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, 2005 **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 an accelerated filer (as defined in Rule 12 b-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 August 3, 2005, there were 87,047,034 shares of common stock outstanding.

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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 our 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 statement. These factors, risks and uncertainties include the factors described under Risks Related to NRG Energy, Inc. in Item 1 of the Company’s Annual Report on Form 10-K and the following:

- 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 fossil 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 we may not have adequate insurance to cover losses as a result of such hazards;
- Our potential inability to enter into contracts to sell power and procure fuel on terms and prices acceptable to us;
- The liquidity and competitiveness of wholesale markets for energy commodities;
- Changes in government regulation, including possible changes of market rules, market structures and design, rates, tariffs, environmental laws and regulations and regulatory compliance requirements;
- Price mitigation strategies and other market structures or designs employed by independent system operators, or ISOs, or regional transmission organizations, or RTOs, that result in a failure to adequately compensate our generation units for all of their costs;
- Our ability to borrow additional funds and access capital markets, as well as our substantial indebtedness and the possibility that we may incur additional indebtedness going forward;
- Significant operating and financial restrictions placed on us contained in the indenture governing our 8% second priority senior secured notes due 2013, our amended and restated credit facility as well as in debt and other agreements of certain of our subsidiaries and project affiliates generally; and
- Our ability to complete the preferred stock issuance and share repurchase as described in this Form 10-Q.

Forward-looking statements speak only as of the date they were made, and we undertake 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 our actual results to differ materially from those contemplated in any forward-looking statements included in this Quarterly Report on Form 10-Q should not be construed as exhaustive.

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NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30, 2005	June 30, 2004	June 30, 2005	June 30, 2004
	(In thousands, except for per share amounts)			
Operating Revenues				
Revenues from majority-owned operations	$584,567	$573,623	$1,185,709	$1,173,888
Operating Costs and Expenses				
Cost of majority-owned operations	436,470	353,258	889,392	735,011
Depreciation and amortization	47,749	53,168	96,173	108,174
General, administrative and development	53,164	45,746	103,058	82,138
Other charges				
Corporate relocation charges	456	5,645	3,911	6,761
Reorganization items	—	(2,661)	—	3,589
Impairment charges	223	1,676	223	1,676
Total operating costs and expenses	538,062	456,832	1,092,757	937,349
Operating Income	46,505	116,791	92,952	236,539
Other Income (Expense)				
Minority interest in earnings of consolidated subsidiaries	(407)	(201)	(881)	(709)
Equity in earnings of unconsolidated affiliates	16,460	46,101	53,424	63,814
Write downs and gains/(losses) on sales of equity method investments	11,561	1,205	11,561	(533)
Other income, net	7,654	8,051	33,156	11,708
Refinancing expense	—	—	(25,024)	(30,417)
Interest expense	(50,560)	(66,225)	(106,551)	(128,954)
Total other expense	(15,292)	(11,069)	(34,315)	(85,091)
Income From Continuing Operations Before Income Taxes	31,213	105,722	58,637	151,448
Income Tax Expense	8,081	36,322	12,883	50,602
Income From Continuing Operations	23,132	69,400	45,754	100,846
Income from discontinued operations, net of income taxes	734	13,624	730	12,413
Net Income	23,866	83,024	46,484	113,259
Preference stock dividends	4,200	—	8,072	—
Income Available for Common Stockholders	$ 19,666	$ 83,024	$ 38,412	$ 113,259
Weighted Average Number of Common Shares Outstanding — Basic	87,046	100,080	87,045	100,051
Income From Continuing Operations per Weighted Average Common Share — Basic	$ 0.22	$ 0.69	$ 0.43	$ 1.01
Income From Discontinued Operations per Weighted Average Common Share — Basic	0.01	0.14	0.01	0.12
Net Income per Weighted Average Common Share — Basic	$ 0.23	$ 0.83	$ 0.44	$ 1.13
Weighted Average Number of Common Shares Outstanding — Diluted	87,775	100,478	87,729	100,214
Income From Continuing Operations per Weighted Average Common Share — Diluted	$ 0.21	$ 0.69	$ 0.42	$ 1.01
Income From Discontinued Operations per Weighted Average Common Share — Diluted	0.01	0.14	0.01	0.12
Net Income per Weighted Average Common Share — Diluted	$ 0.22	$ 0.83	$ 0.43	$ 1.13

See notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2005 (unaudited)	December 31, 2004
	(In thousands)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 823,161	$ 1,110,045
Restricted cash	87,248	112,824
Accounts receivable, less allowance for doubtful accounts	313,660	272,101
Current portion of notes receivable	25,100	85,447
Income taxes receivable	38,877	37,484
Inventory	228,995	248,010
Derivative instruments valuation	59,524	79,759
Prepayments and other current assets	294,062	169,608
Deferred income taxes	1,262	—
Current assets — discontinued operations	—	3,010
Total current assets	1,871,889	2,118,288
Property, plant and equipment, net of accumulated depreciation of $301,371 and $207,536	3,308,650	3,374,551
Other Assets		
Equity investments in affiliates	637,881	734,950
Notes receivable, less current portion, less reserve for uncollectible notes of $3,794 and $8,196	723,461	804,522
Intangible assets, net	275,854	294,350
Derivative instruments valuation	13,415	41,787
Funded letter of credit	350,000	350,000
Other non-current assets	100,514	111,580
Total other assets	2,101,125	2,337,189
Total Assets	$7,281,664	$ 7,830,028
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 90,745	$ 512,252
Accounts payable	150,688	171,722
Derivative instruments valuation	129,623	16,772
Deferred income taxes	—	334
Other bankruptcy settlement	177,424	175,576
Accrued expenses and other current liabilities	237,903	209,923
Current liabilities — discontinued operations	—	1,362
Total current liabilities	786,383	1,087,941
Other Liabilities		
Long-term debt and capital leases	3,120,206	3,253,866
Deferred income taxes	109,438	134,325
Derivative instruments valuation	153,464	148,445
Out-of-market contracts	309,129	318,664
Other non-current liabilities	195,309	187,438
Non-current liabilities — discontinued operations	—	1,081
Total non-current liabilities	3,887,546	4,043,819
Total Liabilities	4,673,929	5,131,760
Minority Interest	7,084	6,104
Commitments and Contingencies		
Stockholders' Equity		
4% Convertible Perpetual Preferred Stock; $.01 par value; 10,000,000 shares authorized, 420,000 outstanding at June 30, 2005 and December 31, 2004 (shown at liquidation value, net of issuance costs)	406,155	406,359
Common Stock; $.01 par value; 500,000,000 shares authorized; 87,045,104 and 87,041,935 outstanding at June 30, 2005 and December 31, 2004	1,000	1,000
Additional paid-in capital	2,423,636	2,417,021
Retained earnings	235,054	196,642
Less treasury stock, at cost — 13,000,000 shares	(405,312)	(405,312)
Accumulated other comprehensive income/(loss)	(59,882)	76,454
Total stockholders' equity	2,600,651	2,692,164
Total Liabilities and Stockholders' Equity	$7,281,664	$ 7,830,028

See notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Three and Six Months Ended June 30, 2005 and June 30, 2004
(Unaudited)

(In thousands)	Serial Preferred Stock	Serial Preferred Shares	Common Stock	Common Shares	Additional Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income/(loss)	Total Stockholders' Equity
Balances at March 31, 2004	$ —	—	$ 1,000	100,000	$ 2,406,771	$ 41,260	$ —	$ (3,176)	$ 2,445,855
Net income						83,024			83,024
Foreign currency translation adjustments								(33,520)	(33,520)
Deferred unrealized gain on derivatives, net								36,739	36,739
Comprehensive income									86,243
Equity based compensation	—	—	—	7	3,980	—	—	—	3,980
Balances at June 30, 2004	$ —	—	$ 1,000	100,007	$ 2,410,751	$ 124,284	$ —	$ 43	$ 2,536,078
Balances at March 31, 2005	$ 406,306	420	$ 1,000	87,045	$ 2,420,982	$ 215,388	$ (405,312)	$ (28,274)	$ 2,610,090
Net income						23,866			23,866
Foreign currency translation adjustments								(26,923)	(26,923)
Deferred unrealized loss on derivatives, net								(4,685)	(4,685)
Comprehensive loss									(7,742)
Issue costs	(151)								(151)
4% preferred stock dividend						(4,200)			(4,200)
Equity based compensation	—	—	—	—	2,654	—	—	—	2,654
Balances at June 30, 2005	$ 406,155	420	$ 1,000	87,045	$ 2,423,636	$ 235,054	$ (405,312)	$ (59,882)	$ 2,600,651

