008, the results of operations for the three and six months ended June 30, 2008 and 2007, and cash flows for the six months ended June 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.

Investment in Affiliate

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 contribution on April 18, 2008, and expects to contribute another $11 million by year-end, bringing its total expected equity contribution to $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 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, which was a loss of $49 million for the six months ended June 30, 2008, is included in NRG's equity in earnings of Sherbino. NRG's investment at June 30, 2008, net of its promissory note commitment, is a negative $33 million, which is included in "Equity Investments in Affiliates" on the condensed consolidated balance sheet.

Other Cash Flow Information

NRG had non-cash capital additions of $88 million for the six months ended June 30, 2008 for which the associated liability is reflected within accounts payable and 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. This statement requires a business entity to report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. An entity may decide whether to elect the fair value option for each eligible item on its election date, subject to certain requirements described in the statement. 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 establishes principles and 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 11, *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.

Note 2 — Comprehensive Income/Loss

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

	Three months ended June 30,		Six months ended June 30,	
(In millions)	**2008**	**2007**	**2008**	**2007**
Net income	$ 129	$ 149	$ 181	$ 214
Changes in derivative activity	(698)	(41)	(1,000)	(324)
Foreign currency translation adjustment	8	15	50	25
Unrealized gain on available-for-sale securities	1	2	3	2
Other comprehensive loss	$ (689)	$ (24)	$ (947)	$ (297)
Comprehensive (loss)/income	$ (560)	$ 125	$ (766)	$ (83)

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

(In millions) As of June 30,	2008
Accumulated other comprehensive loss as of December 31, 2007	$ (115)
Changes in derivative activity	(1,000)
Foreign currency translation adjustments	50
Unrealized gain on available-for-sale securities	3
Accumulated other comprehensive loss as of June 30, 2008	$(1,062)

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 holds all NRG's interest in ITISA, to Brookfield Renewable Power Inc. (previously Brookfield Power Inc.), a wholly-owned subsidiary of Brookfield Asset Management Inc., and received $288 million in cash proceeds. The sale process removed $163 million of assets, including $59 million of cash, and $122 million of liabilities, including $63 million of debt, from the discontinued assets and liabilities on the condensed consolidated balance sheet as of June 30, 2008. NRG recognized a pre-tax gain of $270 million, including an estimated purchase price adjustment of $9 million as of June 30, 2008, against which $105 million of income taxes were recorded.

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

	Three months ended June 30,		Six months ended June 30,	
(In millions)	2008	2007	2008	2007
Operating revenues	$ 5	$ 12	$ 20	$ 23
Pre-tax income from discontinued operations	274	7	281	12
Income from discontinued operations, net of income tax expense	168	6	172	10

Note 4 — Fair Value of Financial Instruments

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 and exchange-based derivatives.

- 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, non-exchange-based derivatives, mutual funds and fair-value hedges.

- 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.

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 June 30, 2008:

(In millions) As of June 30, 2008	Fair Value Level 1	Level 2	Level 3	Total
Investment in available-for-sale securities (classified within other non-current assets):				
Debt securities	$ —	$ —	$ 29	$ 29
Marketable equity securities	12	—	—	12
Trust fund investments	217	134	28	379
Derivative assets	1,517	5,456	187	7,160
Total assets	$ 1,746	$ 5,590	$ 244	$ 7,580
Derivative liabilities	$ 1,642	$ 8,049	$ 283	$ 9,974

The following table reconciles, for the period ended June 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) Six months ended June 30, 2008	Fair Value Measurement Using Significant Unobservable Inputs (Level 3) 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	(3)	—	(123)	(126)
Included in nuclear decommissioning obligations	—	(1)	—	(1)
Included in other comprehensive income	—	—	14	14
Net sales	—	(9)	(18)	(27)
Transfer into Level 3	—	1	4	5
Ending balance as of June 30, 2008	$ 29	$ 28	$ (96)	$ (39)
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 June 30, 2008	$ (3)	$ —	$ (110)	$ (113)

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 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 discounted cash flow methodology which utilizes significant assumptions that are unobservable.

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, U.S. 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 U.S. 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.

Derivative fair value measurements

The majority of NRG's energy-related 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. 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. The terms for which such price information is available vary by commodity, region and product. The remainder of the assets and liabilities represents contracts for which external valuations are not available, primarily option contracts. These contracts are valued using the Black Scholes model, an industry standard option valuation model. The fair values in each category reflect the level of forward prices and volatility factors as of June 30, 2008 and may change as a result of changes in these factors. NRG's risk management group 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.

Credit Risk Associated with Derivative Instruments

NRG would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of the contracts as of the reporting date. For energy-related derivative instruments, NRG attempts to enter into enabling agreements that allow for payment netting with its counterparties, which reduces NRG's exposure to counterparty credit risk by providing for the offset of amounts payable against amounts receivable to or from the counterparty. Each enabling agreement is commodity specific and so netting is limited to transactions involving that specific commodity except where master netting agreements exist that allow for cross commodity netting. In addition to payment netting language, the credit risk group establishes credit limits and collateral requirements for a counterparty as defined in the enabling agreements. Counterparty credit limits are based on an internal credit assessment that considers a variety of quantitative and qualitative factors, including but not limited to the financial health of the counterparty, credit ratings and risk management capabilities. To the extent that a credit limit is exceeded by the counterparty, NRG may require the counterparty to post collateral to the extent specified in the enabling agreement. NRG's credit risk group monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and portfolio basis.

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 June 30, 2008, the Company included $430 million of cash collateral paid in other current assets and $31 million of cash collateral received in other current liabilities.

Note 5 — 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 June 30, 2008	Energy Commodities	Interest Rate	Total
Accumulated OCI balance at March 31, 2008	$ (493)	$ (74)	$ (567)
Realized from OCI during the period:			
— Due to realization of previously deferred amounts	21	—	21
Mark-to-market of hedge contracts	(763)	44	(719)
Accumulated OCI balance at June 30, 2008	$ (1,235)	$ (30)	$ (1,265)
Losses expected to be realized from OCI during the next 12 months, net of $183 tax	$ (279)	$ (1)	$ (280)

(In millions) Three months ended June 30, 2007	Energy Commodities	Interest Rate	Total
Accumulated OCI balance at March 31, 2007	$ (83)	$ 9	$ (74)
Realized from OCI during the period:			
— Due to realization of previously deferred amounts	(10)	—	(10)
Mark-to-market of hedge contracts	(52)	21	(31)
Accumulated OCI balance at June 30, 2007	$ (145)	$ 30	$ (115)

(In millions) Six months ended June 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	6	—	6
Mark-to-market of hedge contracts	(1,007)	1	(1,006)
Accumulated OCI balance at June 30, 2008	$ (1,235)	$ (30)	$ (1,265)

(In millions) Six months ended June 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	(27)	—	(27)
Mark-to-market of hedge contracts	(311)	14	(297)
Accumulated OCI balance at June 30, 2007	$ (145)	$ 30	$ (115)

As of June 30, 2008 and 2007, the net balances in OCI relating to SFAS 133 were unrecognized losses of approximately $1,265 million and $115 million, which were net of income taxes of $829 million and $77 million, respectively.

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 non-hedge derivatives, derivatives that did not qualify as hedges, and ineffectiveness of hedge derivatives on NRG's statement of operations. These amounts are included within operating revenues.

	Three Months ended June 30,		Six months ended June 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	$ (15)	$ (35)	$ (25)	$ (92)
Reversal of previously recognized unrealized gains on settled positions related to trading activity	(7)	(8)	(12)	(21)
Net unrealized (losses)/gains on open positions related to economic hedges	(162)	100	(259)	21
(Loss)/gain on ineffectiveness associated with trades treated as cash flow hedges	(333)	(21)	(378)	23
Net unrealized gains on open positions related to trading activity	15	7	31	22
Total unrealized mark-to-market results	$ (502)	$ 43	$ (643)	$ (47)

Note 6 — Long Term Debt

Debt Related to NRG Common Stock Finance I, LLC

In March 2008, the Company executed an arrangement with Credit Suisse 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 for any 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.

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 7 — Changes in Capital Structure

The following table reflects the changes in NRG's common stock issued and outstanding during the six months ended June 30, 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	—	—	(1,281,600)	(1,281,600)
Shares issued from LTIP	—	522,490	—	522,490
Balance as of June 30, 2008	500,000,000	261,808,019	(25,832,200)	235,975,819

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. This was followed in January 2008 with the repurchase of an additional 344,000 shares of NRG common stock for approximately $15 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 March 2008, the Company repurchased an additional 937,600 shares of NRG common stock in the open market for approximately $40 million. As of June 30, 2008, NRG had repurchased a total of 3,319,300 shares of NRG common stock at a cost of approximately $140 million as part of its 2008 Capital Allocation Program.

Note 8 — Equity Compensation

Non-Qualified Stock Options, or NQSO's

The following table summarizes the Company's NQSO activity as of June 30, 2008 and the changes during the six 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	1,022,300	42.72	
Forfeited	(28,701)	32.98	
Exercised	(476,052)	15.81	
Outstanding at June 30, 2008	4,097,322	26.04	$ 69
Exercisable at June 30, 2008	2,030,416	$ 17.50	52

The weighted average grant date fair value of NQSO's granted for the six months ending June 30, 2008 was $11.10.

Restricted Stock Units, or RSU's

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

Non-vested Shares	Shares	Weighted Average Grant-Date Fair Value Per Unit
Non-vested as of December 31, 2007	1,588,316	$ 26.99
Granted	145,300	41.79
Vested	(16,400)	18.26
Forfeited	(37,010)	30.74
Non-vested as of June 30, 2008	1,680,206	$ 28.27

Performance Units, or PU's

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

Non-vested Shares	Shares	Weighted Average Grant- Date Fair Value Per Unit
Non-vested as of December 31, 2007	536,764	$ 20.18
Granted	197,900	28.94
Forfeited	(12,500)	20.75
Non-vested as of June 30, 2008	722,164	$ 22.57

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.

Note 9 — Earnings Per Share

Basic earnings per common share is computed by dividing net income/(loss) 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:

	Three Months ended June 30,		Six months ended June 30,	
(In millions, except per share data)	2008	2007	2008	2007
Basic earnings per share				
Numerator:				
(Loss)/income from continuing operations	$ (39)	$ 143	$ 9	$ 204
Preferred stock dividends	(14)	(14)	(28)	(28)
Net (loss)/income available to common stockholders from continuing operations	(53)	129	(19)	176
Discontinued operations, net of income tax expense	168	6	172	10
Net income available to common stockholders	$ 115	$ 135	$ 153	$ 186
Denominator:				
Weighted average number of common shares outstanding	235.9	240.3	236.1	241.1
Basic earnings per share:				
(Loss)/income from continuing operations	$ (0.22)	$ 0.54	$ (0.08)	$ 0.73
Discontinued operations, net of income tax expense	0.71	0.02	0.73	0.04
Net income	$ 0.49	$ 0.56	$ 0.65	$ 0.77
Diluted earnings per share				
Numerator:				
Net (loss)/income available to common stockholders from continuing operations	$ (53)	$ 129	$ (19)	$ 176
Add preferred stock dividends for dilutive preferred stock	—	11	—	8
Adjusted (loss)/income from continuing operations available to common shareholders	(53)	140	(19)	184
Discontinued operations, net of tax	168	6	172	10
Net income available to common stockholders	$ 115	$ 146	$ 153	$ 194
Denominator:				
Weighted average number of common shares outstanding	235.9	240.3	236.1	241.1
Incremental shares attributable to the issuance of equity compensation (treasury stock method)	—	3.7	—	3.5
Incremental shares attributable to embedded derivatives of certain financial instruments (if-converted method)	—	6.5	—	7.4
Incremental shares attributable to assumed conversion features of outstanding preferred stock (if-converted method)	—	37.5	—	21.0
Total dilutive shares	235.9	288.0	236.1	273.0
Diluted earnings per share:				
(Loss)/income from continuing operations available to common shareholders	$ (0.22)	$ 0.49	$ (0.08)	$ 0.67
Income from discontinued operations, net of tax	0.71	0.02	0.73	0.04
Net income	$ 0.49	$ 0.51	$ 0.65	$ 0.71

For the three and six months ended June 30, 2008, basic and diluted per share amounts were the same within each period reported because potential common shares had an anti-dilutive effect on loss from continuing operations available to common shares and were excluded from the computation.

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:

	Three months ended June 30,		Six months ended June 30,	
(In millions of shares)	**2008**	**2007**	**2008**	**2007**
Equity compensation	7.5	—	7.5	0.5
4.0% convertible preferred stock	21.0	—	21.0	—
5.75% convertible preferred stock	16.5	—	16.5	16.5
Embedded derivative of 3.625% convertible perpetual preferred stock	16.0	11.8	16.0	11.2
Embedded derivative of preferred interests and notes issued by CSF I and CSF II	18.3	16.0	18.3	15.7
Total	79.3	27.8	79.3	43.9

Note 10 — 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.