(In thousands)	Serial Preferred Stock	Serial Preferred Shares	Common Stock	Common Shares	Additional Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income/(loss)	Total Stockholders' Equity
Balances at December 31, 2003	$ —	—	$ 1,000	100,000	$ 2,403,429	$ 11,025	$ —	$ 21,802	$ 2,437,256
Net income						113,259			113,259
Foreign currency translation adjustments								(35,933)	(35,933)
Deferred unrealized gain on derivatives, net								14,174	14,174
Comprehensive income									91,500
Equity based compensation	—	—	—	7	7,322	—	—	—	7,322
Balances at June 30, 2004	$ —	—	$ 1,000	100,007	$ 2,410,751	$ 124,284	$ —	$ 43	$ 2,536,078
Balances at December 31, 2004	$ 406,359	420	$ 1,000	87,042	$ 2,417,021	$ 196,642	$ (405,312)	$ 76,454	$ 2,692,164
Net income						46,484			46,484
Foreign currency translation adjustments								(49,764)	(49,764)

Deferred unrealized loss on derivatives, net								(86,572)	(86,572)
Comprehensive loss									(89,852)
Issue costs	(204)								(204)
4% preferred stock dividend						(8,072)			(8,072)
Equity based compensation	—	—	—	3	6,615	—	—	—	6,615
Balances at June 30, 2005	$ 406,155	420	$ 1,000	87,045	$ 2,423,636	$ 235,054	$ (405,312)	$ (59,882)	$ 2,600,651

See notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(In thousands)	
Cash Flows from Operating Activities		
Net income	$ 46,484	$ 113,259
Adjustments to reconcile net income to net cash provided by operating activities		
Distributions in excess of equity in earnings of unconsolidated affiliates	15,925	4,751
Depreciation and amortization	96,173	113,499
Reserve for note and interest receivable	(98)	—
Amortization of debt issuance costs and debt discount	4,958	16,543
Write-off of deferred financing costs/(debt premium)	(8,413)	15,312
Deferred income taxes	(3,625)	49,384
Minority interest	881	2,089
Unrealized (gains)/losses on derivatives	81,710	(21,458)
Asset impairment	223	1,676
Write downs and (gains)/losses on sales of equity method investments	(11,561)	533
Gain on TermoRio settlement	(13,532)	—
Gain on sale of discontinued operations	—	(13,012)
Amortization of power contracts and emission credits	15,140	34,517
Amortization of unearned equity compensation	4,718	7,322
Cash used by changes in working capital, net of disposition affects	(137,464)	(7,058)
Net Cash Provided by Operating Activities	91,519	317,357
Cash Flows from Investing Activities		
Proceeds on sale of equity method investments	64,575	29,693
Proceeds on sale of discontinued operations	—	59,190
Return of capital from (investments in) equity method investments and projects	1,291	(566)
Decrease in notes receivable, net	92,904	15,208
Capital expenditures	(36,537)	(64,676)
Increase/(decrease) in restricted cash and trust funds, net	26,313	(37,291)
Net Cash Provided by Investing Activities	148,546	1,558
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt, net	204,141	490,631
Payment of dividends to preferred stockholders	(8,072)	—
Deferred debt issuance costs	(1,582)	(8,497)
Issuance expense of preferred shares	(204)	—
Principal payments on short and long-term debt	(721,548)	(567,806)
Net Cash Used by Financing Activities	(527,265)	(85,672)
Change in Cash from Discontinued Operations	1,685	10,822
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(1,369)	25,588
Net Increase (Decrease) in Cash and Cash Equivalents	(286,884)	269,653
Cash and Cash Equivalents at Beginning of Period	1,110,045	551,223
Cash and Cash Equivalents at End of Period	$ 823,161	$ 820,876

See notes to condensed consolidated financial statements.

NRG ENERGY, INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1 — General

NRG Energy, Inc., or "NRG Energy", the "Company", "we", "our", or "us", is a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities, the transacting in and trading of fuel and transportation services, and the marketing and trading of energy, capacity and related products in the United States and internationally.

Note 2 — Summary of Significant Accounting Policies

Basis of Presentation

The accompanying unaudited interim condensed consolidated financial statements have been prepared in accordance with the Securities and Exchange Commission'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 we follow are set forth in Note 2, *Summary of Significant Accounting Policies,* to the Company's financial statements in our Annual Report on Form 10-K for the year ended December 31, 2004. 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 condensed consolidated financial statements contain all material adjustments (consisting of normal, recurring accruals) necessary to fairly present our consolidated financial position as of June 30, 2005, the results of our operations and stockholders' equity for the six months and three months ended June 30, 2005 and 2004, and our cash flows for the six months ended June 30, 2005 and 2004. Certain prior-year amounts have been reclassified for comparative purposes.

Restricted Cash

Restricted cash consists primarily of funds held to satisfy the requirements of certain debt agreements and funds held within our projects that are restricted in their use. These funds are used to pay for current operating expenses and current debt service payments, per the restrictions of the debt agreements.

Accounting Estimates

Management of the Company is required to make certain estimates and assumptions during the preparation of the consolidated financial statements in accordance with generally accepted accounting principles. 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 any period. Actual results could differ from those estimates.

New Accounting Pronouncements

During the period, the Financial Accounting Standards Board (FASB) issued Interpretation No. 47 (FIN 47) to Financial Accounting Standard No. 143 (SFAS No. 143) governing the application of Asset Retirement Obligations. FIN 47 clarifies the term "conditional asset retirement obligation" as used in SFAS No. 143. SFAS No. 143 refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional but there may remain some uncertainty as to the timing and/or method of settlement. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred — generally upon acquisition, construction, or development and/or through the normal operation of the asset. SFAS No. 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. FIN 47 clarifies when the company would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective for fiscal years ending after December 15, 2005 and we are currently evaluating the impact of this guidance.

Also during the period, the SEC issued Staff Accounting Bulletin 107 (SAB 107) which addresses the application of SFAS No. 123(R). SAB 107 was issued to assist registrants by simplifying some of the implementation challenges of SFAS No. 123(R) while enhancing the information that investors receive. SAB 107 creates a framework that is premised on two overarching themes — considerable judgment will be required by preparers to successfully implement SFAS No. 123(R), specifically when valuing employee stock options, and that reasonable individuals, acting in good faith, may conclude differently on the fair value of employee stock options. Accordingly, situations in which there is only one acceptable fair value estimate are expected to be rare. In addition, the SEC extended the adoption date to registrants for the implementation of SFAS No. 123(R) and SAB 107 so that they may implement this guidance for their fiscal year which begins after June 15, 2005.

On March 17, 2005, the Emerging Issues Task Force (EITF) issued EITF Issue No. 04-6 (EITF 04-6). EITF 04-6 provides that stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced during the period that the stripping costs are incurred. EITF 04-6 is effective for the first reporting period in fiscal years beginning after December 15, 2005. Our MIBRAG equity investment is a 50% interest in a mining company, which will be negatively affected by this pronouncement. Currently, MIBRAG has an asset totaling €153 million, approximately $185.4 million, representing the stripping costs incurred during production as of June 30, 2005. We are currently evaluating the implementation of this guidance.

Also during the period, the FASB issued SFAS No. 154 "*Accounting Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3"* (SFAS No. 154). This Statement replaces APB Opinion No. 20, Accounting Changes, and FASB Statement No. 3, Reporting Accounting Changes in Interim Financial Statements, and changes the requirements for the accounting for and reporting of a change in accounting principle. This Statement applies to all voluntary changes in accounting principle. It also applies to changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. APB Opinion No. 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. This Statement requires retrospective application to prior periods' financial statements of changes in accounting principle for direct effects of the change, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change, and redefines restatement as the revising of previously issued financial statements to reflect the correction of an error. This Statement shall be effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

Also during the period, the FASB issued Staff Position 150-1 "Issuer's Accounting under FASB Statement *No. 150 for Freestanding and Other Similar Instruments on Shares That Are Redeemable"* (FSP FAS 150-1). This Staff Position clarifies the application of paragraph 11 of SFAS No. 150, *"Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity"* (SFAS No. 150), and requires classification as a liability of warrants for an issuer's equity shares that are puttable under paragraph 11 of SFAS No. 150 because the warrants embody obligations to repurchase the issuer's shares and may require a transfer of assets. The guidance in FSP FAS 150-1 applies to the first reporting period beginning after June 30, 2005. If the guidance in this FSP results in changes to previously reported information, the cumulative effect shall be reported according to the transition provisions of SFAS No. 150 in the first reporting period beginning after June 30, 2005. Currently, this guidance does not materially affect our consolidated financial position, results of operations or cash flows.

On July 12, 2005, the FASB issued Staff Position APB 18-1, "*Accounting by an Investor for Its Proportionate Share of Accumulated Other Comprehensive Income of an Investee Accounted for under the Equity Method in Accordance with APB Opinion No. 18 upon a Loss of Significant Influence*" (FSP APB 18-1). This guidance clarifies the application of paragraph 121 of SFAS No. 130, "*Reporting Comprehensive Income*" (SFAS No. 130), and clarifies that the company's proportionate share of an investee's equity adjustments for OCI should be offset against the carrying value of the investment at the time significant influence is lost. To the extent that the offset results in a carrying value of the investment that is less than zero, an investor should (a) reduce the carrying value of the investment to zero and (b) record the remaining balance in income. The guidance in FSP APB 18-1 is effective as of the first reporting period after July 12, 2005. Currently, this guidance does not materially affect our consolidated financial position, results of operations or cash flows.

Note 3 — Discontinued Operations

We have classified certain 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 all of these businesses have been accounted for as discontinued operations. Accordingly, current period operating results and prior periods have been restated to report the operations as discontinued.

Statement of Financial Accounting Standards, or SFAS No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets"* requires that discontinued operations be valued on an asset-by-asset basis at the lower of carrying amount or fair value less costs to sell. In applying those provisions, our management considered cash flow analyses and offers related to the assets and businesses. This amount is included in income/(loss) from discontinued operations, net of income taxes in the accompanying condensed consolidated statements of operations. In accordance with SFAS No. 144, assets held for sale will not be depreciated commencing with their classification as such.

The assets and liabilities reported in the balance sheet as of December 31, 2004 as discontinued operations represent those of NRG McClain. The assets of NRG McClain were sold in July 2004 however certain assets and liabilities remained to effect its liquidation and on April 29, 2005, we settled all outstanding obligations of NRG McClain. All other projects were sold as of December 31, 2004.

For the three and six months ended June 30, 2005, discontinued operations consisted of activity related to NRG McClain as noted above. For the three and six months ended June 30, 2004, discontinued operations included our NRG McClain LLC; Penobscot Energy Recovery Company, or PERC; Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee; Hsin Yu, LSP Energy (Batesville) and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha and NEO Tajiguas LLC). McClain, PERC and LSP Energy (Batesville) are included in our Wholesale Power Generation — Other North America segment. Cobee and Hsin Yu are included in the All Other — Other International segment and the four NEO projects are included in the All Other - Alternative Energy segment.

Summarized results of operations of discontinued operations were as follows:

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
		(In thousands)		
Operating revenues	$ —	$ 43,309	$ —	$ 102,185
Pre-tax income from operations of discontinued operations	734	1,732	730	1,502
Income on discontinued operations, net of income taxes	734	13,624	730	12,413

Note 4 — Write Downs and Gains/(Losses) on Sales of Equity Method Investments

Write downs and gains/(losses) on sales of equity method investments recorded in the condensed consolidated statement of operations include the following:

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
		(In thousands)		
Enfield	$ 11,561	$ —	$ 11,561	$ —
Calpine Cogeneration	—	500	—	$ 735
Loy Yang	—	705	—	(1,268)
Total write downs and gains/(losses) on sales of equity method investments	$ 11,561	$ 1,205	$ 11,561	$ (533)

Enfield — On April 1, 2005, we completed the sale of our 25% interest in Enfield to Infrastructure Alliance Limited. The sale resulted in net pre-tax proceeds of $64.6 million. A pre-tax gain of approximately $11.6 million was recorded in the second quarter of 2005.

Calpine Cogeneration — In January 2004, we executed an agreement to sell our 20% interest in Calpine Cogeneration Corporation to Calpine Power Company. The transaction closed in March 2004 and resulted in net cash proceeds of $2.5 million and a net gain of $0.2 million. During the second quarter of 2004, we received additional consideration on the sale of $0.5 million, resulting in an adjusted net gain of $0.7 million.

Loy Yang — During the first quarter of 2004, we wrote down our investment in Loy Yang by $2.0 million due to recent estimates of the expected sales proceeds. In April 2004, we completed the sale of our 25.4% interest in Loy Yang to Great Energy Alliance Corporation, which resulted in net cash proceeds of $26.7 million and a gain of $0.7 million. This resulted in an adjusted loss of $1.3 million for the six months ended June 30, 2004.

Note 5 —Corporate Relocation Charges

On March 16, 2004, we announced plans to implement a new regional business strategy and structure. The new plan called for a reorganized management structure and corporate headquarters relocation to Princeton, New Jersey. The transition of our corporate headquarters was completed in December 2004.

For the six months ended June 30, 2005 and 2004, we recorded $3.9 million and $6.8 million, respectively, for charges related to our corporate relocation activities, primarily for employee severance and termination benefits, employee related transition costs and lease termination costs. These charges are classified separately in our statement of operations, in accordance with SFAS No. 146, "*Accounting for Costs Associated with Exit or Disposal Activities*". Relocation charges for the year ended December 31, 2004 were $16.2 million. We expect to incur an additional $1.0 million in the third and fourth quarters of 2005 of SFAS No. 146-classified expenses in connection with corporate relocation charges for a total of $21.1 million.

A summary of the SFAS No. 146-classified expenses is as follows:

	Year Ended December 31, 2004	Six Months Ended June 30, 2005	Yet to be Incurred	Expected Total Charges
		(In thousands)		
Employee related transition costs	$ 8,595	$ 931	$ 424	$ 9,950
Severance and termination benefits	6,505	172	—	6,677
Lease termination costs	1,067	2,808	554	4,429
Total corporate relocation charges	$ 16,167	$ 3,911	$ 978	$ 21,056

A summary of the significant components of the restructuring liability is as follows:

	Balance at December 31, 2004	Restructuring Related Charges	Cash Receipts/ (Payments)	Balance at June 30, 2005
		(In thousands)		
Employee related transition costs	$ (1,425)	$ 931	$ 452	$ (42)
Severance and termination benefits	4,939	507	(4,895)	551
Lease termination costs	796	2,808	(631)	2,973
Total	$ 4,310	$ 4,246	$ (5,074)	$ 3,482

As of June 30, 2005, the restructuring liability was $3.5 million the majority of which is included in other current liabilities on the condensed consolidated balance sheet. The restructuring liability excludes pension curtailment gains of $0.8 million and $0.3 million which was credited to the corporate relocation charge for the 2004 fiscal year and six months ended June 30, 2005, respectively. All restructuring costs are recorded at our corporate level within our All Other — Other segment, in the corporate relocation charges line on the consolidated statement of operations. Severance and termination benefits require that cash payments be made through the fourth quarter of 2005. Lease termination costs require that cash payments be made through the fourth quarter of 2006.

Note 6 — Investments Accounted for by the Equity Method

We have a 50% interest in one company, West Coast Power, or WCP, which was considered significant, as defined by applicable SEC regulations.