(In millions) Three months ended June 30, 2008	Wholesale Power Generation								
	Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
Operating revenues	$ 751	$ 265	$ 172	$ 49	$ 43	$ 34	$ 3	$ (1)	$ 1,316
Depreciation and amortization	113	25	17	3	—	2	1	—	161
Equity in (losses)/earnings of unconsolidated affiliates	(32)	—	—	(1)	14	—	—	—	(19)
Income/(loss) from continuing operations before income taxes	14	(45)	(6)	13	23	2	(83)	(10)	(92)
Income from discontinued operations, net of income taxes	—	—	—	—	168	—	—	—	168
Net income/(loss)	$ 13	$ (45)	$ (6)	$ 13	$ 186	$ 2	$ (24)	$ (10)	$ 129
Total assets	$ 12,105	$ 1,334	$ 1,804	$ 579	$ 1,081	$ 277	$ 18,247	$ (8,638)	$ 26,789

(In millions) Three months ended June 30, 2007	Wholesale Power Generation								
	Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
Operating revenues	$ 875	$ 395	$ 164	$ 29	$ 32	$ 37	$ 17	$ (13)	$ 1,536
Depreciation and amortization	114	24	17	1	—	3	2	—	161
Equity in (losses)/earnings of unconsolidated affiliates	—	—	—	(1)	9	—	—	—	8
Income/(loss) from continuing operations before income taxes	236	110	(4)	8	16	5	(116)	(12)	243
Income from discontinued operations, net of income taxes	—	—	—	—	6	—	—	—	6
Net income/(loss)	$ 134	$ 110	$ (4)	$ 8	$ 17	$ 5	$ (109)	$ (12)	$ 149

(In millions) Six months ended June 30, 2008	Wholesale Power Generation Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
Operating revenues	$ 1,400	$ 625	$ 351	$ 87	$ 81	$ 78	$ (2)	$ (2)	$ 2,618
Depreciation and amortization	226	51	34	4	—	5	2	—	322
Equity in (losses)/earnings of unconsolidated affiliates	(50)	—	—	(3)	30	—	—	—	(23)
Income/(loss) from continuing operations before income taxes	81	14	33	25	47	7	(187)	(10)	10
Income from discontinued operations, net of income taxes	—	—	—	—	172	—	—	—	172
Net income/(loss)	$ 50	$ 14	$ 33	$ 25	$ 210	$ 7	$ (148)	$ (10)	$ 181

(In millions) Six months ended June 30, 2007	Wholesale Power Generation Texas	Northeast	South Central	West	International	Thermal	Corporate	Elimination	Total
Operating revenues	$ 1,570	$ 737	$ 314	$ 57	$ 64	$ 86	$ 22	$ (15)	$ 2,835
Depreciation and amortization	228	49	34	1	—	6	3	—	321
Equity in (losses)/earnings of unconsolidated affiliates	—	—	—	(3)	24	—	—	—	21
Income/(loss) from continuing operations before income taxes	349	148	6	13	35	28	(208)	(12)	359
Income from discontinued operations, net of income taxes	—	—	—	—	10	—	—	—	10
Net income/(loss)	$ 194	$ 148	$ 6	$ 13	$ 34	$ 28	$ (197)	$ (12)	$ 214

Note 11 — Income Taxes

Income tax (benefit)/expense from continuing operations for the three months and six months ended June 30, 2008 was ($53) million and $1 million, respectively, compared to $100 million and $155 million for the three and six months ended June 30, 2007, respectively. The income tax expense for the three months and six months ended June 30, 2008 included domestic tax benefit of ($58) million and ($8) million, respectively, and foreign tax expense of $5 million and $9 million, respectively. The income tax expense for the three and six months ended June 30, 2007 included domestic tax expense of $95 million and $143 million, respectively, and foreign tax expense of $5 million and $12 million, respectively.

A reconciliation of the U.S. statutory rate to NRG's effective tax rate from continuing operations is as follows:

(In millions except percentages) Six months ended June 30,	2008	2007
Income from continuing operations before income taxes	$ 10	$ 359
Tax at 35%	4	126
State taxes	(1)	16
Valuation allowance	(1)	1
Foreign operations	(8)	(1)
Foreign dividend	5	8
Non-deductible interest	5	5
Other permanent differences including subpart F income	(3)	—
Income tax expense	$ 1	$ 155
Effective income tax rate	10.0%	43.2%

The effective income tax rate for the six months ended June 30, 2008 and 2007 differs from the U.S. 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 U.S. statutory rate.

Deferred tax assets and valuation allowance

Net deferred tax balance — As of June 30, 2008, NRG recorded a net deferred tax asset of $587 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 $552 million of tax assets, thus a valuation allowance has remained, resulting in a net deferred tax asset of $35 million.

NOL carryforwards — As of June 30, 2008, the Company had cumulative foreign NOL carryforwards of $307 million, of which $78 million will expire starting in 2011 through 2017 and $229 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 June 30, 2008, NRG has recorded a $239 million non-current tax liability for unrecognized tax benefits, resulting from taxable earnings for the period, which for financial statement purposes there are insufficient NOLs available to offset. NRG accrued interest and penalties related to these unrecognized tax benefits of approximately $4 million as of June 30, 2008. The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. For the six months ended June 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 U.S. federal jurisdiction and various state and foreign jurisdictions including major operations located in Germany and Australia. The Company is no longer subject to U.S. 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 is expected to commence in third quarter 2008 and continue for approximately 18 to 24 months.

Note 12 — 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 six months ended June 30, 2008 was $23 million. NRG expects to make $42 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 June 30,		Six months ended June 30,	
(In millions)	2008	2007	2008	2007
Service cost benefits earned	$ 3	$ 4	$ 7	$ 8
Interest cost on benefit obligation	4	5	9	9
Net gain	(1)	—	(1)	—
Expected return on plan assets	(3)	(3)	(7)	(6)
Net periodic benefit cost	$ 3	$ 6	$ 8	$ 11

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 June 30,		Six months ended June 30,	
(In millions)	2008	2007	2008	2007
Service cost benefits earned	$ —	$ —	$ 1	$ 1
Interest cost on benefit obligation	2	1	3	2
Net periodic benefit cost	$ 2	$ 1	$ 4	$ 3

STP Defined Benefit Plans

NRG has a 44% undivided ownership interest in South Texas Project, or STP. South Texas Project Nuclear Operating Company, or STPNOC, which operates and maintains STP, provides its employees a defined benefit pension plan as well as postretirement health and welfare benefits. Although NRG does not sponsor the STP plan, it reimburses STPNOC for 44% of the contributions made towards its retirement plan obligations. The total amount of employer contributions reimbursed to STPNOC for the six months ended June 30, 2008 was $2 million. The Company recognized net periodic costs related to its 44% interest in STP defined benefits plans of $2 million and $2 million for the three months ended June 30, 2008 and 2007, respectively. The Company recognized net periodic costs related to its 44% interest in STP defined benefits plan of $4 million and $3 million for the six months ended June 30, 2008 and 2007, respectively.

Note 13 — 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 six months ended June 30, 2008 with total commitments of approximately $135 million, spanning from 2008 through 2011. In addition, NRG natural gas purchase commitments increased from $562 million as of December 31, 2007 to $844 million as of June 30, 2008 over the next two years due to higher forward prices.

First and Second Lien Structure

NRG has granted first and second priority liens to certain counterparties on substantially all of the Company's assets in the United States in order to secure certain obligations, which are primarily long-term in nature under certain power 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 these agreements. 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.

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.

As of June 30, 2008, and July 25, 2008, the net discounted exposure less collateral posted on the agreements and hedges that were subject to the first lien structure were approximately $2.6 billion and $688 million, respectively. As of June 30, 2008, and July 25, 2008, the net discounted exposure less collateral posted on the agreements and hedges that were subject to the second lien structure were approximately $982 million and $299 million, respectively.

***Repowering*NRG**

NRG has made non-refundable payments relating to *Repowering*NRG projects totaling approximately $123 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 $215 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.

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 effect NRG's consolidated financial position, results of operations, or cash flows.

California Department of Water Resources

On December 19, 2006, the U.S. 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 U.S. 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. FERC has yet to take any action as a result of the decision.

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. 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.

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 U.S. 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 U.S. 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 U.S. 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 U.S. 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 for the six months ended June 30, 2008.

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 July 25, 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.

Note 14 — 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 U.S. 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 that is in the process of being implemented 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 court, although one procedural argument relating to future challenges by non-settling parties was sustained.

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 has sought rehearing on the refund issue, thus resolving the contingency. NRG, as well as other market participants, have sought rehearing of other aspects of the March 7 order.

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 has agreed to the NYISO's assessment. NRG had previously established an adequate accrual for this matter.

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. If the complaint is granted and resettlement of the market occurs, which is not viewed as likely at this time, suppliers including NRG would face a refund obligation since the complaint seeks an effective date of June 1, 2008 for its proposed rule changes.

Note 15 — 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 U.S. 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 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.

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 RGGI will have to procure one allowance for every U.S. ton of CO_2 emitted with true up for 2009-2011 occurring in 2012. The RGGI states plan to provide allowances through quarterly auctions, the first of which could be held on September 25, 2008. NRG units located in Connecticut, Delaware, Maryland, Massachusetts and New York emitted approximately 13 million US tons in 2007. NRG believes that to the extent CO_2 will not be fully reflected in wholesale electricity prices, the direct financial impact on the Company is likely to be negative as costs will be incurred in the course of securing the necessary allowances and offset 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 analyzing the scope and impact of the NRDA.

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 16 — 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 six months ended June 30, 2008, NRG had net increases to its guarantee obligations under other commercial arrangements of approximately $701 million. In addition, for the six months ended June 30, 2008, synthetic letter of credit availability decreased $230 million due to the issuance of a letter of credit of $143 million to support the Company's commercial operation activity with marginable counterparties and $87 million to support NRG's capital contribution commitment to the Sherbino Wind Farm equity investment, hereinafter discussed.

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Note 17 — Condensed Consolidating Financial Information

As of June 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 June 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 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.
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
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

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.

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

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(a)	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 1,222	$ 94	$ —	$ —	$ 1,316
Operating Costs and Expenses					
Cost of operations	947	64	1	(1)	1,011
Depreciation and amortization	153	8	—	—	161
General and administrative	18	(7)	72	—	83
Development costs	(5)	1	8	—	4
Total operating costs and expenses	1,113	66	81	(1)	1,259
Operating Income/(Loss)	109	28	(81)	1	57
Other Income/(Expense)					
Equity in earnings/(losses) of consolidated subsidiaries	138	(32)	305	(411)	—
Equity in losses of unconsolidated affiliates	(1)	(18)	—	—	(19)
Other income/(expense), net	14	(4)	3	(1)	12
Interest expense	(51)	(16)	(75)	—	(142)
Total other income/(expense)	100	(70)	233	(412)	(149)
Income/(Losses) From Continuing Operations Before Income Taxes	209	(42)	152	(411)	(92)
Income tax (benefit)/expense	46	(25)	(74)	—	(53)
Income/(Losses) From Continuing Operations	163	(17)	226	(411)	(39)
Income/(Losses) from discontinued operations, net of income taxes	—	265	(97)	—	168
Net Income	$ 163	$ 248	$ 129	$ (411)	$ 129

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

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

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(a)	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 2,423	$ 195	$ —	$ —	$ 2,618
Operating Costs and Expenses					
Cost of operations	1,681	132	3	(1)	1,815
Depreciation and amortization	306	14	2	—	322
General and administrative	31	(4)	131	—	158
Development costs	(5)	3	18	—	16
Total operating costs and expenses	2,013	145	154	(1)	2,311
Operating Income/(Loss)	410	50	(154)	1	307
Other Income/(Expense)					
Equity in earnings/(losses) of consolidated subsidiaries	210	(50)	450	(610)	—
Equity in losses of unconsolidated affiliates	(3)	(20)	—	—	(23)
Other income/(expense), net	15	(1)	8	(1)	21
Interest expense	(102)	(34)	(159)	—	(295)
Total other income/(expense)	120	(105)	299	(611)	(297)
Income/(Losses) From Continuing Operations Before Income Taxes	530	(55)	145	(610)	10
Income tax expense/(benefit)	167	(33)	(133)	—	1
Income/(Losses) From Continuing Operations	363	(22)	278	(610)	9
Income/(Losses) from discontinued operations, net of income taxes	—	269	(97)	—	172
Net Income	$ 363	$ 247	$ 181	$ (610)	$ 181

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

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

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(a)	Consolidated Balance
ASSETS					
Current Assets					
Cash and cash equivalents	$ 1	$ 179	$ 1,083	$ —	$ 1,263
Restricted cash	1	29	—	—	30
Accounts receivable, net	668	32	—	—	700
Inventory	442	12	—	—	454
Derivative instruments valuation	5,712	4	—	—	5,716
Deferred income taxes	991	(18)	4	—	977
Prepayments and other current assets	399	(447)	957	(269)	640
Total current assets	8,214	(209)	2,044	(269)	9,780
Net property, plant and equipment	10,772	634	24	—	11,430
Other Assets					
Investment in subsidiaries	759	(32)	8,289	(9,016)	—
Equity investments in affiliates	25	429	—	—	454
Notes receivable and capital lease, less current portion	441	515	3,335	(3,776)	515
Goodwill	1,786	—	—	—	1,786
Intangible assets, net	820	14	—	—	834
Nuclear decommissioning trust	377	—	—	—	377
Derivative instruments valuation	1,444	—	—	—	1,444
Other non-current assets	7	1	156	—	164
Intangible assets held-for-sale	5	—	—	—	5
Total other assets	5,664	927	11,780	(12,792)	5,579
Total Assets	$ 24,650	$ 1,352	$ 13,848	$ (13,061)	$ 26,789
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 83	$ 99	$ 31	$ (83)	$ 130
Accounts payable	411	61	18	—	490
Derivative instruments valuation	6,402	—	2	—	6,404
Accrued expenses and other current liabilities	352	31	311	(186)	508
Total current liabilities	7,248	191	362	(269)	7,532
Other Liabilities					
Long-term debt and capital leases	3,250	832	7,762	(3,776)	8,068
Nuclear decommissioning reserve	316	—	—	—	316
Nuclear decommissioning trust liability	304	—	—	—	304
Deferred income taxes	642	(179)	480	—	943
Derivative instruments valuation	3,502	15	53	—	3,570
Out-of-market contracts	418	—	—	—	418
Other non-current liabilities	381	59	246	—	686
Total non-current liabilities	8,813	727	8,541	(3,776)	14,305
Total liabilities	16,061	918	8,903	(4,045)	21,837
Minority interest	7	—	—	—	7
3.625% Preferred Stock	—	—	247	—	247
Stockholders' Equity	8,582	434	4,698	(9,016)	4,698
Total Liabilities and Stockholders' Equity	$ 24,650	$ 1,352	$ 13,848	$ (13,061)	$ 26,789