West Coast Power LLC Summarized Results of Operations

For the three and six months ended June 30, 2005, we recorded equity earnings of $4.4 million and $8.5 million, respectively, for WCP after adjustments for the reversal of $3.1 million and $6.3 million, respectively, of project level depreciation expense. For the three and six months ended June 30, 2004, we recorded equity earnings of $21.9 million and $27.9 million, respectively, after adjustments for the reversal of $5.6 million and $7.6 million, respectively, of project level depreciation expense, offset by a decrease in earnings related to $30.6 million and $61.6 million, respectively, of amortization of the intangible asset for the California Department of Water Resources, or CDWR contract. As discussed in Note 13, *Investments Accounted for by the Equity Method,* in our Annual Report on Form 10-K for the year ended December 31, 2004, the amortization of an intangible is a result of pushing down the impact of Fresh Start to the project's balance sheet, as we established a contract-based intangible asset with a one-year remaining life, consisting of the value of WCP's CDWR energy sales contract. The following table summarizes financial information for West Coast Power, including interests owned by us and other parties for the periods shown below:

(In millions)	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
Operating revenues	$ 72	$ 185	$ 158	$ 352
Operating income	2	94	2	164
Income before tax	2	94	4	164

Note 7 — Accounting for Derivative Instruments and Hedging Activities

SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" (SFAS No. 133), as amended, requires us to recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. If certain conditions are met, we may be able to designate our derivatives as cash flow hedges and defer the effective portion of the change in fair value of the derivatives in Accumulated Other Comprehensive Income (OCI) and subsequently recognize in earnings when the hedged items impact income. The ineffective portion of a cash flow hedge is immediately recognized in income.

For derivatives designated as hedges of the fair value of assets or liabilities, the changes in fair value of both the derivatives and the hedged items are recorded in current earnings. The ineffective portion of a hedging derivative instrument's change in fair value will be immediately recognized in earnings.

For derivatives that are neither designated as cash flow hedges or do not qualify for hedge accounting treatment, the changes in the fair value will be immediately recognized in earnings. Under the guidelines established by SFAS No. 133, as amended, certain derivative instruments may qualify for the normal purchase and sale exception and are therefore exempt from fair value accounting treatment. SFAS No. 133 applies to our energy related commodity contracts, interest rate swaps and foreign exchange contracts.

As the Company engages principally in the trading and marketing of its generation assets, most of our commercial activities qualify for hedge accounting under the requirements of SFAS No.133. In order to so qualify, the physical generation and sale of electricity must be highly probable at inception of the trade and throughout the period it is held, as is the case with our base-load coal plants. For this reason, trades in support of the company's peaking units will not generally qualify for hedge accounting treatment and any changes in fair value are likely to be reflected on a mark-to-market basis in the statement of operations. The majority of trades in support of our base-load coal units will normally qualify for hedge accounting treatment and any fair value movements will be reflected in the balance sheet as part of Other Comprehensive Income.

Accumulated Other Comprehensive Income (OCI)

The following table summarizes the effects of SFAS No. 133 on our OCI balance attributable to hedged derivatives for the three months ended June 30, 2005 before income taxes:

	Energy Commodities	Interest Rate	Foreign Currency	Total
		(In thousands)		
Accumulated OCI balance at March 31, 2005	$ (87,043)	$ 12,625	$ —	$(74,418)
Unwound from OCI during the period:				
— Due to unwinding of previously deferred amounts	1,036	259	—	1,295
Mark-to-market of hedge contracts (net of tax)	9,301	(15,281)	—	(5,980)
Accumulated OCI balance at June 30, 2005	$ (76,706)	$ (2,397)	$ —	$(79,103)
Gains/(Losses) expect to unwind from OCI during the next 12 months	(59,480)	5,735	—	(53,745)

The following table summarizes the effects of SFAS No. 133 on our OCI balance attributable to hedged derivatives for the six months ended June 30, 2005 before income taxes:

	Energy Commodities	Interest Rate	Foreign Currency	Total
		(In thousands)		
Accumulated OCI balance at December 31, 2004	$ 5,482	$ 1,987	$ —	$ 7,469
Unwound from OCI during the period:				
— Due to unwinding of previously deferred amounts	(1,719)	863	—	(856)
Mark-to-market of hedge contracts (net of tax)	(80,469)	(5,247)	—	(85,716)
Accumulated OCI balance at June 30, 2005	$ (76,706)	$(2,397)	$ —	$(79,103)
Gains/(Losses) expect to unwind from OCI during the next 12 months	(59,480)	5,735	—	(53,745)

The following table summarizes the effects of SFAS No. 133 on our OCI balance attributable to hedged derivatives for the three months ended June 30, 2004:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Accumulated OCI balance at March 31, 2004	$ (15,271)	$ (7,817)	$ —	$(23,088)
Unwound from OCI during period:				
— Due to unwinding of previously deferred amounts	9,408	3,272	—	12,680
Mark-to-market of hedge contracts	(3,079)	27,138	—	24,059
Accumulated OCI balance at June 30, 2004	$ (8,942)	$22,593	$ —	$ 13,651

The following table summarizes the effects of SFAS No. 133 on our OCI balance attributable to hedged derivatives for the six months ended June 30, 2004:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Accumulated OCI balance at December 31, 2003	$ (1,953)	$ 1,600	$ (170)	$ (523)
Unwound from OCI during period:				
— Due to unwinding of previously deferred amounts	8,784	7,058	170	16,012
Mark-to-market of hedge contracts	(15,773)	13,935	—	(1,838)
Accumulated OCI balance at June 30, 2004	$ (8,942)	$22,593	$ —	$13,651

Losses of $1.3 million and gains of $0.9 million were reclassified from OCI to current period earnings during the three and six months ended June 30, 2005 due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items are recorded. Also during the three and six months ended June 30, 2005 we recorded losses in OCI of approximately $6.0 million and losses of $85.7 million, respectively, related to changes in the fair values of derivatives accounted for as hedges. The net balance in OCI relating to SFAS No. 133 as of June 30, 2005 was an unrecognized loss of approximately $79.1 million. We expect $53.7 million of deferred net losses on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

Statement of Operations

The following tables summarize the pre-tax effects of non-hedge derivatives on our statement of operations for the three months ended June 30, 2005:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Revenue from majority-owned subsidiaries	$ 5,604	$ —	$ —	$ 5,604
Equity in earnings of unconsolidated subsidiaries	—	—	—	—
Cost of operations	3,044	—	—	3,044
Total statement of operations impact before tax	$ 2,560	$ —	$ —	$ 2,560

The following tables summarize the pre-tax effects of non-hedge derivatives on our statement of operations for the six months ended June 30, 2005:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Revenue from majority-owned subsidiaries	$ (81,609)	$ —	$ —	$ (81,609)
Equity in earnings of unconsolidated subsidiaries	11,868	—	—	11,868
Cost of operations	(1,384)	—	—	(1,384)
Interest expense	—	—	—	—
Total statement of operations impact before tax	$ (68,357)	$ —	$ —	$ (68,357)

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the three months ended June 30, 2004:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Revenue from majority-owned subsidiaries	$ 6,572	$ —	$ —	$ 6,572
Equity in earnings of unconsolidated subsidiaries	9,733	560	—	10,293
Cost of operations	1,129	—	—	1,129
Total statement of operations impact before tax	$ 15,176	$ 560	$ —	$ 15,736

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the six months ended June 30, 2004:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Revenue from majority-owned subsidiaries	$ 7,468	$ —	$ —	$ 7,468
Equity in earnings of unconsolidated subsidiaries	8,506	629	—	9,135
Cost of operations	1,632	—	—	1,632
Other income	—	411	—	411
Total statement of operations impact before tax	$ 14,342	$ 1,040	$ —	$ 15,382

Energy Related Commodities

As part of our risk management activities, we manage the commodity price risk associated with our competitive supply activities and the price risk associated with power sales from our electric generation facilities. In doing so, we may enter into a variety of derivative and non-derivative instruments, including the following:

- Forward contracts, which commit us to purchase or sell energy commodities in the future.
- Futures contracts, which are exchange-traded standardized commitments to purchase or sell a commodity or financial instrument.
- Swap agreements, which require payments to or from counter-parties based upon the differential between two prices for a predetermined contractual (notional) quantity.
- Option contracts, which convey the right to buy or sell a commodity, financial instrument, or index at a predetermined price.