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

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Six Months Ended June 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	$ 363	$ 247	$ 181	$ (610)	$ 181
Adjustments to reconcile net income to net cash provided by operating activities:					
Distributions and equity in (earnings)/losses of unconsolidated affiliates and consolidated subsidiaries	(207)	79	(450)	610	32
Depreciation and amortization	306	14	2	—	322
Amortization of nuclear fuel	30	—	—	—	30
Amortization of financing costs and debt discount	—	3	11	—	14
Amortization of intangibles and out-of-market contracts	(147)	—	—	—	(147)
Changes in deferred income taxes and liability for unrecognized tax benefits	(159)	(52)	307	—	96
Changes in nuclear decommissioning liability	17	—	—	—	17
Changes in derivatives	664	5	—	—	669
Changes in collateral deposits supporting energy risk management activities	(328)	—	—	—	(328)
Loss on disposal and sales of assets	2	—	—	—	2
Gain on sale of discontinued operations	—	(270)	—	—	(270)
Gain on sale of emission allowances	(42)	—	—	—	(42)
Amortization of unearned equity compensation	—	—	14	—	14
Cash provided by/(used by) changes in other working capital, net of dispositions affects	284	96	(534)	—	(154)
Net Cash Provided (Used) by Operating Activities	783	122	(469)	—	436
Cash Flows from Investing Activities					
Intercompany (loans to)/receipts from subsidiaries	(81)	—	444	(363)	—
Capital expenditures	(201)	(204)	(4)	—	(409)
Increase in restricted cash	—	(1)	—	—	(1)
Decrease in notes receivable	—	21	—	—	21
Purchases of emission allowances	(4)	—	—	—	(4)
Proceeds from sale of emission allowances	61	—	—	—	61
Investment in nuclear decomissioning trust fund securities	(285)	—	—	—	(285)
Proceeds from sales of nuclear decomissioning trust fund securities	269	—	—	—	269
Proceeds from sale of discontinued operations, net	—	(59)	288	—	229
Proceeds from sale of assets	14	—	—	—	14
Investment in projects	—	—	(17)	—	(17)
Net Cash Provided (Used) by Investing Activities	(227)	(243)	711	(363)	(122)
Cash Flows from Financing Activities					
(Payments)/proceeds for intercompany loans	(523)	79	81	363	—
Payments for dividends to preferred stockholders	—	—	(28)	—	(28)
Receipt/(payment) of intercompany dividend	—	17	(17)	—	—
Payment of financing element of acquired derivatives	(28)	—	—	—	(28)
Payments for treasury stock	—	—	(55)	—	(55)
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	—	10	—	—	10
Payments for deferred debt issuance costs	—	—	(2)	—	(2)
Payments for short and long-term debt	—	(30)	(158)	—	(188)
Net Cash Provided (Used) by Financing Activities	(551)	126	(171)	363	(233)
Change in cash from discontinued operations	—	43	—	—	43
Effect of exchange rate changes on cash and cash equivalents	—	7	—	—	7
Net Increase in Cash and Cash Equivalent	5	55	71	—	131
Cash and Cash Equivalents at Beginning of Period	(4)	124	1,012	—	1,132
Cash and Cash Equivalents at End of Period	$ 1	$ 179	$ 1,083	$ —	$ 1,263

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

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

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(a)	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 1,451	$ 85	$ —	$ —	$ 1,536
Operating Costs and Expenses					
Cost of operations	777	62	1	—	840
Depreciation and amortization	154	7	—	—	161
General and administrative	20	5	46	—	71
Development costs	32	—	4	—	36
Total operating costs and expenses	983	74	51	—	1,108
Loss on sale of assets	(1)	—		—	(1)
Operating Income/(Loss)	467	11	(51)	—	427
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	22	—	253	(275)	—
Equity in (losses)/earnings of unconsolidated affiliates	(1)	9	—	—	8
Gain on sale of equity method investment	—	1	—	—	1
Other income, net	2	10	7	(5)	14
Refinancing expense	—	—	(35)	—	(35)
Interest expense	(68)	(20)	(89)	5	(172)
Total other income/(expense)	(45)	—	136	(275)	(184)
Income From Continuing Operations Before Income Taxes	422	11	85	(275)	243
Income tax expense/(benefit)	157	7	(64)	—	100
Income From Continuing Operations	265	4	149	(275)	143
Income from discontinued operations, net of income taxes	—	6	—	—	6
Net Income	$ 265	$ 10	$ 149	$ (275)	$ 149

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

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

(In millions)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(a)	Consolidated Balance
Operating Revenues					
Total operating revenues	$ 2,650	$ 185	$ —	$ —	$ 2,835
Operating Costs and Expenses					
Cost of operations	1,478	140	3	—	1,621
Depreciation and amortization	307	13	1	—	321
General and administrative	46	9	101	—	156
Development costs	55	—	4	—	59
Total operating costs and expenses	1,886	162	109	—	2,157
Gain/(loss) on sale of assets	17	—	(1)	—	16
Operating Income/(Loss)	781	23	(110)	—	694
Other Income/(Expense)					
Equity in earnings of consolidated subsidiaries	54	—	409	(463)	—
Equity in (losses)/earnings of unconsolidated affiliates	(3)	24	—	—	21
Gain on sale of equity method investment	—	1	—	—	1
Other income, net	4	18	17	(10)	29
Refinancing expense	—	—	(35)	—	(35)
Interest expense	(138)	(44)	(179)	10	(351)
Total other income/(expense)	(83)	(1)	212	(463)	(335)
Income From Continuing Operations Before Income Taxes	698	22	102	(463)	359
Income tax expense/(benefit)	256	11	(112)	—	155
Income From Continuing Operations	442	11	214	(463)	204
Income from discontinued operations, net of income taxes	—	10	—	—	10
Net Income	$ 442	$ 21	$ 214	$ (463)	$ 214

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

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
Collateral on deposit 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
Accrued expenses and other current liabilities	335	62	145	(69)	473
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.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Six Months Ended June 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	$ 444	$ 19	$ 214	$ (463)	$ 214
Adjustments to reconcile net income to net cash provided by operating activities:					
Distributions and equity (earnings)/losses of unconsolidated affiliates and consolidated subsidiaries	251	(10)	(107)	(141)	(7)
Depreciation and amortization	307	14	1	—	322
Amortization of nuclear fuel	26	—	—	—	26
Amortization of financing costs and debt discount	—	3	48	—	51
Amortization of intangibles and out-of-market contracts	(73)	—	—	—	(73)
Amortization of unearned equity compensation	—	—	14	—	14
Changes in deferred income taxes	35	169	(62)	—	142
Changes in nuclear decommissioning trust liability	20	—	—	—	20
Changes in derivatives	66	4	(23)	—	47
Gain on disposal and sale of assets	(16)	—	—	—	(16)
Gain on sale of emission allowances	(24)	—	—	—	(24)
Changes in collateral deposits supporting energy risk management activities	(103)	—	—	—	(103)
Cash (used)/provided by changes in other working capital, net of dispositions affects	(191)	(71)	108	—	(154)
Net Cash (Used)/Provided by Operating Activities	742	128	193	(604)	459
Cash Flows from Investing Activities					
Intercompany (loans to)/receipts from subsidiaries	(37)	(47)	318	(234)	—
Capital expenditures	(123)	(80)	(2)	—	(205)
Increase in restricted cash	—	(8)	—	—	(8)
Decrease in notes receivable	—	17		—	17
Purchases of emission allowances	(135)	—	—	—	(135)
Proceeds from the sale of emission allowances	131	—	—	—	131
Proceeds from the sale of investments	—	2	—	—	2
Proceeds from the sale of assets	29	—	—	—	29
Purchase of nuclear decomissioning trust fund securities	(140)	—	—	—	(140)
Proceeds from sales of nuclear decomissioning trust fund securities	120	—	—	—	120
Decrease in trust fund balances	13	—	—	—	13
Other	—	—	4	—	4
Net Cash (Used)/Provided by Investing Activities	(142)	(116)	320	(234)	(172)
Cash Flows from Financing Activities					
Payments/proceeds for intercompany loans	(318)		84	234	—
Payments from intercompany dividends	(302)	(302)	—	604	—
Payment for dividends to preferred stockholders	—	—	(28)	—	(28)
Payments for treasury stock	—	—	(215)	—	(215)
Proceeds from issuance of long-term debt	—	—	1,411	—	1,411
Payments for short and long-term debt	(1)	(30)	(1,428)	—	(1,459)
Net Cash (Used)/Provided by Financing Activities	(621)	(332)	(176)	838	(291)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	4	—	—	4
Change in Cash from Discontinued Operations	—	(6)	—	—	(6)
Net Increase/(Decrease) in Cash and Cash Equivalents	(21)	(322)	337	—	(6)
Cash and Cash Equivalents at Beginning of Period	20	414	343	—	777
Cash and Cash Equivalents at End of Period	$ (1)	$ 92	$ 680	$ —	$ 771

(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 June 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 24,005 MW and approximately 822 MW under construction, which includes partnership interests. 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 22,925 MW of generation capacity in 177 active generating units at 43 plants. These power generation facilities are primarily located in Texas (approximately 10,800 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 and provides a stable source of cash flow. In addition, NRG's generation portfolio provides the Company with opportunities to capture additional revenues by selling power during periods of peak demand, offering capacity or similar products to retail electric providers and others, and providing ancillary services to support system reliability.

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 2004 baseline, with the exception of the Texas region where benefits are measured using 2005 as the 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 to 2008. During the fourth quarter 2008, the Company expects to launch the next phase of the program under the banner "*FOR*NRG 2.0."

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.

3. **econrg** represents NRG's commitment to environmentally responsible power generation. econrg seeks to find ways to meet the challenges of climate change, clean air and water, and protecting our natural resources while taking advantage of business opportunities. This initiative builds upon its 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.*

As you read this discussion and analysis, refer to the consolidated statements of income which present the results of operations for the three and six months ended June 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.

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. Furthest along is the Northeast where the ten participating states are preparing for implementation of RGGI, with the first auction of CO_2 allowances in September 2008 and an effective start date of 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 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. In June 2008, the Senate debated, but failed to pass the Lieberman-Warner Climate Security Act. While it is not clear when Congress will succeed in passing legislation, the Company anticipates that the basic architecture of the Lieberman-Warner bill is likely to be the basis for future legislative proposals. To the extent that it does, the Company expects that such legislation will have a minimal negative impact on its financial performance through the next decade. Thereafter, the impact would depend on the level of success of 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 11, 2008, the USEPA released a draft Advance Notice of Proposed Rulemaking, or ANPR, inviting public comment on the benefits and ramifications of regulating GHG emissions under the CAA. A final version and then a 120 day comment period will follow. 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 would have applied 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 vacated CAIR in its entirety. The result is that the existing NO_x State Implementation Plans and Acid Rain SO_2 trading programs will remain unaltered and in place past January 1, 2009 and 2010, respectively. 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.

At June 30, 2008, NRG Texas held a bank of emissions allowances with a net carrying value of $759 million, consisting of $508 million for SO_2 and $251 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, based on our assessment of the long term sustainability of the SO_2 program and prices. NRG Texas' NO_x allowances are related to a local area-specific NO_x program and thus are unaffected by CAIR and the D.C. Circuit Court ruling.

On March 12, 2008, the USEPA strengthened the primary and secondary ground level ozone National Ambient Air Quality Standards, or NAAQS, (8 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 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 U.S. of CO_2 ton emitted with true up for 2009-2011 occurring in 2012. The RGGI states plan to provide allowances through quarterly auctions, the first of which could be held on September 25, 2008. NRG units located in Connecticut, Delaware, Maryland, Massachusetts and New York emitted approximately 13 million US tons in 2007. NRG believes that to the extent CO_2 will not be fully reflected in wholesale electricity prices, the direct financial impact on the Company is likely to be negative as costs will be incurred in the course of securing the necessary 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. NRG is contesting these rule changes which, as proposed, would require the Norwalk Power units to operate at less than their cost of service.

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, the PUCT tentatively approved a significant transmission expansion plan to provide for the delivery of approximately 18,500 MWs 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 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.

West Region

CAISO has indicated that its Market Redesign and Technology Upgrade, or MRTU, program will not be implemented before the summer peak season and is tentatively targeting November 1, 2008 for implementation. On September 21, 2006, FERC conditionally accepted the MRTU proposal. 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.

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Consolidated Results of Operations

The following table provides selected financial information for the Company:

(In millions except otherwise noted)	Three months ended June 30, 2008	2007	Change %	Six months ended June 30, 2008	2007	Change %
Operating Revenues						
Energy revenue	$ 1,373	$ 1,055	30%	$ 2,298	$ 1,991	15%
Capacity revenue	334	289	16	681	562	21
Risk management activities	(588)	52	N/A	(717)	9	N/A
Contract amortization	88	67	31	157	119	32
Thermal revenue	23	29	(21)	59	70	(16)
Other revenues	86	44	95	140	84	67
Total operating revenues	1,316	1,536	(14)	2,618	2,835	(8)
Operating Costs and Expenses						
Cost of operations	1,011	840	20	1,815	1,621	12
Depreciation and amortization	161	161	—	322	321	—
General and administrative	83	71	17	158	156	1
Development costs	4	36	(89)	16	59	(73)
Total operating costs and expenses	1,259	1,108	14	2,311	2,157	7
Gain/(loss) on sale of assets	—	(1)	N/A	—	16	N/A
Operating income	57	427	(87)	307	694	(56)
Other Income/(Expense)						
Equity in (losses)/earnings of unconsolidated affiliates	(19)	8	N/A	(23)	21	N/A
Other income, net	12	15	(20)	21	30	(30)
Refinancing expense	—	(35)	N/A	—	(35)	N/A
Interest expense	(142)	(172)	(17)	(295)	(351)	(16)
Total other expense	(149)	(184)	(19)	(297)	(335)	(11)
Income/(Loss) from Continuing Operations before income tax expense	(92)	243	N/A	10	359	(97)
Income tax (benefit)/expense	(53)	100	N/A	1	155	(99)
Income/(Loss) from Continuing Operations	(39)	143	N/A	9	204	(96)
Income from discontinued operations, net of income tax expense	168	6	N/A	172	10	N/A
Net Income	$ 129	$ 149	(13)	$ 181	$ 214	(15)
Business Metrics						
Average natural gas price — Henry Hub ($/MMBtu)	11.32	7.65	48%	9.95	7.42	34%

NA — Not Applicable

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

Operating Revenues

Operating revenues decreased by $220 million during the three months ended June 30, 2008 compared to the same period in 2007.