The objectives for entering into such hedges include:

- Fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on our electric generation operations.
- Fixing the price of a portion of anticipated fuel purchases for the operation of our power plants.
- Fixing the price of a portion of anticipated energy purchases to supply our load-serving customers.

Ineffectiveness will result from a difference in the relative price movements between a financial transaction and the underlying physical pricing point. If this difference is large enough, it will cause an entity to discontinue the use of hedge accounting. During the three and six months ended June 30, 2005 our pre-tax earnings were affected by an unrealized loss of $1.7 million due to the ineffectiveness associated with financial forward contracted electric sales.

During the three and six months ended June 30, 2005, our pre-tax earnings were affected by an unrealized gain of $2.6 million and unrealized losses of $80.2 million, respectively, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133. These amounts exclude the affect of unrealized gains and losses recorded by equity investee’s.

During the three and six months ended June 30, 2004, our pre-tax earnings were increased by an unrealized gain of $5.4 million and $5.8 million, respectively, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133. These amounts exclude the affect of unrealized gains and losses recorded by equity investee's.

During the three and six months ended June 30, 2005, we reclassified losses of $1.0 million and gains of $1.7 million, respectively, from OCI to current period earnings and expect to reclassify approximately $59.5 million of deferred losses to earnings during the next twelve months on energy related derivative instruments accounted for as hedges.

During the three and six months ended June 30, 2004, we reclassified losses of $9.4 million and $8.8 million, respectively, from OCI to current period earnings.

At June 30, 2005, we had hedge and non-hedge energy related commodity contracts extending through March 2025.

Interest Rates

To manage interest rate risk, we have entered into interest-rate swap agreements that fix the interest payments or the fair value of selected debt issuances. The qualifying swap agreements are accounted for as cash flow or fair value hedges. The effective portion of the cash flow hedges' cumulative gains/losses are reported as a component of OCI in stockholders' equity. These gains/losses are recognized in earnings as the hedged interest expense is incurred. The reclassification from OCI is included on the same line of the statement of operations in which the hedged item appears. The entire amount of the change in fair value hedges is recorded in the statement of operations along with the change in value of the hedged item. Any ineffectiveness on interest rate swaps during the three and six months ended June 30, 2005 and 2004 was immaterial to our financial results.

During the three and six months ended June 30, 2004, pre-tax earnings were increased by an unrealized gain of $0 million and $0.4 million, respectively, related to the change in fair value of one interest rate related derivative instrument. This instrument is a $400 million floating to fixed interest rate swap, which was not designated as an effective hedge of the expected cash flows at March 31, 2004. As of April 1, 2004, this instrument was designated as a cash flow hedge under SFAS No. 133. As a result, subsequent changes to its fair value will be deferred and recorded as part of other comprehensive income.

During the three and six months ended June 30, 2005, we reclassified losses of $0.3 million and $0.9 million, respectively, from OCI to current period earnings and expect to reclassify approximately $5.7 million of deferred gains to earnings during the next twelve months associated with interest rate swaps accounted for as hedges.

During the three and six months ended June 30, 2004, we reclassified losses of $3.3 million and $7.1 million, respectively, from OCI to current period earnings and expect to reclassify immaterial amounts to earnings during the next twelve months associated with interest rate swaps accounted for as hedges.

At June 30, 2005, we had interest rate derivative instruments extending through June 2019.

Foreign Currency Exchange Rates

To preserve the U.S. dollar value of projected foreign currency cash flows, we may hedge, or protect those cash flows if appropriate foreign hedging instruments are available. As of June 30, 2005, the results of any outstanding foreign currency exchange contracts were immaterial to our financial results.

Note 8 — Long-Term Debt

NRG Energy Corporate Debt

In January 2005 and March 2005, we used existing cash to purchase, at market prices, $25 million and $15.8 million, respectively, in face value of our Second Priority Notes. We paid $3.4 million in fees and market premiums on the repurchased notes which were recorded to refinancing expense, and an additional $0.7 million of accrued interest.

On February 4, 2005, we redeemed $375.0 million in Second Priority Notes and paid $30.0 million for the early redemption premium on the redeemed notes which was recorded to refinancing expense. In addition, we paid $4.1 million in accrued but unpaid interest on the redeemed notes and $0.4 million in accrued but unpaid liquidated damages on the redeemed notes.

On June 17, 2005, we announced the commencement of a registered exchange offer to exchange up to $1.35 billion aggregate principal amount of the 8% Second Priority Notes, which have been registered under the Securities Act of 1933, as amended, for all outstanding 8% Second Priority Notes that were issued and sold by NRG in December 2003 and January 2004 in private placement offerings. The sole purpose of this exchange offer was to fulfill our obligations with respect to the registration of the notes issued in the private placements. The exchange offer expired on July 25, 2005 and closed on July 28, 2005.

As of June 30, 2005 and August 3, 2005, our $150.0 million corporate revolving credit facility remained undrawn.

Certain Events Related to Project-Level Debt

In February 2005, NRG Flinders amended its debt facility of AUD 279.4 million (approximately US $218.5 million) in floating-rate debt. The amendment extended the maturity to February 2017, reduced borrowing costs and reserve requirements, reduced debt service coverage ratios, removed mandatory cash sharing arrangements, and made other minor modifications to terms and conditions. The facility includes an AUD 20.0 million (US $15.6 million) working capital and performance bond facility, under which AUD 14.0 million (US $10.6 million) in performance bonds and letters of credit have been issued as of June 30, 2005. An interim arrangement to indemnify ANZ of up to AUD 15.5 million (US $11.8 million) was terminated on May 17, 2005. NRG Flinders is required to maintain interest-rate hedging contracts on a rolling 5-year basis at a minimum level of 60% of principal outstanding. Upon execution of the amendment, a voluntary principal prepayment of AUD 50 million (US $39.1 million) was made. On March 31, 2005 Flinders made voluntary prepayments of AUD 10.5 million (US $8.1 million) and on June 30, 2005, Flinders' made scheduled repayments of AUD 13.1 million (US $10 million), respectively, reducing the outstanding amount to AUD 185.8 million (US $141.5 million). NRG Flinders retains the right to redraw these amounts at any time.

Note 9 — Earnings Per Share

Basic earnings per common share were computed by dividing net income less accumulated preferred stock dividends by the weighted average number of common shares outstanding. Shares issued during the year are weighted for the portion of the year that they were outstanding. Diluted earnings per share are 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 dilutive effect of the potential exercise of outstanding options to purchase shares of common stock is calculated using the treasury stock method. The nonvested restricted stock units are not considered outstanding for purposes of computing basic earnings per share; however these units are included in the denominator for purposes of computing diluted earnings per share under the treasury stock method. The deferred stock units are not considered outstanding for purposes of computing basic earnings per share; however these units are included in the denominator for purposes of computing diluted earnings per share under the if-converted method. The reconciliation of basic earnings per common share to diluted earnings per common share is shown in the following table:

	Three Months Ended		Six Months Ended	
	June 30, 2005	June 30, 2004	June 30, 2005	June 30, 2004
	(In thousands, except per share data)			
Basic earnings per share				
Numerator:				
Income from continuing operations	$ 23,132	$ 69,400	$ 45,754	$ 100,846
Preferred stock dividends	(4,200)	—	(8,400)	—
Net income available to common stockholders from continuing operations	18,932	69,400	37,354	100,846
Discontinued operations, net of tax	734	13,624	730	12,413
Net income available to common stockholders	$ 19,666	$ 83,024	$ 38,084	$ 113,259
Denominator:				
Weighted average number of common shares outstanding	87,046	100,080	87,045	100,051
Basic earnings per share:				
Income from continuing operations	$ 0.22	$ 0.69	$ 0.43	$ 1.01
Discontinued operations, net of tax	0.01	0.14	0.01	0.12
Net income	$ 0.23	$ 0.83	$ 0.44	$ 1.13