- *Energy revenues* — increased by $318 million during the three months ended June 30, 2008 compared to the same period in 2007:
  - o *Texas* — increased by $238 million due to a $131 million increase primarily attributable to 24% higher generation from gas plants and a 2% increase in coal plant generation. Additionally there was a $107 million increase as a result of higher merchant prices of $52 per MWh partially offset by a $7 per MWh reduction in contracted energy prices.

- o *Northeast* — increased by $31 million due to a $36 million increase in energy prices and a $16 million increase as a result of a net 6% increase in generation. These increases were offset by an $18 million reduction in contracted energy revenues driven by higher cost required to service the PJM contracts.
- o *South Central* — increased by $29 million due to $25 million in higher merchant energy revenues and $3 million of improved contract energy revenues. The growth in merchant energy revenues reflects a 5% rise in coal generation driven by fewer outages. Merchant energy MWh sold increased 16% while contracted MWh sold decreased by 3%. The increase in contracted energy revenues was driven by higher fuel cost pass-through adjustments for the region's cooperative customers.
- o *West* — increased by $13 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 by $45 million during the three months ended June 30, 2008 compared to the same period in 2007:
  - o *Texas* — increased by $28 million due to a greater proportion of base-load contracts which contain a capacity component.
  - o *Northeast* — increased by $8 million due to $10 million in additional revenues from PJM assets reflecting recognition of a full quarter's revenue from the RPM capacity market and $2 million additional revenues in NEPOOL assets reflecting full recognition on the Norwalk RMR contract. These increases were partially offset by a $4 million decline in NYISO capacity revenues due to unfavorable contract prices.
  - o *South Central* — increased by $3 million due to new peak load set by the region's cooperative customers which resulted in $4 million of additional capacity payments offset by a $1 million decrease to capacity payments from other contract customers.
  - o *West* — increased by $2 million primarily due to $7 million in additional revenue from a new tolling agreement at the region's Long Beach plant offset by a $3 million decrease related to the expiration of an El Segundo Resource Adequacy contract.
- *Contract amortization revenues* — increased by $21 million during the three months ended June 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 purchase accounting of the Texas Genco LLC, or Texas Genco, acquisition.
- *Other revenues* — increased by $42 million during the three months ended June 30, 2008 compared to the same period in 2007. The increases arose from greater ancillary revenue of $19 million, increased activity in the trading of emission allowances and carbon financial instruments of $9 million, and increased activity in trading gas and coal of $12 million.

- *Risk management activities* — revenues from risk management activities include all derivative activity that does not qualify for hedge accounting and the ineffective portion associated with hedged transactions. Such revenues decreased by $640 million during the three months ended June 30, 2008 compared to the same period in 2007. The breakdown of changes by region is as follows:

	Three months ended June 30, 2008				Three months ended June 30 2007			
(In millions)	**Texas**	**Northeast**	**South Central**	**Total**	**Texas**	**Northeast**	**South Central**	**Total**
Net gains/(losses) on settled positions, or *financial revenues*	$ (48)	$ (34)	$ (4)	$ (86)	$ (2)	$ 7	$ 4	$ 9
Mark-to-market results								
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	(9)	(6)	—	(15)	(23)	(12)	—	(35)
Reversal of previously recognized unrealized gains on settled positions related to trading activity	—	(3)	(4)	(7)	—	(3)	(5)	(8)
Net unrealized gains/(losses) on open positions related to economic hedges	(382)	(113)	—	(495)	48	31	—	79
Net unrealized gains/(losses) on open positions related to trading activity	20	10	(15)	15	3	1	3	7
Subtotal mark-to-market results	(371)	(112)	(19)	(502)	28	17	(2)	43
Total gain/(loss)	$ (419)	$ (146)	$ (23)	$ (588)	$ 26	$ 24	$ 2	$ 52

NRG's second quarter 2008 loss is comprised of $502 million of mark-to-market losses and $86 million in settled losses, or financial revenue. Of the $502 million of mark-to-market losses, $15 million represents the reversal of mark-to-market gains recognized on economic hedges and $7 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 $495 million loss from economic hedge positions included a $162 million decrease in value of forward sales of electricity and fuel due to higher power and gas prices and a $333 million loss primarily from hedge accounting ineffectiveness related to gas trades in the Texas region which was driven by increasing gas prices while power prices rose at a slower pace.

Since these hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, 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. These changes are recorded net of both financial instruments hedges that are afforded hedge accounting treatment and cost of energy. During and prior to 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 increased, resulting in the recognition of unrealized mark-to-market forward losses. In the second quarter 2007, NRG recognized forward mark-to-market gains as forward prices of electricity decreased relative to its forward positions.

Cost of Operations

Cost of operations increased by $171 million during the three months ended June 30, 2008 compared to the same period in 2007.

- *Cost of energy* — increased by $177 million during the three months ended June 30, 2008 compared to the same period in 2007 due to:
  - *Texas* — increased by $103 million due to higher natural gas costs of $104 million reflecting a $3.75 per MMBtu rise in average natural gas prices along with a 24% increase in gas-fired generation. Ancillary services and other costs also increased by $6 million as a result of higher purchased ancillary services and ERCOT ISO fees. Coal costs increased by $5 million

due to a 2% increase in coal-fired generation and higher coal prices. Additionally, nuclear fuel rose by $2 million due to a 1% increase in generation. These increases were partially offset by a $7 million decrease in purchased power as a result of increased generation and a $7 million decrease in amortization of water supply contracts established under Texas Genco purchase accounting which ended in 2007.

- o *Northeast* — increased by $46 million due to $20 million higher natural gas costs, $17 million in increased coal costs and $9 million in greater oil costs. The higher coal costs are the result of increased generation and transportation expenses associated with fuel surcharges. Natural gas cost rose due to higher prices and oil costs increased as a result of greater oil-fired generation at the Norwalk and Oswego plants.

- o *South Central* — increased by $11 million due to a $8 million increase in purchased energy reflecting higher gas costs, a $3 million increase primarily due to a rise in point-to-point transmission costs driven by higher merchant energy sale, and a $2 million increase in coals costs resulting primarily from higher fuel transportation surcharges. These increases were partially offset by a $2 million decrease in natural gas costs due to lower generation from gas plants.

- o *West* — increased by $12 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 by $6 million during the three months ended June 30, 2008 compared to the same period in 2007. This decrease was due to:

  - o *Northeast* — decreased by $11 million due to a $7 million decrease in operating and maintenance expenses resulting from less outage work at the Huntley, Montville and Norwalk plants and a $4 million decrease in property taxes due to the recognition of credits against the property tax at the Western New York plants.

  - o *Texas* — increased by $7 million due to an increase in operating and maintenance expenses and an increase in property taxes. These increases are the result of higher equipment retirements and refueling outages at the STP plant and higher tax assessments at the STP and Limestone facilities.

General and Administrative Costs

NRG's general and administrative, or G&A, costs increased by $12 million for the three months ended June 30, 2008 compared to the same period in 2007 due to higher wage and benefit costs.

Development Costs

NRG's development costs arise from *Repowering*NRG projects and were $4 million for the three months ended June 30, 2008 which is a decrease of $32 million when compared to the same period in 2007:

- *Texas STP units 3 and 4 projects* — the Company recorded $8 million of income during the second quarter 2008, compared to $23 million in development expenses during the same period 2007. The 2008 activity reflects an April 2008 reimbursement under a partnership agreement of development costs incurred in 2007. No development expense was reflected in results of operations for the second 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.

- *Wind projects* — the Company incurred $3 million in development costs related to Texas wind projects, 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 (Losses)/Earnings of Unconsolidated Affiliates

NRG's equity (losses)/earnings from unconsolidated affiliates decreased by $27 million for the three months ended June 30, 2008 compared to the same period in 2007. This decrease was due to a $32 million mark-to-market unrealized loss on a forward contract for natural gas swap executed to hedge the future power generation from the Sherbino I Wind Farm equity investment.

Other Income, Net

NRG's other income decreased by $3 million for the three months ended June 30, 2008 compared to the same period in 2007. This decrease is primarily due to reduced interest income of $4 million from lower market interest rates on cash deposits.

Refinancing Expense

Refinancing expense decreased by $35 million for the three months ended June 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 $30 million for the three months ended June 30, 2008 compared to the same period in 2007. This decrease is 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 (Benefit)/Expense

NRG's income tax expense decreased by $153 million for the three months June 30, 2008 compared to the same period in 2007. The effective tax rate was 57.6% and 41.2% for the three months ended June 30, 2008 and 2007, respectively. The decrease in income tax expense was primarily due to a decrease in income.

(In millions except percentages) **Three months Ended June 30,**	**2008**	**2007**
(Loss)/income from continuing operations before income taxes	$ (92)	$ 243
Tax at 35%	(32)	85
State taxes, net of federal benefit	(7)	10
Foreign operations	(5)	—
Valuation allowance	(9)	1
Foreign dividends	(1)	2
Non-deductible interest	2	3
Other permanent differences	(1)	(1)
Income tax (benefit)/expense	$ (53)	$ 100
Effective income tax rate	57.6%	41.2%

The decrease in income tax expense was due to:

- *Decrease in income* — income before tax decreased by $335 million with a corresponding decrease of $132 million in income tax expense.
- *Permanent differences* — the Company's effective tax rate differed from the US statutory rate of 35% due to:
  - o *Capital loss position* — during the first quarter 2008, the Company generated net capital losses due to derivative trading activity for which the Company determined the need for a valuation allowance. However, during the second quarter 2008,

the Company generated overall net capital gains. As result of this net capital gain, the valuation allowance established in the first quarter 2008 was no longer required. This decrease in valuation allowance includes $9 million of federal tax expense and $1 million of state and local tax expense. The Company reduced its foreign valuation allowance by $1 million due to the utilization of foreign NOLs.

- o *Lower tax rates in foreign jurisdictions* — lower income tax rates at the Company's foreign locations resulted in an income tax benefit during the second quarter 2008 as compared to the same period in 2007 of $5 million.

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 June 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 three months ended June 30, 2008 and 2007, NRG recorded income from discontinued operations, net of income tax expense, of $168 million and $6 million, respectively. NRG closed the sale of ITISA during the second quarter 2008, and recognized a pre-tax gain of $270 million from the sale, including an estimated purchase price adjustment of $9 million.

Management's discussion of the results of operations for the six months ended June 30, 2008 and 2007:

Operating Revenues

Operating revenues decreased by $217 million during the six months ended June 30, 2008 compared to the same period in 2007.

- *Energy revenues* —increased by $307 million during the six months ended June 30, 2008 compared to the same period in 2007:
  - o *Texas* — increased by $221 million due to a $135 million increase in generation and an $86 million increase in price. The increase in generation was driven by 12% higher generation from gas plants, 2% higher generation from coal plants, and 4% higher generation from the nuclear plant. The increase in price resulted from higher merchant prices of $35 per MWh partially offset by a $6 per MWh reduction in contracted energy prices.
  - o *Northeast* — increased by $23 million due to increased energy prices of $45 million and higher generation of $11 million, or a net 2% increase in generation. These increases were partially offset by a $33 million reduction in contracted energy revenues driven by higher costs incurred to service PJM contracts.
  - o *South Central* — increased by $42 million due to $33 million higher merchant energy revenues and $7 million of improved contract energy revenues. The growth in merchant energy revenues reflects an 8% rise in coal generation. Merchant energy MWh sold increased 45% while contracted MWh sold decreased by 1%. The increase in contracted energy revenues was driven by higher fuel cost pass-through adjustments for the region's cooperative customers.
  - o *West* — increased by $12 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 by $119 million during the six months ended June 30, 2008 compared to the same period in 2007:
  - o *Texas* — increased by $54 million due to a greater proportion of base-load contracts which contain a capacity component.
  - o *Northeast* — increased by $35 million due to $25 million in additional revenues from PJM assets reflecting recognition of a full six months' revenue from the RPM capacity market and a $10 million increase in NEPOOL assets driven by additional revenue recognized on the Norwalk RMR contract. NYISO capacity revenues were consistent with 2007 as

favorable capacity contract prices offset declines in prices driven by both the NYISO's reductions in Installed Reserve Margin as well as lower capacity prices in New York City.

- *South Central* — increased by $8 million due to $9 million in higher capacity payments from the region's cooperative customers resulting from new peak loads and increased merchant capacity from the Rockford plants which earn RPM capacity revenue from the PJM Market. The increases were offset by a $2 million decrease of capacity payments from other contract customers.

- *West* — increased by $14 million from a new tolling arrangement at Long Beach plant.

- *Contract amortization revenues* — increased by $38 million during the six months ended June 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 purchase accounting of Texas Genco.

- *Other revenues* — increased by $56 million during the six months ended June 30, 2008 compared to the same period in 2007. The increases arose from greater ancillary services revenue of $18 million, increased activity in the trading of emission allowances and carbon financial instruments of $17 million, and $19 million in higher activity from the trading of gas and coal.

- *Risk management activities* — revenues from risk management activities include all derivative activity that does not qualify for hedge accounting and the ineffective portion associated with hedged transactions. Such revenues decreased by $726 million during the six months ended June 30, 2008 compared to the same period in 2007. The breakdown of changes by region is as follows:

	Six months ended June 30, 2008				Six months ended June 30 2007			
(In millions)	**Texas**	**Northeast**	**South Central**	**Total**	**Texas**	**Northeast**	**South Central**	**Total**
Net gains/(losses) on settled positions, or *financial revenues*	$ (50)	$ (24)	$ —	$ (74)	$ 16	$ 36	$ 4	$ 56
Mark-to-market results								
Reversal of previously recognized unrealized gains on settled positions related to economic hedges	(16)	(9)	—	(25)	(54)	(38)	—	(92)
Reversal of previously recognized unrealized (gains)/losses on settled positions related to trading activity	1	(2)	(11)	(12)	1	(12)	(10)	(21)
Net unrealized gains/(losses) on open positions related to economic hedges	(495)	(142)	—	(637)	38	6	—	44
Net unrealized gains/(losses) on open positions related to trading activity	37	(7)	1	31	5	3	14	22
Subtotal mark-to-market results	(473)	(160)	(10)	(643)	(10)	(41)	4	(47)
Total gain/(loss)	$ (523)	$ (184)	$ (10)	$ (717)	$ 6	$ (5)	$ 8	$ 9

NRG's second quarter 2008 loss is comprised of $643 million of mark-to-market losses and $74 million in settled losses, or financial revenue. Of the $643 million of mark-to-market losses, $25 million represents the reversal of mark-to-market gains recognized on economic hedges and $12 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 $637 million loss from economic hedge positions included a $259 million decrease in value of forward sales of electricity and fuel due to higher power and gas prices and a $378 million loss primarily from hedge accounting ineffectiveness related to gas trades in the Texas region which was driven by increasing gas prices while power prices rose at a slower pace.

Since these hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, 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. These changes are recorded net of both financial instruments hedges that are afforded hedge accounting treatment and cost of energy. 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 increased, resulting in the recognition of unrealized mark-to-market forward losses. In 2007, NRG recognized forward mark-to-market losses as forward prices of electricity increased relative to its forward positions.

Cost of Operations

Cost of operations increased by $194 million during the six months ended June 30, 2008 compared to the same period in 2007.

- *Cost of energy* — increased by $215 million during the six months ended June 30, 2008 compared to the same period in 2007 due to:
  - *Texas* — increased by $124 million due to a $114 million rise in natural gas costs, a $21 million increase in coal costs, a $12 million rise in ancillary services costs, and a $4 million increase in nuclear fuel expense. The rise in natural gas cost caused by a $2.67 per MMBtu rise in average gas prices. The increase in coal costs was a result of the recognition of a settlement related to a coal contract dispute and higher coal prices. The increase in nuclear fuel expense was due to higher generation. Additionally, the increase in ancillary services and other costs were the result of higher purchased ancillary services and increased ERCOT ISO fees. These increases were partially offset by a $24 million decrease of amortization of water supply contracts established under Texas Genco purchase accounting which ended in 2007 and a $3 million decrease in purchased power due to greater generation.
  - *Northeast* — increased by $52 million due to a $39 million increase in coal costs and a $34 million increase in natural gas costs. Coal costs increased as a result of a 8% rise in coal generation and an increase in transportation cost driven by fuel surcharges. Natural gas costs increased due to higher natural gas prices. These increases were offset by a $21 million reduction in oil costs reflecting lower oil-fired generation at the Middletown and Oswego plants.
  - *South Central* — increased by $18 million due to an $8 million rise in coals costs resulting from an 8% increase in generation and transportation cost, a $6 million rise in transmission costs, and a $4 million increase in purchased energy.
  - *West* — increased by $13 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 by $21 million during the six months ended June 30, 2008 compared to the same period in 2007. This decrease was due to:
  - *Texas* — increased $6 million in operating and maintenance expenses due to increased outage time at the STP plant.
  - *Northeast* — decreased by $19 million due to a $14 million decrease in operating and maintenance expenses and $5 million decrease in property taxes. The decrease in operating and maintenance expenses was the result of less outage work and higher reliability at the Arthur Kill, Huntley and Norwalk plants. The decrease in property taxes was caused by the recognition of credits against the property tax at the Western New York plants.
  - *South Central* — decreased by $5 million due to increased maintenance expense resulting from more extensive spring outage work performed at the Big Cajun II plant in 2007 than in 2008.

General and Administrative Costs

NRG's G&A costs increased by $2 million for the six months ended June 30, 2008 compared to the same period in 2007.

- Wage and benefits costs — increased by $12 million due to increased benefit accruals.

This increase was partially offset by:

- *Franchise tax expense* — decreased by $6 million due to Louisiana franchise tax expense. Louisiana franchise tax expense is assessed based on the Company's total debt and equity that significantly increased following the Acquisition whereby a retroactive adjustment to franchise tax expense was recorded in 2007.

- *Other G&A expenses* — decreased by $4 million due to reductions in insurance expense and relocation expense.

Development Costs

NRG's development costs that rose from *Repowering*NRG projects, were $16 million for the six months ended June 30, 2008 which is a decrease of $43 million when compared to the same period in 2007:

- *Texas STP units 3 and 4 projects* — the Company recorded $8 million of income during the six months ended June 30, 2008, compared to $39 million in development expenses during the second period 2007. The 2008 activity reflects an April 2008 reimbursement under a partnership agreement of development costs incurred in 2007. No development expense is reflected in results of operations for the six months ended June 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 $9 million in development costs related to Texas wind projects which is a $3 million increase from the same period in 2007.

- *Other projects* — the Company incurred $15 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 first six months of 2008. For the six months ended June 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 (Losses)/Earnings of Unconsolidated Affiliates

NRG's equity (losses)/earnings from unconsolidated affiliates decreased by $44 million for the six months ended June 30, 2008 compared to the same period in 2007. This decrease was due to a $49 million mark-to-market unrealized loss on natural gas swap executed to hedge the future power generation from the Sherbino I Wind Farm equity investment.

Other Income, Net

NRG's other income decreased by $9 million for the six months ended June 30, 2008 compared to the same period in 2007. This decrease was primarily due to reduced interest income of $8 million from lower market interest rates on cash deposits.

Refinancing Expense

Refinancing expense decreased by $35 million for the six months ended June 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 $56 million for the six months ended June 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.

Income Tax Expense

NRG's income tax expense decreased by $154 million for the six months ended June 30, 2008 compared to the same period in 2007. The effective tax rate was 10.0% and 43.2% for the six months ended June 30, 2008 and 2007, respectively. The decrease in income tax expense was primarily due to a decrease in income.

(In millions except percentages) **Six months Ended June 30,**	**2008**	**2007**
Income from continuing operations before income taxes	$ 10	$ 359
Tax at 35%	4	126
State taxes, net of federal benefit	(1)	16
Foreign operations	(8)	(1)
Valuation allowance	(1)	1
Foreign dividends	5	8
Non-deductible interest	5	5
Other permanent differences	(3)	—
Income tax expense	$ 1	$ 155
Effective income tax rate	10.0%	43.2%

The decrease in income tax expense was due to:

- *Decrease in income* — income before tax decreased by $349 million, with a corresponding decrease of $138 million in income tax expense.
- *Permanent differences* — the Company's effective tax rate differs from the US statutory rate of 35% due to:
  - o *Lower tax rates in foreign jurisdictions* — lower income tax rates at the Company's foreign locations resulted in additional income tax benefit during the first six months of 2008 compared to the same period in 2007 of $7 million.
  - o *Taxable dividends from foreign subsidiaries* — in January 2007, the Company transferred the proceeds from the sale of its Flinders assets to the U.S. creating an additional income tax benefit of approximately $3 million in 2008 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 six months ended June 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 six months ended June 30, 2008 and the same period in 2007, NRG recorded income from discontinued operations, net of income tax expense, of $172 million and $10 million, respectively. NRG closed the sale of ITISA during the second quarter 2008, and recognized a pre-tax gain of $270 million from the sale, including an estimated purchase price adjustment of $9 million.

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 June 30,			Six months ended June 30,		
(In millions except otherwise noted)	**2008**	**2007**	**Change %**	**2008**	**2007**	**Change %**
Operating Revenues						
Energy revenue	$ 925	$ 687	35%	$ 1,471	$ 1,250	18%
Capacity revenue	119	91	31	237	183	30
Risk management activities	(419)	26	N/A	(523)	6	N/A
Contract amortization	83	61	36	146	108	35
Other revenues	43	10	330	69	23	200
Total operating revenues	751	875	(14)	1,400	1,570	(11)
Operating Costs and Expenses						
Cost of energy	413	310	33	671	547	23
Other operating expenses	150	167	(10)	314	352	(11)
Depreciation and amortization	113	114	(1)	226	228	(1)
Operating Income	$ 75	$ 284	(74)	$ 189	$ 443	(57)
MWh sold (in thousands)	12,675	12,265	3	23,706	23,245	2
MWh generated (in thousands)	12,500	11,994	4	23,256	22,737	2
Business Metrics						
Average on-peak market power prices ($/MWh)	164.29	70.87	132	117.80	64.18	84
Cooling Degree Days, or CDDs (a)	1,009	803	26	1,092	955	14
CDD's 30 year average	854	854	—	949	949	—
Heating Degree Days, or HDDs (a)	112	146	(23)%	1,157	1,284	(10)%
HDD's 30 year average	83	83	—	1,215	1,215	—

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

Quarterly Results

Operating Income

Operating income decreased by $209 million for the three months ended June 30, 2008, compared to the same period in 2007, primarily due to:

- *Energy revenues* — increased by $238 million due to higher merchant energy revenue as a result of increased market prices and sales volumes offset by lower contract energy revenue caused by a reduction in contract prices.

- *Risk management activities* — a decrease of $445 million was primarily due to $399 million in greater unrealized derivative losses and $46 million in lower gains on settled financial transactions. These increases in realized and unrealized losses reflect a trend towards rising power and gas prices evident in the second quarter 2008.

- *Cost of energy* — increased by $103 million reflecting the effects of increased natural gas prices in 2008.

Operating Revenues

Total operating revenues decreased by $124 million during the three months ended June 30, 2008, compared to the same period in 2007, due to:

- *Risk management activities* — losses of $419 million were recognized for the three months ended June 30, 2008 compared to a $26 million gains in the same period in 2007. The $419 million includes $371 million of unrealized mark-to-market losses and $48 million in settled losses, or financial revenue, compared to $28 million in unrealized derivative gains and $2 million of settled financial losses in the same period in 2007. The $371 million is the net effect of a $382 million loss from economic hedge positions and reversals of $9 million of mark-to-market gains on economic hedges, partially offset by $20 million in unrealized mark-to-market gains on trading transactions. The $382 million loss from economic hedges incorporates $68 million in unrealized losses 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 $314 million in losses are from hedge ineffectiveness which was driven by increasing gas prices while power prices rose at a slower pace.

This decrease was partially offset by:

- *Energy revenues* — increased by $238 million due to:
  - Generation — increased by $131 million caused by a 24% rise in gas plant generation due to higher margins for merchant generation and a 2% increase in coal plant generation.
  - Energy prices — increased by $107 million on the same volume year over year that contained a mix of higher merchant generation and less contract generation due to increased merchant prices of $52 per MWh partially offset by a reduction in contracted energy prices of $7 per MWh. Increased merchant prices were driven by higher natural gas prices and higher heat rates in the ERCOT Houston zone.
- *Capacity revenue* — increased by $28 million due to a greater proportion of base-load contracts which contain a capacity component.
- *Contract amortization* — increased by $22 million due to the volume of contracted energy affected by a greater spread between contract and market prices used in the Texas Genco accounting.
- *Other revenues* — increased by $33 million related to greater ancillary revenue of $14 million, increased trading of emission allowances and carbon financial instruments of $13 million, and increased activity in trading natural gas and coal of $5 million.

Cost of Energy

Cost of energy increased by $103 million during the three months ended June 30, 2008, compared to the same period in 2007, due to:

- *Natural gas costs* — increased by $104 million due to a $3.75 per MMBtu rise in average natural gas prices, along with a 24%, or 329 thousand MWh, increase in gas-fired generation.
- *Ancillary services and miscellaneous other costs* — increased by $6 million due to a $4 million increase in purchased ancillary services costs incurred to meet contract obligations and a $2 million increase in ERCOT ISO fees that became effective in June 2007 related to the development of the nodal market.
- *Coal costs* — increased by $5 million, due to the 2% increase, or 159 thousand MWh, in coal-fired generation.
- *Nuclear fuel expense* — increased by $2 million due to a 1%, or 16 thousand MWh, increase in generation.

These increases were partially offset by:

- *Purchased power* — decreased by $7 million due to increased generation by the region's fleet driven by higher merchant prices and lower outage rates at the region's baseload plants.

- *Amortized contract costs* — decreased by $7 million due to amortization of water supply contracts established under Texas Genco purchase accounting which ended in 2007.

Other Operating Expenses

Other operating expenses decreased by $17 million during the three months ended June 30, 2008, compared to the same period in 2007, due to:

- *Development costs* —decreased by $29 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. STP development costs are being capitalized in 2008.

This decrease was offset by:

- *Operations & maintenance expense* —increased by $4 million due to STP equipment retirements and refueling outage.

- *G&A Expense* — increased by $5 million due to higher corporate allocations in 2008 compared to 2007.

- *Property taxes* — increased by $3 million due to higher tax estimates in 2008 than in 2007 at the STP and Limestone plants.

Year-to-date Results

Operating Income

Operating income decreased by $254 million for the six months ended June 30, 2008, compared to the same period in 2007, primarily due to:

- *Energy revenues* — increased by $221 million due to higher merchant energy revenue as a result of increased market prices and sales volumes offset by lower contract energy revenue caused by a reduction in contract prices.

- *Risk management activities* — a decrease of $529 million was primarily due to $463 million in greater unrealized derivative losses and $66 million in lower gains on settled financial transactions. These increases in realized and unrealized losses reflect a trend towards rising power and gas prices evident in the six months ended June 30, 2008.

- *Cost of energy* — increased by $124 million reflecting the effects of increased natural gas prices and settlement of a coal contract dispute in 2008.

Operating Revenues

Total operating revenues decreased by $170 million during the six months ended June 30, 2008, compared to 2007, due to:

- *Risk management activities* — losses of $523 million were recognized for the six months ended June 30, 2008 compared to a $6 million gain in the same period in 2007. The $523 million includes $473 million of unrealized mark-to-market losses and $50 million in settled losses, or financial revenue, compared to $10 million in unrealized derivative losses and $16 million of settled financial gains in the same period in 2007. The $473 million is the net effect of a $495 million loss from economic hedge positions, the reversal of $16 million of mark-to-market gains on economic hedges and the reversal of $1 million of mark-to-market losses on trading activity, partially offset by $37 million in unrealized mark-to-market gains on trading transactions. The $495 million loss from economic hedges incorporates $137 million in unrealized losses 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 $358 million in losses are from hedge ineffectiveness which was driven by increasing gas prices while power prices rose at a slower pace.