	Three Months Ended June 30, 2005	Three Months Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(In thousands, except per share data)			
Diluted earnings per share				
Numerator				
Net income available to common stockholders from continuing operations	$ 18,932	$ 69,400	$ 37,354	$ 100,846
Discontinued operations, net of tax	734	13,624	730	12,413
Net income available to common stockholders	$ 19,666	$ 83,024	$ 38,084	$ 113,259
Denominator:				
Weighted average number of common shares outstanding	87,046	100,080	87,045	100,051
Incremental shares attributable to the issuance of nonvested restricted stock units (treasury stock method)	396	398	378	163
Incremental shares attributable to the assumed conversion of deferred stock units (if-converted method)	112	—	90	—
Incremental shares attributable to the issuance of nonvested nonqualifying stock options (treasury stock method)	221	—	216	—
Total dilutive shares	87,775	100,478	87,729	100,214
Diluted earnings per share:				
Income from continuing operations	$ 0.21	$ 0.69	$ 0.42	$ 1.01
Discontinued operations, net of tax	0.01	0.14	0.01	0.12
Net income	$ 0.22	$ 0.83	$ 0.43	$ 1.13

For the three and six months ended June 30, 2005, outstanding preferred shares which are convertible into 10,500,000 shares of common stock were not included in the computation because the effect would be anti-dilutive. For the three and six months ended June 30, 2004, options to purchase 770,751 and 786,751 shares of common stock at an average price of $23.66 and $23.61, respectively, were not included in the computation because the effect would be anti-dilutive.

Note 10 — Segment Reporting

We conduct the majority of our business within five reportable operating segments. All of our other operations are presented under the "All Other" category. Our reportable operating segments consist of Wholesale Power Generation — Northeast, Wholesale Power Generation — South Central, Wholesale Power Generation — Western, Wholesale Power Generation — Other North America and Wholesale Power Generation — Australia. These reportable segments are distinct components with separate operating results and management structures in place. Included in the All Other category are our Wholesale Power Generation — Other International operations, our Alternative Energy operations, our Non — Generation operations and an Other component which includes primarily our corporate charges (primarily interest expense) that have not been allocated to the reportable segments and the remainder of our operations which are not significant. We have presented this detail within the All Other category, as we believe that this information is important to a full understanding of our business.

Beginning January 1, 2005 management decided to change the allocation criteria of corporate general and administrative expenses to the segments. Prior to 2005, corporate general and administrative expenses were allocated based on an analysis of man hours spent on work for each segment. As of January 1, 2005, corporate general and administrative expenses are allocated based on the forecasted revenue to be generated by each segment. In the following table, we have included a reconciliation of the increase/(decrease) in net income by segment for the three month period and six month period ended June 30, 2005, assuming the prior allocation criteria was still in effect.

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	Three Months Ended June 30, 2005									
	Wholesale Power Generation					All Other				
	Northeast	South Central	Western	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	(in thousands)									
Operations										
Operating revenues	$ 315,676	$ 108,929	$ (25)	$ 9,661	$ 57,137	$ 39,132	$ 20,397	$ 35,080	$ (1,420)	$ 584,567
Depreciation and amortization	18,582	15,085	197	2,010	6,118	858	1,318	2,740	841	47,749
Equity in earnings of unconsolidated affiliates	—	—	7,367	1,843	5,578	1,680	(8)	—	—	16,460
Income/(loss) from continuing operations before income taxes	39,473	(6,817)	5,906	(5,574)	5,355	22,506	3,294	2,371	(35,301)	31,213
Net income/(loss) from continuing operations	39,473	(6,817)	5,909	(6,701)	4,213	18,438	3,120	1,834	(36,337)	23,132
Net income from discontinued operations, net of tax	—	—	—	734	—	—	—	—	—	734
Net income/(loss)	39,473	(6,817)	5,909	(5,967)	4,213	18,438	3,120	1,834	(36,337)	23,866
Total assets	2,046,441	1,067,915	289,093	767,037	826,997	947,180	46,327	676,357	614,317	7,281,664

If the Company continued using the previous years allocation method for corporate general and administrative expenses, the effect to the net income of each segment for the three months ended June 30, 2005 would be as follows:

Net income/(loss) as reported	$ 39,473	$ (6,817)	$ 5,909	$ (5,967)	$ 4,213	$ 18,438	$ 3,120	$ 1,834	$ (36,337)	$ 23,866
Increase/(decrease) in net income	6,766	3,561	22	(412)	1,712	1,090	375	1,327	(14,441)	—
Adjusted net income/(loss)	$ 46,239	$ (3,256)	$ 5,931	$ (6,379)	$ 5,925	$ 19,528	$ 3,495	$ 3,161	$ (50,778)	$ 23,866

	Three Months Ended June 30, 2004									
	Wholesale Power Generation					All Other				
	Northeast	South Central	Western	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	(in thousands)									
Operations										
Operating revenues	$ 275,029	$ 102,497	$ 929	$ 29,587	$ 36,793	$ 39,374	$ 18,781	$ 72,712	$ (2,079)	$ 573,623
Depreciation and amortization	17,382	14,572	203	6,930	6,886	613	1,289	2,729	2,564	53,168
Equity in earnings/(losses) of unconsolidated affiliates	—	—	24,100	2,069	3,534	15,878	521	—	(1)	46,101
Income/(loss) from continuing operations before income taxes	56,230	16,494	23,237	(568)	(8,278)	26,263	4,266	44,152	(56,074)	105,722
Net income/(loss) from continuing operations	56,230	16,494	23,052	(977)	(4,908)	20,957	4,262	43,703	(89,413)	69,400
Net income on discontinued operations, net of tax	—	—	—	1,915	—	12,237	(531)	—	3	13,624
Net income/(loss)	$ 56,230	$ 16,494	$ 23,052	$ 938	$ (4,908)	$ 33,194	$ 3,731	$ 43,703	$ (89,410)	$ 83,024

	Six Months Ended June 30, 2005									
	Wholesale Power Generation						All Other			
	Northeast	South Central	Western	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	(in thousands)									
Operations										
Operating revenues	$648,136	$226,075	$ 150	$ 14,808	$105,923	$ 82,169	$ 35,343	$ 75,958	$ (2,853)	$1,185,709
Depreciation and amortization	37,191	30,227	395	4,003	12,712	1,654	2,634	5,479	1,878	96,173
Equity in earnings of unconsolidated affiliates	—	—	12,092	3,649	11,715	25,957	11	—	—	53,424
Income/(loss) from continuing operations before income taxes	72,333	2,489	9,193	(10,511)	16,169	68,843	4,074	7,495	(111,448)	58,637
Net income/(loss) from continuing operations	72,333	2,489	9,168	(11,859)	14,393	60,706	3,658	6,943	(112,077)	45,754
Net income from discontinued operations, net of tax	—	—	—	730	—	—	—	—	—	730
Net income/(loss)	72,333	2,489	9,168	(11,129)	14,393	60,706	3,658	6,943	(112,077)	46,484

If the Company continued using the previous years allocation method for corporate general and administrative expenses, the effect to the net income of each segment for the six months ended June 30, 2004 would be as follows:

Net income/(loss) as reported	$ 72,333	$ 2,489	$ 9,168	$ (11,129)	$ 14,393	$ 60,706	$ 3,658	$ 6,943	$(112,077)	$ 46,484
Increase/(decrease) in net income	13,355	7,111	(274)	(737)	3,406	2,168	757	2,796	(28,582)	—
Adjusted net income/(loss)	$ 85,688	$ 9,600	$ 8,894	$ (11,866)	$ 17,799	$ 62,874	$ 4,415	$ 9,739	$(140,659)	$ 46,484

	Six Months Ended June 30, 2004									
	Wholesale Power Generation						All Other			
	Northeast	South Central	Western	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	(in thousands)									
Operations										
Operating revenues	$605,569	$197,762	$ (2,393)	$ 50,422	$ 99,022	$ 79,440	$ 32,380	$ 115,438	$ (3,752)	$1,173,888
Depreciation and amortization	35,911	31,534	405	14,540	12,011	1,337	2,678	5,853	3,905	108,174
Equity in earnings/(losses) of unconsolidated affiliates	—	—	30,697	2,301	6,706	23,360	750	—	—	63,814
Income/(loss) from continuing operations before income taxes	143,658	27,871	24,600	(10,470)	8,122	40,617	5,160	53,063	(141,173)	151,448
Net income/(loss) from continuing operations	143,658	27,871	24,263	(11,214)	8,228	31,167	5,152	52,437	(180,716)	100,846
Net income on discontinued operations, net of tax	—	—	—	933	—	12,357	(877)	—	—	12,413
Net income/(loss)	$143,658	$ 27,871	$24,263	$ (10,281)	$ 8,228	$ 43,524	$ 4,275	$ 52,437	$(180,716)	$ 113,259

Note 11 — Income Taxes

Income tax expense for the three and six months ended June 30, 2005 was $8.1 million and $12.9 million, respectively, compared to a tax expense of $36.3 million and $50.6 million, respectively, for the corresponding periods in 2004. The income tax expense for the six months ended June 30, 2005 includes domestic tax expense of $2.8 million and foreign tax expense of $10.1 million. The tax expense for the six months ended June 30, 2004 includes domestic tax expense of $41.0 million and foreign tax expense of $9.6 million.

A reconciliation of the U.S. statutory rate to our effective tax rate from continuing operations for the six months ended June 30, 2005 and 2004 are as follows:

	Six Months Ended			
	June 30, 2005		June 30, 2004	
	Amount	Rate	Amount	Rate
	(Dollars in thousands)			
Income From Continuing Operations Before Income Taxes	$ 58,637		$ 151,448	
Tax	20,523	35.0%	53,007	35.0%
State taxes	(1,482)	(2.5)%	367	0.2%
Foreign operations	(21,807)	(37.2)%	(7,490)	(4.9)%
Permanent differences including subpart F income	12,079	20.5%	1,109	0.7%
Other	3,570	6.1%	3,609	2.4%
Income Tax Expense	$ 12,883	21.9%	$ 50,602	33.4%

For U.S. income tax purposes, the Company generated additional net deferred tax assets of $35 million for the six months ended June 30, 2005 of which a full valuation allowance was applied due to the uncertainty of utilization in future periods.

The effective income tax rate for the six months ended June 30, 2005 differs from the U.S. statutory rate of 35% due to the US income inclusion upon the sale of Enfield and due to earnings in foreign jurisdictions taxed at rates lower than the U.S. statutory rate.

We believe that it is more likely than not that a benefit will not be realized on a substantial portion of our deferred tax assets. This assessment included consideration of positive and negative evidence, our current financial position and results of current operations, projected future taxable income, projected operating and capital gains and our available tax planning strategies. As of June 30, 2005, a consolidated valuation allowance of $725.3 million was recorded against the net deferred tax assets, including net operating loss, or NOL, carryforwards.

Pending our evaluation of the American Jobs Creation Act of 2004, management intends to reinvest indefinitely the earnings from our foreign operations. Currently, our management is reviewing their reinvestment plan pursuant to the Act which provides for a low tax cost on earnings repatriated in 2005 and reinvested in the company's U.S. operations. We are presently estimating a maximum cash balance amount of $307 million which could be remitted from foreign operations to the U.S. by year end and resulting in a federal tax cost of 5.25% under the Act to the extent the Company has earnings and profits. Pending our conclusive evaluation of the Company's cumulative earnings and profits position, we cannot assess the range of income tax cost at this time.

As of June 30, 2005, there is no tax effect resulting from this legislation since management has not concluded upon a repatriation plan. The Company expects to conclude on this issue by the fourth quarter of 2005.

Note 12 — Benefit Plans and Other Postretirement Benefits

Substantially all employees hired prior to December 5, 2003 were eligible to participate in our defined benefit pension plans. We have initiated an NRG Energy noncontributory, defined benefit pension plan effective January 1, 2004, with credit for service from December 5, 2003. In addition, we provide postretirement health and welfare benefits (health care and death benefits) for certain groups of our employees. Generally, these are groups that were acquired in recent years and for whom prior benefits are being continued (at least for a certain period of time or as required by union contracts). Cost sharing provisions vary by acquisition group and terms of any applicable collective bargaining agreements.

NRG Energy Pension and Postretirement Medical Plans

Components of Net Periodic Benefit Cost

The components of net pension and postretirement benefit costs are as follows:

	Pension Benefits			
	Three Months Ended		Six Months Ended	
	June 30, 2005	June 30, 2004	June 30, 2005	June 30, 2004
	(In thousands)			
Service cost benefits earned	$ 3,007	$ 2,950	$ 6,063	$ 5,900
Interest cost on benefit obligation	933	738	1,871	1,476
Expected return on plan assets	(81)	—	(162)	—
Curtailment gain	—	—	(335)	—
Net periodic benefit cost	$ 3,859	$ 3,688	$ 7,437	$ 7,376

	Other Benefits			
	Three Months Ended		Six Months Ended	
	June 30, 2005	June 30, 2004	June 30, 2005	June 30, 2004
	(In thousands)			
Service cost benefits earned	$ 487	$ 465	$ 975	$ 930
Interest cost on benefit obligation	731	630	1,462	1,260
Amortization of net (gain)/loss	19	—	38	—
Net periodic benefit cost	$ 1,237	$ 1,095	$ 2,475	$ 2,190

Note 13 — Commitments and Contingencies

Legal Issues

Set forth below is a description of our material legal proceedings. Pursuant to the requirements of SFAS No. 5, *"Accounting for Contingencies,"* and related guidance, we record reserves for estimated losses from contingencies when information available indicates that a loss is probable and the amount of the loss is reasonably estimable. Because litigation is subject to inherent uncertainties and unfavorable rulings or developments could occur, there can be no certainty that we may not ultimately incur charges in excess of presently recorded reserves. A future adverse ruling or unfavorable development could result in future charges which could have a material adverse effect on NRG Energy's consolidated financial position, results of operations or cash flows.

With respect to a number of the items listed below, management has determined that a loss is not probable or the amount of the loss is not reasonably estimable, or both. In some cases, management is not able to predict with any degree of substantial certainty the range of possible loss that could be incurred. Notwithstanding these facts, management has assessed each of these 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. Management's judgment may, as a result of facts arising prior to resolution of these matters or other factors prove inaccurate and investors should be aware that such judgment is made subject to the known uncertainty of litigation.

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

The Company believes that it has valid defenses to the legal proceedings and investigations described below and intends to defend them vigorously. However, litigation is inherently subject to many uncertainties. There can be no assurance that additional litigation will not be filed against the Company or its subsidiaries in the future asserting similar or different legal theories and seeking similar or different types of damages and relief. Unless specified below, the Company is unable to predict the outcome of these legal proceedings and investigations may have or reasonably estimate the scope or amount of any associated costs and potential liabilities. An unfavorable outcome in one or more of these proceedings could have a material impact on the Company's consolidated financial position, results of operations or cash flows. The Company also has indemnity rights for some of these proceedings to reimburse the Company for certain legal expenses and to offset certain amounts deemed to be owed in the event of an unfavorable litigation outcome.

The descriptions below update, and should be read in conjunction with, the complete descriptions under Note 27, *Commitments and Contingencies*, in NRG Energy's Form 10-K for the year ended December 31, 2004.

California Wholesale Electricity Litigation and Related Investigations

We, West Coast Power, LLC, or WCP, WCP's four operating subsidiaries, Dynegy, Inc. and numerous other unrelated parties are the subject of numerous lawsuits arising based on events occurring in the California power market. Through our subsidiary, NRG West Coast Power LLC, we are a 50 percent beneficial owner with Dynegy of WCP, which owns, operates and markets the power of four California plants. Dynegy and its affiliates and subsidiaries are responsible for gas procurement and marketing and trading activities on behalf of WCP. The complaints primarily allege that the defendants engaged in unfair business practices, price fixing, antitrust violations, and other market "gaming" activities. Certain of these lawsuits, which seek unspecified treble damages and injunctive relief, were consolidated and made a part of a Multi-District Litigation proceeding before the U.S. District Court for the Southern District of California. In December 2002, the district court found that federal jurisdiction was absent and remanded the cases back to state court. On December 8, 2004, the U.S. Court of Appeals for the Ninth Circuit affirmed the district court in most respects. On March 3, 2005, the Ninth Circuit denied a motion for rehearing. On May 5, 2005, the case was remanded to California state court and, under a scheduling order, defendants filed their objections to the pleadings based on the filed rate doctrine and federal preemption. A hearing is scheduled for September 9, 2005, and a decision is expected shortly thereafter. On July 22, 2005, the court dismissed NRG Energy, Inc. without prejudice leaving only subsidiaries of WCP remaining in the case.