This decrease was partially offset by:

- *Energy revenues* — increased by $221 million due to:
  - o Generation — increased by $135 million caused by a 12% increase in gas generation over 2007 due to higher margins for merchant generation and 4% higher nuclear generation at STP.
  - o Energy prices — increased by $86 million on the same volume year over year that contained a mix of higher merchant generation and less contract generation due to higher merchant prices of $35 per MWh partially offset by a $6 per MWh reduction in contracted energy prices. Increased merchant prices were driven by higher natural gas prices and higher heat rates in the ERCOT Houston zone.
- *Capacity revenue* — increased by $54 million due to a greater proportion of base-load contracts which contain a capacity component.
- *Contract amortization* — increased by $38 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.
- *Other revenues* — increased by $46 million related to increased trading of emission allowances and carbon financial instruments of $23 million, greater ancillary revenue of $13 million, and increased activity in trading natural gas and coal of $11 million.

Cost of Energy

Cost of energy increased by $124 million during the six months ended June 30, 2008, compared to the same period in 2007, due to:

- *Natural gas costs* — increased by $114 million due to a $2.67 per MMBtu rise in average gas prices, along with a 12%, or 258 thousand MWh, increase in gas-fired generation.
- *Coal costs* — increased by $21 million due to the settlement of a coal contract dispute and higher coal prices.
- *Ancillary services and miscellaneous other costs* — increased by $12 million due to a $8 million increase in purchased ancillary services costs incurred to meet contract obligations and a $4 million increase in ERCOT ISO fees that became effective in June 2007 related to the development of the nodal market.
- *Nuclear fuel expense* — increased by $4 million due to a 4%, or 197 thousand MWh, increase in generation.

These increases were partially offset by:

- *Amortized contract costs* — decreased by $24 million due to amortization of water supply contracts established under Texas Genco purchase accounting which ended in 2007.
- *Purchased power* — decreased by $3 million due to increased generation by the region's fleet driven by higher merchant prices and lower outage rates at the region's baseload plants.

Other Operating Expenses

Other operating expenses decreased by $38 million during the six months ended June 30, 2008, compared to 2007, due to:

- *Development costs* — decreased by $46 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. STP development costs are being capitalized in 2008.

This decrease was primarily offset by:

- *Operations & maintenance expense* — increased by $6 million, related to STP equipment retirements and refueling outage and the timing of annual outages at the WA Parish and Limestone plants.

- *G&A expense* — increased by $3 million due to higher corporate allocations in 2008 compared to 2007.

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 June 30,			Six months ended June 30,		
(In millions except otherwise noted)	2008	2007	Change %	2008	2007	Change %
Operating Revenues						
Energy revenue	$ 285	$ 254	12%	$ 549	$ 526	4%
Capacity revenue	101	93	9	211	176	20
Risk management activities	(146)	24	N/A	(184)	(5)	N/A
Other revenues	25	24	4	49	40	23
Total operating revenues	265	395	(33)	625	737	(15)
Operating Costs and Expenses						
Cost of energy	191	145	32	359	307	17
Other operating expenses	91	103	(12)	184	206	(11)
Depreciation and amortization	25	24	4	51	49	4
Operating (Loss)/Income	$ (42)	$ 123	N/A	$ 31	$ 175	(82)
MWh sold (in thousands)(b)	3,245	3,073	6	6,836	6,696	2
MWh generated (in thousands)	3,245	3,073	6	6,886	6,696	3
Business Metrics						
Average on-peak market power prices ($/MWh)	107.36	75.50	42	96.76	74.70	30
Cooling Degree Days, or CDDs(a)	165	161	2	165	161	2
CDD's 30 year average	105	105	—	105	105	—
Heating Degree Days, or HDDs(a)	771	847	(9)%	3,731	3,994	(7)%
HDD's 30 year average	841	841	—	3,968	3,968	—

(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 PJM marketplace.*

Quarterly Results

Operating Income

Operating income decreased by $165 million for the three months ended June 30, 2008, compared to the same period in 2007, primarily due to:

- *Operating revenues* — decreased by $130 million due to the unfavorable impact of risk management activities, partially offset by favorable energy revenue and capacity revenue.

- *Cost of energy* — increased by $46 million due to a 6% increase in generation, higher coal transportation costs across the region and increased coal commodity costs at the Somerset plant.

Operating Revenues

Operating revenues decreased by $130 million for the three months ended June 30, 2008, compared to the same period in 2007, due to:

- *Risk management activities* — losses of $146 million were recorded for the three months ending June 30, 2008, compared to gains of $24 million during the same period in 2007. The $146 million loss includes $112 million of unrealized mark-to-market losses and $34 million in losses on settled transactions, or financial revenue, compared to $17 million in unrealized mark-to-market gains and $7 million in financial revenue gains during the same period in 2007. The $112 million unrealized loss is the net effect of a $113 million loss from economic hedge positions, the reversal of $6 million of mark-to-market gains on economic hedges and the reversal of $3 million of mark-to-market gains on trading activity, partially offset by $10 million in unrealized mark-to-market gains on trading activity. Losses are primarily driven by increases in power and gas prices.

This loss was partially offset by:

- *Energy revenues* — increased by $31 million due to:

  - *Energy prices* — increased by $36 million reflecting an average 15% rise in energy prices.

  - *Generation* — increased by $16 million due to a net 6% increase in generation. The increase in generation represents a 212 thousand MWh, or 9%, increase in base-load coal generation as a result of the timing of outages at the Huntley and Indian River plants and higher reliability at the Huntley plant. Additionally, oil-fired generation increased by 41 thousand MWh, or 27%, due to additional generation at the Norwalk plant, which was called upon by ISO-NE for reliability reasons.

  These increases were offset by:

  - *Contracted energy* — decreased by $18 million driven by higher costs required to service the PJM contracts, as a result of the increase in market energy prices.

- *Capacity revenues* — increased by $8 million due to:

  - *PJM* — capacity revenues increased by $10 million reflecting recognition of a full quarter's revenue from the RPM capacity market (effective on June 1, 2007).

  - *NEPOOL* — capacity revenues increased by $2 million from additional revenue recognized on the Norwalk RMR contract (effective on June 19, 2007).

  These increases were partially offset by:

  - *NYISO* — capacity revenues decreased by $4 million due to unfavorable prices. The lower capacity market prices are a result of NYISO's reductions in Installed Reserve Margins as well as lower capacity prices in New York City driven by competitor bidding strategies.

Cost of Energy

Cost of energy increased by $46 million for the three months ended June 30, 2008, compared to the same period in 2007, due to:

- *Natural gas costs* — increased by $20 million due to higher natural gas prices.

- *Coal costs* — increased by $17 million, or 26%, due to a 9% increase in coal generation, higher transportation expenses driven by fuel surcharges and greater commodity costs at the Somerset plant.

- *Oil costs* — increased by $9 million as a result of higher oil-fired generation at the Norwalk and Oswego plants.

Other Operating Expenses

Other operating expenses decreased by $12 million for the three months ended June 31, 2008, compared to the same period in 2007, due to:

- *Major maintenance expenses* — decreased by $7 million due to less outage work at the Huntley, Montville and Norwalk plants.
- *Property taxes* — decreased by $4 million due primarily to the recognition of credits against the property tax at the Western New York plants.

Yearly Results

Operating Income

Operating income decreased by $144 million for the six months ended June 30, 2008, compared to the same period in 2007, primarily due to:

- *Operating revenues* — decreased by $112 million due to losses in the region's risk management activities, partially offset by favorable energy revenue, capacity revenue and emission revenue.
- *Cost of energy* — increased by $52 million due to higher coal generation, increased coal transportation costs, and higher coal natural gas prices partially offset by lower oil costs as a result of lower oil-fired generation due to a colder winter in 2007.

Operating Revenues

Operating revenues decreased by $112 million for the six months ended June 30, 2008, compared to the same period in 2007, due to:

- *Risk management activities* — losses of $184 million were recorded for the six months ending June 30, 2008, compared to losses of $5 million during the same period in 2007. The $184 million loss includes $160 million of unrealized mark-to-market losses and $24 million of losses in settled transactions, or financial revenue, compared to $41 million in unrealized mark-to-market losses and $36 million in financial revenue gains during the same period in 2007. The $160 million unrealized loss is the net effect of a $142 million loss from economic hedge positions, the reversal of $9 million of mark-to-market gains on economic hedges, the reversal of $2 million of mark-to-market gains on trading activity and $7 million in unrealized mark-to-market losses on trading activity. Unrealized losses are primarily driven by increases in power and gas prices.

These losses were partially offset by:

- *Energy revenues* — increased by $23 million due to:
  - *Energy prices* — increased by $45 million reflecting an average 9% rise in energy prices.
  - *Generation* — increased by $11 million due to a net 2% increase in generation. The increase in generation represents a 461 thousand MWh, or 8%, increase in base-load coal generation as a result of the timing of outages at the Huntley and Indian River plants and higher reliability at the Huntley plant. This increase was partially offset by a 312 thousand MWh, or 51%, decrease in oil-fired generation due mainly to less generation at the Oswego and Middletown plants, as a result of a colder winter in 2007.

These increases were partially offset by:

  - *Contracted energy* — decreased by $33 million driven by higher costs incurred to service the PJM contracts as a result of the increase in market energy prices.

- *Capacity revenues* — increased by $35 million due to:
  - o *PJM* — capacity revenues increased by $25 million reflecting recognition of six months of revenue from the RPM capacity market (effective on June 1, 2007) in 2008 compared to one month in 2007.
  - o *NEPOOL* — capacity revenues increased by $10 million from additional revenue recognized on the Norwalk RMR contract (effective on June 19, 2007).
  - o *NYISO* — capacity revenues were consistent with 2007. Favorable capacity contract prices offset a decline in prices driven by both the NYISO's reductions in Installed Reserve Margins as well as lower capacity prices in New York City driven by competitor bidding strategies.
- *Other revenues* — increased by $9 million due to the increased activity of the trading of emission allowances.

Cost of Energy

Cost of energy increased by $52 million for the six months ended June 30, 2008, compared to the same period in 2007, due to:

- *Coal costs* — increased by $39 million, or 27%, due to an 8% increase in coal generation, higher transportation expenses driven by fuel surcharges and greater commodity costs at the Somerset plant.
- *Natural gas costs* — increased by $34 million due to higher natural gas prices.

These increases were partially offset by:

- *Oil costs* — decreased by $21 million primarily as a result of lower oil-fired generation at the Middletown and Oswego plants, as a result of a colder winter in 2007.

Other Operating Expenses

Other operating expenses decreased by $22 million for six months ended June 30, 2008, compared to the same period in 2007, primarily due to:

- *Major maintenance expenses* — decreased by $14 million due to less outage work and higher reliability at the Arthur Kill, Huntley and Norwalk plants.
- *Property taxes* — decreased by $5 million due to the recognition of credits against the property tax at the Western New York plants.

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

(In millions except otherwise noted)	Three months ended June 30, 2008	Three months ended June 30, 2007	Change %	Six months ended June 30, 2008	Six months ended June 30, 2007	Change %
Operating Revenues						
Energy revenue	$ 130	$ 101	29%	$ 230	$ 188	22%
Capacity revenue	58	55	5	115	107	7
Risk management activities	(23)	2	N/A	(10)	8	N/A
Contract amortization	5	6	(17)	11	11	—
Other revenues	2	—	N/A	5	—	N/A
Total operating revenues	172	164	5	351	314	12
Operating Costs and Expenses						
Cost of energy	116	105	10	204	186	10
Other operating expenses	33	32	3	55	62	(11)
Depreciation and amortization	17	17	—	34	34	—
Operating Income	$ 6	$ 10	(40)	$ 58	$ 32	81
MWh sold (in thousands)	3,017	3,004	—	6,105	5,831	5
MWh generated (in thousands)	2,576	2,516	2	5,600	5,224	7
Business Metrics						
Average on-peak market power prices ($/MWh)	84.82	64.13	32	76.28	60.99	25
Cooling Degree Days, or CDDs(a)	546	577	(5)%	550	604	(9)
CDD's 30 year average	458	458	—	489	489	—
Heating Degree Days, or HDDs(a)	319	319	—	2,223	2,081	7%
HDD's 30 year average	299	299	—	2,213	2,213	—

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

Quarterly Results

Operating Income

Operating income decreased by $4 million for the three months ended June 30, 2008, compared to the same period in 2007, primarily due to:

- *Cost of energy* — increased by $11 million due to higher purchased energy, transmission costs, and coal transportation costs.
- *Operating revenues* — increased by $8 million due to the increase in energy revenue and capacity revenue offset by an unfavorable impact of risk management activities.

Operating Revenues

Operating revenues increased by $8 million for the three months ended June 30, 2008, compared to the same period in 2007, due to:

- *Energy revenues* — increased by $29 million due to $25 million in higher merchant energy revenues and $3 million of improved contract energy revenues. The growth in merchant energy revenues reflects a 5% rise in coal generation driven by fewer outage hours. The increase in contracted energy revenues is driven by higher fuel cost pass-through adjustments for the region's cooperative customers. Merchant energy MWh sold increased by 16% while contract MWh sold decreased by 3%.

The decrease in contract MWh sold represents a 140 thousand MWh, or 23%, decrease in MWh sold to other contract customers offset by a 67 thousand MWh, or 3%, increase in MWh sold to cooperative customers.

- *Capacity revenues* — increased by $3 million due to new peak loads set by the region's cooperative customers which resulted in $4 million of additional capacity payments offset by a $1 million decrease in capacity payments from other contract customers.

- *Other revenues* — increased by $2 million due to increased activity in trading natural gas and coal.

These increases were offset by:

- *Risk Management Activities* — losses of $23 million were recognized during the second quarter 2008 compared to gains of $2 million recognized during the same period in 2007. The $23 million loss includes $19 million in unrealized losses and $4 million in realized losses on settled transactions; compared to $2 million in unrealized losses offset by $4 million in realized gains for the same period in 2007. The $19 million unrealized loss is the net effect of a $15 million unrealized mark-to-market loss from trading activity and the reversal of $4 million of mark-to-market gains on trading activity. Unrealized losses are primarily driven by increases in power and gas prices.

Cost of Energy

Cost of energy increased by $11 million for the three months ended June 30, 2008, compared to the same period in 2007, due to:

- *Purchased energy* — increased by $8 million reflecting higher gas costs associated with the region's tolling agreements.

- *Transmission costs* — increased by $3 million due to $2 million in higher point-to-point transmission costs driven by an increase in merchant energy sales and $1 million in additional network transmission costs that are passed through to the region's cooperative customers.

- *Coal costs* — increased by $2 million due to a $3 million rise in coal unit costs due to increases in fuel transportation surcharges, offset by a $1 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.

These increases were offset by:

- *Natural gas costs* — decreased by $2 million due to lower generation from the region's gas-fired plants.

Yearly Results

Operating Income

Operating income increased by $26 million for the six months ended June 30, 2008, compared to the same period in 2007 due to:

- *Operating revenues* — increased by $37 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 $18 million due to higher purchased energy, transmission costs and coal transportation costs.

Operating Revenues

Operating revenues increased by $37 million for the six months ended June 30, 2008, compared to the same period in 2007, due to:

- *Energy revenues* — increased by $42 million due to $33 million in higher merchant energy revenues and $7 million of improved contract energy revenues. The growth in merchant energy revenues reflects an 8% rise in coal generation driven by fewer outage hours. The increase in contracted energy revenue is driven by higher fuel cost pass-through adjustments for the region's cooperative customers. Merchant energy MWh sold increased by 45% while contract MWh sold decreased by 1%. The decrease in contract MWh sold represents a 179 thousand MWh, or 17%, decrease in MWh sold to other contract customers offset by a 130 thousand MWh, or 3%, increase in MWh sold to cooperative customers.

- *Capacity revenues* — increased by $8 million due to new peak loads set by the region's cooperative customers which resulted in $9 million of additional capacity payments and increased RPM capacity payments from the Rockford plants. These increases were offset by decreases of $2 million in capacity payments from other contract customers.

- *Other revenues* — increased by $5 million due to increased activity in the trading of emission allowances and higher activity in trading natural gas and coal.

These increases were offset by:

- *Risk Management Activities* — losses of $10 million were recognized during the first half of 2008 compared to $8 million in gains recognized during the same period in 2007. The $10 million loss in 2008 is all unrealized compared to a $4 million unrealized gain and $4 million realized gain in 2007. The $10 million unrealized loss is the net effect of a $1 million unrealized mark-to-market gain from trading activity offset by the reversal of $11 million of mark-to-market gains on trading activity. Unrealized losses are primarily driven by increases in power and gas prices.

Cost of Energy

Cost of energy increased by $18 million for the six months ended June 30, 2008, compared to the same period in 2007, due to:

- *Coal costs* — increased by $8 million due to a $6 million rise in costs associated with an 8% increase in coal generation and a $5 million increase in coal unit costs due to increases in fuel transportation surcharges, offset by 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 $4 million in additional point-to-point transmission costs driven by an increase in merchant energy sales and $2 million in higher network transmission costs that are passed through to the region's cooperative customers.

- *Purchased energy* — increased by $4 million reflecting a decrease in purchased MWh of 16% as increased plant availability reduced power purchases required to support contract load. The decrease was offset by a 27% increase in the average cost per MWh of purchased energy, which reflects higher gas costs associated with the region's tolling agreements.

Other Operating Expenses

Other operating expenses decreased by $7 million for the six months ended June 30, 2008, compared to the same period in 2007, due to:

- *G&A Expense* — Franchise tax decreased by $6 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 $4 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.

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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 June 30,			Six months ended June 30,		
(In millions except otherwise noted)	2008	2007	Change %	2008	2007	Change %
Operating Revenues						
Energy revenue	$ 13	$ —	N/A	$ 13	$ 1	N/A
Capacity revenue	31	29	7%	69	55	25%
Risk management activities	—	—	—	—	—	—
Other revenues	5	—	N/A	5	1	400
Total operating revenues	49	29	69	87	57	53
Operating Costs and Expenses						
Cost of energy	12	—	N/A	14	1	N/A
Other operating expenses	20	19	5	38	39	(3)
Depreciation and amortization	3	1	200	4	1	300
Operating Income	$ 14	$ 9	56	$ 31	$ 16	94
MWh sold (in thousands)	89	1	N/A	89	2	N/A
MWh generated (in thousands)	89	1	N/A	89	2	N/A
Business Metrics						
Average on-peak market power prices ($/MWh)	97.54	68.86	42	88.92	64.46	38
Cooling Degree Days, or CDDs(a)	205	135	52	205	137	50
CDD's 30 year average	150	150	—	157	157	—
Heating Degree Days, or HDDs(a)	576	450	28%	2,096	1,848	13%
HDD's 30 year average	556	556	—	1,990	1,990	—

(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 June 30, 2008, compared to the same period in 2007, due to:

- *Energy revenues* — increased by $13 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 by $2 million primarily due to a new tolling agreement at the region's Long Beach plant partially offset by the expiration of a two year tolling agreement with a load serving entity covering the El Segundo facility:
  - 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 $7 million in capacity revenues for the three months ended June 30, 2008.
  - o *El Segundo* — The expiration of the two year tolling agreement at the end of April resulted in a decrease of $3 million in capacity revenues for the three months ended June 30, 2008.
- *Other revenues* — increased by $5 million due to increased trading activity of emission allowances in 2008.

These increases were partially offset by:

- *Cost of energy* — increased by $12 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 $2 million reflecting the depreciation associated with the successful completion of the *Repowering*NRG project at the Long Beach plant.

Yearly Results

Operating Income

Operating income increased by $15 million for the six months ended June 30, 2008, compared to the same period in 2007, due to:

- *Capacity revenues* — increased by $14 million due to a new tolling agreement at the region's Long Beach plant. 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 $14 million in capacity revenues for the six months ended June 30, 2008.

- *Energy revenues* — increased by $12 million due to the 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 $1 million due to an environmental liability recognized in 2007 related to NRG's El Segundo plant.

These increases were partially offset by:

- *Cost of energy* — increased by $13 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 $3 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 June 30, 2008 and December 31, 2007, NRG's liquidity was approximately $2.6 billion and $2.7 billion, respectively, and comprised of the following:

(In millions) As of	June 30, 2008	December 31, 2007
Cash and cash equivalents	$ 1,263	$ 1,132
Restricted cash	30	29
Total cash	1,293	1,161
Synthetic letter of credit availability	327	557
Revolver credit facility availability	997	997
Total liquidity	$ 2,617	$ 2,715

For the six months ended June 30, 2008, total liquidity decreased by $98 million due to lower synthetic letter of credit availability of $230 million offset by higher cash balances of $132 million. The decrease in the synthetic letter of credit availability of $230 million is the result of the issuance of a letter of credit of $143 million to support the Company's commercial operation with marginable counterparties and $87 million to support NRG's capital contribution commitment to the Sherbino equity investment, hereinafter discussed.

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 priority liens to certain counterparties on substantially all of the Company's assets in the United States in order to secure certain obligations, which are primarily long-term in nature under certain power 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 these agreements. 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.

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.

As of June 30, 2008, and July 25, 2008, the net discounted exposure less collateral posted on the agreements and hedges that were subject to the first lien structure were approximately $2.6 billion and $688 million, respectively. As of June 30, 2008, and July 25, 2008, the net discounted exposure less collateral posted on the agreements and hedges that were subject to the second lien structure were approximately $982 million and $299 million, respectively.

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 July 25, 2008:

Equivalent Net Sales secured by First and Second Lien Structure (a)	2008(b)	2009	2010	2011	2012	2013
In MW	3,992	5,019	4,374	3,922	2,348	911
As a percentage of total forecasted baseload capacity (c)	58%	72%	64%	58%	35%	15%

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

(b) 2008 MW value consists of August 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 Extension

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 Credit Suisse 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 for any 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 the extension, the Company also contributed 795,503 additional 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 is $248 million.

ITISA

On April 28, 2008, NRG completed the sale of, and received $288 million in cash proceeds for, its 100% interest in Tosli Acquisition B.V., which holds all NRG's interest in ITISA, to Brookfield Renewable Power Inc. (previously Brookfield Power Inc.), a wholly-owned subsidiary of Brookfield Asset Management Inc., a Canadian asset management company, focused on property, power and infrastructure. The sale process removed $163 million of assets, including $59 million of cash, and $122 million of liabilities, including $63 million of debt from the discontinued assets and liabilities on the condensed consolidated balance sheet as of June 30, 2008. NRG recognized a pre-tax gain of $270 million, including an estimated purchase price adjustment of $9 million and net pre-tax cash additions of $229 million as of June 30, 2008. 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 transaction including return of capital to shareholders.

Commercial Operations

NRG's commercial operations activities require a significant amount of liquidity and capital resources. These liquidity requirements are primarily driven by: (i) margin and collateral posted with counterparties; (ii) initial collateral required to establish trading relationships; (iii) timing of disbursements and receipts (i.e., buying fuel before receiving energy revenues); and (iv) initial collateral for large structured transactions. As of June 30, 2008, commercial operations had total cash collateral outstanding of $399 million, and $693 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.

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 Repowering*NRG *Equity Investments in affiliates

For the six months ended June 30, 2008, the Company's capital expenditures, including accruals, were approximately $497 million, of which $339 million was related to *Repowering*NRG projects. The following table summarizes the Company's capital expenditures for the six months ended June 30, 2008 and the estimated capital expenditure and repowering investments forecast for the remainder of 2008.

(In millions)	Maintenance	Environmental	*Repowering*NRG	Total
Northeast	$ 10	$ 48	$ 18	$ 76
Texas	68	8	51	127
South Central	6	5	—	11
West	5	—	20	25
NINA	—	—	31	31
Wind	—	—	219	219
Other	8	—	—	8
Capital expenditures through June 30, 2008	97	61	339	497
Capital expenditures through the remainder of 2008	125	141	292	558
Total estimated capital expenditures for 2008	$ 222	$ 202	$ 631	$ 1,055
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 $131 million for wind turbines and construction related costs for the Elbow Creek wind farm project which is currently under construction and $88 million in turbine purchases for other wind projects currently under development. In addition, the Company's *Repowering*NRG capital expenditures included $51 million related to the construction of Cedar Bayou Unit 4 in Texas, $18 million for the construction of Cos Cob in Connecticut and $17 million for a deposit related to the repowering of the El Segundo generating station in the West region.

The Company's estimated repowering capital expenditures for the remainder of 2008 are expected to consist of approximately $134 million related to the construction and equipment procurement for the Elbow Creek wind farm project and certain wind farm projects under development. In addition, the Company expects to incur additional 2008 capital expenditures of approximately $41 million towards the construction of Cedar Bayou Unit 4 and $39 million towards the development of STP Units 3 and 4, and approximately $61 million for the repowering of the El Segundo generating station in California.

As subsequently discussed under *Repowering*NRG Update below, NRG expects to contribute equity of approximately $87 million to its Sherbino wind farm project and has posted a letter of credit in that amount.

Major maintenance and environmental capital expenditures — The Company's baghouse project at its Huntley and Dunkirk plants resulted in environmental capital expenditures of $37 million for the six months ended June 30, 2008. Other capital expenditures included $29 million for STP fuel and $39 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 2008 and 2009.

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	$ 23	$ 173	$ 6	$ 202
2009	—	234	1	235
2010	7	187	52	246
2011	17	154	102	273
2012	27	67	100	194
2013	32	—	67	99
Total	$ 106	$ 815	$ 328	$ 1,249

Share Repurchases

In January 2008, the Company repurchased 344,000 shares of NRG common stock for approximately $15 million under its previously announced 2008 Capital Allocation Program, thus completing $100 million in repurchases since the initiation of the program. In February 2008, the Company's Board of Directors authorized an additional $200 million in common share repurchases that raised the 2008 Capital Allocation Program to approximately $300 million. In March 2008, the Company repurchased an additional 937,600 shares of NRG common stock in the open market for approximately $40 million.

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) Six months ended June 30,	2008	2007
Net cash provided by operating activities	$ 436	$ 459
Net cash used by investing activities	(122)	(172)
Net cash used by financing activities	$ (233)	$ (291)

Net Cash Provided By Operating Activities

For the six months ended June 30, 2008, net cash provided by operating activities decreased by $23 million compared to the same period in 2007. The difference was due to:

- *Increase in generation and merchant prices* — An increase in power generation and higher merchant prices provided $206 million in cash from operations after adjusting net income for the effect of non-cash items.

- *Collateral deposits* — During the first six months of 2008, an increase in net collateral deposits of $328 million to support the Company's hedging and trading activities reduced cash from operations by $225 million compared to the same period in 2007.

Net Cash Used in Investing Activities

For the six months ended June 30, 2008, net cash used in investing activities was approximately $50 million less than the same period in 2007. This was due to:

- *Capital expenditures* — NRG's capital expenditures increased by $204 million due to *Repowering*NRG projects, primarily related to $219 million in deposits 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 $229 million in 2008.
- *Asset sales* — The Company received $14 million in proceeds primarily from the sale of rail cars in the first six months of 2008 compared to proceeds of $29 million for the sale of Red Bluff and Chowchilla II power plants in the same period in 2007 for a net decrease in cash of $15 million.
- *Purchases of emission allowances* — Net purchases and sales of emission allowances resulted in an increase in cash of $61 million for the first six months of 2008 compared to 2007.
- *Equity Contribution* — The Company contributed approximately $17 million to its equity investment in Sherbino.

Net Cash Used in Financing Activities

For the six months ended June 30, 2008, net cash used by financing activities decreased by approximately $58 million compared to 2007, due to:

- *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.
- *Term B loan debt payment* — In 2008, the Company paid down $158 million of its Term B loan, including the payment of excess cash flow, as discussed above under *Debt Service Obligations*. The Company paid down $17 million of its Term B loan in the first half of 2007 for a net cash decrease of $141 million for the first six months of 2008 compared to the same period in 2007.
- *Share repurchase* — During the first half of 2008, the Company repurchased approximately $55 million shares of NRG common stock, compared to $215 million for the first half of 2007 for a net $160 million increase to cash for the first six months of 2008 compared to the same period in 2007.
- *Payment of financing element of acquired derivatives* — In the first half of 2008, the Company paid approximately $28 million related to the settlement of gas swaps related to the acquisition of Texas Genco in 2006.
- *Exercise of stock options* — The Company received proceeds of $8 million from the exercise of stock options for the first half of 2008.

NOL's, Deferred Tax Assets and FIN 48 Implications

As of June 30, 2008, the Company had generated a total domestic continuing pre-tax book loss of $40 million and foreign continuing pre-tax book income of $50 million. In addition, NRG has cumulative foreign NOL carryforwards of $307 million, of which $78 million will expire starting in 2011 through 2017 and $229 million do not have an expiration date.

In addition to these amounts, the Company has $709 million of tax affected 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, future U.S. domestic income tax payments will be approximately 30% of pre-tax book income beginning in 2009.

However, as the position remains uncertain, of the $709 million of tax affected unrecognized tax benefits, the Company has recorded a non-current tax liability of $239 million and may accrue the remaining balance as an increase to non-current liabilities until final resolution with the related taxing authority. As of June 30, 2008, NRG has recorded a $239 million non-current tax liability for unrecognized tax benefits, resulting from taxable earnings for the period for which there are insufficient 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 is expected to commence in the third quarter 2008 and continue for approximately 18 to 24 months.

New and On-going Company Initiatives

***FOR*NRG Update**

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 in pre-tax income improvements 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 June 2008, the Company estimated having reached $241 million towards its goal of $250 million under this program. The Company anticipates launching *FOR*NRG 2.0 program during the fourth quarter 2008.

Nuclear Innovation North America

On March 25, 2008, NRG announced the formation of 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.

On April 21, 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.

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.

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

*Repowering*NRG 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.

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 600MW IGCC plant at its existing Huntley facility. As part of the conditional award, a strategic alliance was formed between NYPA and NRG to pursue various initiatives to close the perceived pricing gap between NRG's proposal and NYPA's requirements. On July 16, 2008, NYPA informed the Company of its intent to allow the strategic alliance to expire on July 22, 2008.

Plants under Construction

The Company has three projects under construction, two of which (Sherbino I Wind Farm and the Elbow Creek Wind Farm) broke ground during the first quarter 2008.

In February 2008, a wholly-owned subsidiary of NRG entered into a 50/50 joint venture with a subsidiary of BP to build and own Sherbino. This is a 150 MW wind project consisting of 50 Vestas 3 MW wind turbine generators, located approximately 40 miles east of Fort Stockton in Pecos County, Texas. The project is scheduled to reach commercial operations by the end of 2008 with NRG's 50 percent ownership providing a net capacity of 75 MW.

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

El Segundo Energy Center LLC

On March 7, 2008, NRG, through its wholly-owned subsidiary, El Segundo Energy Center LLC, executed a 10-year tolling agreement with Southern California Edison. Pre-construction activities, including a $17 million non-refundable deposit to the equipment provider to meet the construction schedule, started shortly thereafter on a 550 MW rapid response combined cycle facility in El Segundo, California. The project is scheduled to reach commercial operations by June 1, 2011.

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. On June 25, 2008, the DPUC awarded GenConn the opportunity to execute a contract to build 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.

econrg Update

Commercial Scale Carbon Capture and Sequestration Demonstration

In April 2008, NRG signed a development agreement with Powerspan Corp., or Powerspan, to jointly perform engineering work to support the design and construction of a post-combustion carbon capture and sequestration project demonstration. The development agreement contemplates the project to be constructed at NRG's W.A. Parish plant near Sugar Land, Texas, and to be designed to capture and sequester up to 90% of the carbon dioxide from flue gas equal in quantity to that from a 125 MW unit using Powerspan's proprietary ECO_2 TM technology, a post-combustion, regenerative process which uses an ammonia-based solution to capture CO_2 from the flue gas and release it in a form that is ready for safe transportation and permanent geological storage. The CO_2 from the process would either be sequestered or sold for use in enhanced oil recovery projects. The project, which is expected to be operational in 2012, will be funded by NRG, potential partners and federal and state grants.

Plasma Gasification Technology

On April 3, 2007, NRG purchased approximately 2.2 million shares at CAD$2.25 per share for a less than 6% interest in Alter Nrg Corporation, a Canadian company that provides alternative energy solutions using plasma gasification, a process that converts carbon-containing materials into synthetic gas. NRG has been granted an exclusive license to use Alter Nrg Corp's plasma torch technology to repower unit 6 of the Company's Somerset facility in Somerset, Massachusetts. Qualified approval of the project by the Massachusetts Department of Environmental Protection was received in January 2008 to convert the Somerset facility to a coal and biomass gasification power generation facility. An appeal of the approval was subsequently filed. On June 13, 2008, the presiding officer of the appeal proceedings recommended that the appeal be denied and relief be granted to Somerset extending the time to convert the facility. We are awaiting the issuance of the final decision in the appeal.

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 June 30, 2008, based on the Company's stock price, the redemption value of this embedded derivative was approximately $162 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 the agreement is a feature which is 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. As of June 30, 2008, based on the Company's stock price, the redemption value on the CSF I and CSF II embedded derivatives was approximately $97 million and $15 million, respectively.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

Variable interest in Equity investments —As of June 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, including Sherbino I Wind Farm LLC (hereinafter discussed), 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 $204 million as of June 30, 2008. This indebtedness may restrict the ability of these affiliates to issue dividends or distributions to NRG.

As previously discussed, NRG and BP entered into a 50/50 joint venture in February 2008 to build and own the Sherbino I Wind Farm LLC, or Sherbino. A wholly-owned subsidiary of NRG is managing the construction that is being conducted by an independent Engineering, Procurement and Construction contractor, and an affiliate of BP will manage the operations once commercial operations commence. The project will be funded through a combination of equity contributions from the owners and non-recourse project-level debt. 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. Sherbino has also entered into a long-term natural gas swap to mitigate a portion of power price risk for its expected power generation.

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. On January 30, 2008, NRG entered into an agreement with Bank of America, whereby Bank of America has also agreed to be an issuing bank under the revolver portion of the Company's Senior Credit Facility. Bank of America has agreed to issue up to $250 million of letters of credit under the revolver. This increases the amount of unfunded letters of credit the Company can issue under its Revolving Credit Facility 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 June 30, 2008, the Company had issued $973 million in letters of credit under the Synthetic Letter of Credit Facility. In addition, as of June 30, 2008, the Company had issued $3 million in letters of credit under the Revolving Credit Facility. 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 13, *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 second 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 U.S. 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.

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 June 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 $58 million.

The following table summarizes average, maximum and minimum VAR for NRG:

(In millions) VAR (a)	2008	2007
Three months ended June 30:	$ 58	$ 33
Average	50	22
Maximum	63	33
Minimum	39	15
Six months ended June 30:	$ 58	$ 33
Average	52	24
Maximum	65	34
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 June 30, 2008, for the entire term of these instruments entered into for both asset management and trading was approximately $32 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 June 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 June 30, 2008, the Company would have owed the counterparties approximately $73 million. Based on the investment grade rating of the counterparties, NRG believes its exposure to credit risk due to nonperformance by counterparties to its hedge contracts to be insignificant.

NRG has both long- and short-term debt instruments that subject the Company to the risk of loss associated with movements in market interest rates. As of June 30, 2008, a 100 basis point change in interest rates would result in a $12 million change in interest expense on a rolling twelve month basis.

As of June 30, 2008, the Company's long-term debt fair value was $7.8 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 $439 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 MWh increase or decrease in electricity prices across the term of the marginable contracts would cause a change in margin collateral outstanding of approximately $14 million as of June 30, 2008. This analysis uses simplified assumptions and is calculated based on portfolio composition and margin-related contract provisions as of June 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 the credit risk of NRG and its subsidiaries 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 has credit protection within various agreements to call on additional collateral support if and when necessary. As of June 30, 2008, NRG held net collateral of approximately $324 million from counterparties.

A portion of NRG's credit risk is related to transactions that are recorded in the Company's consolidated Balance Sheets. These transactions primarily consist of current and non-current asset positions from the Company's marketing and risk management operation that are accounted for using mark-to-market accounting, as well as amounts owed by counterparties for transactions that settled but have not yet been paid.

The following table highlights the credit quality and their balance sheet settlement exposures related to these activities as of June 30, 2008:

(In millions, except ratios) Credit Exposure	Exposure Before Collateral	Collateral	Net Exposure
Investment grade	$ 7,230	$ 1,163	$ 6,067
Non-investment grade	262	46	216
Not rated	368	19	349
Total	$ 7,860	$ 1,228	$ 6,632
Investment grade	92%	95%	92%
Non-investment grade	3%	4%	3%
Not rated	5%	1%	5%

Additionally, the Company has concentrations of suppliers and customers among coal suppliers, electric utilities, energy marketing and trading companies, and regional transmission operators. These concentrations of counterparties may impact NRG's overall exposure to credit risk, either positively or negatively, in that counterparties may be similarly affected by changes in economic, regulatory and other conditions.

As of June 30, 2008, NRG's credit risk to significant counterparties greater than 10% was $5.6 billion out of the Company's net exposure of $6.6 billion. 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 non-exchange traded 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 June 30, 2008, based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts as of June 30, 2008:

Derivative Activity Losses	(In millions)
Fair value of contracts as of December 31, 2007	$ (492)
Contracts realized or otherwise settled during the period	35
Changes in fair value	(2,357)
Fair value of contracts as of June 30, 2008	$ (2,814)

	Fair Value of Contracts as of June 30 2008				
(In millions) Sources of Fair Value Gains/(Losses)	Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in excess 5 Years	Total Fair Value
Prices actively quoted	$ (113)	$ (12)	$ —	$ —	$ (125)
Prices provided by other external sources	(535)	(1,375)	(620)	(63)	(2,593)
Prices provided by models and other valuation methods	(40)	(57)	1	—	(96)
Total	$ (688)	$ (1,444)	$ (619)	$ (63)	$ (2,814)

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. 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. The terms for which such price information is available vary by commodity, region and product. The remainder of the assets and liabilities represents contracts for which external valuations are not available. The fair values in each category reflect the level of forward prices and volatility factors as of June 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.

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 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 June 30, 2008, NRG's net derivative liability was $2,814 million, an increase of $2,322 million as compared to December 31, 2007. This increase was primarily driven by increases in coal, gas and power prices.

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 June 30, 2008, no foreign currency options or forward contracts were 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 June 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 June 30, 2008, see Note 13 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

None.

ITEM 3 — DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4 — SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

The stockholders of NRG voted on three items at the Annual Meeting of Stockholders held on May 14, 2008:

1. The election of Class II Directors to a three-year term.
2. The proposal to approve the NRG Energy, Inc. Employee Stock Purchase Plan.
3. The proposal to ratify the appointment of KPMG LLP as NRG's independent registered public accounting firm.

There were 235,966,580 shares of common and preferred stock entitled to vote at the meeting and a total of 226,452,312 shares (approximately 96%) were represented at the meeting.

The four individuals named below were elected to serve a three-year term as Class II Directors expiring at the annual meeting of stockholders in 2011:

Nominee	Votes For	Votes Withheld
Lawrence S. Coben	224,175,391	1,114,476
Paul W. Hobby	224,193,976	1,095,891
Herbert H. Tate	223,919,599	1,370,268
Walter R. Young	223,918,488	1,371,379

The names of the directors whose terms as directors continued after the meeting are as follows:

- Class I: David Crane, Stephen L. Cropper, Thomas W. Weidemeyer
- Class III: John F. Chlebowski, Howard E. Cosgrove, William E. Hantke, Anne C. Schaumburg

The proposal to approve the NRG Employee Stock Purchase Plan was approved with 182,078,559 shares voting for, 809,150 shares voting against, 52,232 shares abstaining, and 43,512,371 broker non-votes.

The proposal to ratify the appointment of KPMG LLP as independent registered public accounting firm was ratified with 226,290,897 shares voting for, 108,654 shares voting against, 52,761 shares abstaining and zero broker non-votes.

ITEM 5 — OTHER INFORMATION

None.

ITEM 6 — EXHIBITS

Exhibits

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: August 1, 2008

EXHIBIT INDEX

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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.

EXHIBIT 31.1

CERTIFICATION

I, David W. Crane, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NRG Energy, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under the Company's supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under the Company's supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report the Company's conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on the Company's most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DAVID W. CRANE

David W. Crane
Chief Executive Officer
(Principal Financial Officer)

Date: August 1, 2008

EXHIBIT 31.2

CERTIFICATION

I, Clint C. Freeland, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NRG Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under the Company's supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under the Company's supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report the Company's conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on the Company's most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CLINT C. FREELAND

Clint C. Freeland
Chief Financial Officer
(Principal Financial Officer)

Date: August 1, 2008

EXHIBIT 31.3

CERTIFICATION

I, James J. Ingoldsby, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NRG Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under the Company's supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under the Company's supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report the Company's conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on the Company's most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JAMES J. INGOLDSBY

James J. Ingoldsby
Chief Accounting Officer
(Principal Accounting Officer)

Date: August 1, 2008

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of NRG Energy, Inc. on Form 10-Q for the quarter ended June 30, 2008, as filed with the Securities and Exchange Commission on the date hereof (the "Form 10-Q"), each of the undersigned officers of the Company certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to such officer's knowledge:

(1) The Form 10-Q fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of the Company as of the dates and for the periods expressed in the Form 10-Q.

Date: August 1, 2008

/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)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to NRG Energy, Inc. and will be retained by NRG Energy, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.