In the Northern California cases, on February 25, 2005, the Ninth Circuit affirmed the district court's decision to dismiss all of the defendants' cases.

In the lawsuit brought by the California Attorney General, after removal to federal court, on March 25, 2003, the U.S. District Court for the Northern District of California dismissed the case based upon federal preemption and the filed rate doctrine. On July 6, 2004, the Ninth Circuit affirmed that dismissal and later rejected rehearing. On April 18, 2005, the U.S. Supreme Court denied the Attorney General's petition for writ of certiorari thereby ending the case.

Regarding the remaining case, defendants filed dispositive motions in the fall of 2002. In the first quarter of 2003 the judge granted motions to dismiss in certain of these cases based on federal preemption and the filed rate doctrine. On September 10, 2004, the U.S. Court of Appeals for the Ninth Circuit affirmed the District Court's dismissal. On November 5, 2004, the plaintiffs filed a petition for writ of certiorari with the U.S. Supreme Court which, on June 27, 2005, denied that petition thereby ending the case.

In addition to the cases discussed above, numerous other cases, including putative class actions, have been filed in state and federal court on behalf of business and residential electricity consumers which name us and/or WCP and/or certain subsidiaries of WCP, in addition to numerous other defendants. The complaints allege the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades, and violated California's antitrust law and unfair business practices law. The complaints seek restitution and disgorgement, civil fines, compensatory and punitive damages, attorneys' fees and declaratory and injunctive relief. Motion practice is proceeding in these cases and dispositive motions have been filed in several. In certain of the above referenced cases, Dynegy is defending WCP and/or its subsidiaries pursuant to a limited indemnification agreement while in the others, Dynegy's counsel is representing it and WCP and/or its subsidiaries with each party responsible for half of the costs. Where NRG Energy is named, we are defending the case and bear our own costs of defense.

FERC Proceedings

There are a number of proceedings in which WCP and WCP subsidiaries are parties, which are either pending before FERC or on appeal from FERC to various U.S. Courts of Appeal. These cases involve, among other things, allegations of physical withholding, a FERC-established price mitigation plan determining maximum rates for wholesale power transactions in certain spot markets, and the enforceability of, and obligations under, various contracts with, among others, the California Independent System Operator, the California Department of Water Resources, or CDWR, and the State of California. Among these is a demand by the State of California for FERC to abrogate the CDWR contract between the State and subsidiaries of WCP. In 2003, FERC rejected this demand and denied rehearing. The case was appealed to the U.S. Court of Appeals for the Ninth Circuit where oral argument was held December 8, 2004.

California Attorney General

The California Attorney General has undertaken an investigation entitled "In the Matter of the Investigation of Possibly Unlawful, Unfair, or Anti-Competitive Behavior Affecting Electricity Prices in California". Dynegy, we and subsidiaries of WCP have responded to interrogatories, document requests, and to requests for interviews.

NRG Bankruptcy Cap on California Claims

On November 21, 2003, in conjunction with confirmation of the NRG plan of reorganization, we reached an agreement with the Attorney General and the State of California, generally, whereby for purposes of distributions, if any, to be made to the State of California under the NRG plan of reorganization, the liquidated amount of any and all allowed claims shall not exceed $1.35 billion in the aggregate. The agreement neither affects our right to object to these claims on any and all grounds nor admits any liability whatsoever. We further agreed to waive any objection to the liquidation of these claims in a non-bankruptcy forum having proper jurisdiction.

New York Operating Reserve Markets

Consolidated Edison and others petitioned the U.S. Court of Appeals for the District of Columbia Circuit for review of FERC's refusal to order a re-determination of prices in the New York Independent System Operator, or NYISO, operating reserve markets for a two month period in 2000. On November 7, 2003, the court found that NYISO's method of pricing spinning reserves violated the NYISO tariff. On March 4, 2005, FERC issued an order stating that no refunds would be required for the tariff violation associated with the pricing of spinning reserves. In the order, FERC also stated that the exclusion of the Blenheim-Gilboa facility and western reserves from the non-spinning market was not a market flaw and NYISO was correct not to use its TEP authority to revise the prices in this market. A motion for rehearing of the Order was filed before the April 3, 2005 deadline, and on May 4, 2005, FERC issued an order staying the time period for deciding the motion. If the March 4, 2005 order is reversed and refunds are required, NRG entities which may be affected include NRG Power Marketing, Inc., or PMI, Astoria Gas Turbine Power LLC and Arthur Kill Power LLC. Although non-NRG-related entities would share responsibility for payment of any such refunds, under the petitioners' theory the cumulative exposure to our above-listed entities could exceed $23 million.

Connecticut Congestion Charges

On November 28, 2001, CL&P sought recovery of amounts it claimed was owed for congestion charges. CL&P withheld approximately $30 million from amounts owed to PMI under an October 29, 1999, contract and PMI counterclaimed. CL&P's motion for summary judgment, which PMI opposed, remains pending. We cannot estimate at this time the overall exposure for congestion charges for the term of the contract prior to the implementation of standard market design which occurred on March 1, 2003, however, such amount has been fully reserved as a reduction to outstanding accounts receivable.

New York Environmental Settlement

In January 2002, the New York Department of Environmental Conservation, or NYSDEC, sued Niagara Mohawk Power Corporation, or NiMo, and us in federal court in New York asserting that projects undertaken at our Huntley and Dunkirk plants by NiMo, the former owner of the facilities, violated federal and state laws. On January 11, 2005, we reached an agreement to settle this matter whereby we will reduce levels of sulfur dioxide by over 86 percent and nitrogen oxide by over 80 percent in aggregate at the Huntley and Dunkirk plants. We are not subject to any penalty as a result of the settlement. Through the end of the decade, we expect that our ongoing compliance with the emissions limits set out in the settlement will be achieved through capital expenditures already planned. This includes our conversion to low sulfur western coal at the Huntley and Dunkirk plants that will be completed by spring 2006. On April 6, 2005, NYSDEC filed a motion with the court to enter the Consent Decree and on April 19, 2005, we filed a supporting motion. On June 3, 2005, the U.S. District Court for the Western District of New York entered the Consent Decree permitting the settlement and ending the case.

Station Service Disputes

On October 2, 2000, NiMo commenced an action against us in New York state court seeking damages related to our 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 some or all of the disputes in the action. The potential loss inclusive of amounts paid to NiMo and accrued is approximately $24.4 million. In a companion 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 station obligations over a 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. On April 22, 2005, FERC denied NiMo's motion for rehearing. NiMo appealed to the U.S. Court of Appeals for the D.C. Circuit which, on May 12, 2005, consolidated the appeal with several pending station service disputes involving NiMo.

On December 14, 1999, NRG Energy 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 Energy 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, however, the parties have yet to agree on a description of the dispute and on the appointment of a neutral arbitrator. The potential loss inclusive of amounts paid to CL&P and accrued could exceed $6 million.

U.S. Environmental Protection Agency

On January 27, 2004, our subsidiaries, Louisiana Generating, LLC and Big Cajun II, received an initial and, thereafter, subsequent requests under Section 114 of the federal Clean Air Act from EPA Region 6 seeking information primarily relating to physical changes made at Big Cajun II. Louisiana Generating, LLC and Big Cajun II submitted several responses to the USEPA. On February 15, 2005, Louisiana Generating, LLC received a Notice of Violation alleging violations of the New Source Review provisions of the Clean Air Act at Big Cajun II Units 1 and 2 from 1998 through the Notice of Violation date. On April 7, 2005, a meeting was held with USEPA and the Department of Justice and additional information was provided to the agency.

TermoRio Litigation

TermoRio was a greenfield cogeneration project located in the state of Rio de Janeiro, Brazil. Based on the project's failure to meet certain key milestones, we exercised our rights under the project agreements to sell our debt and equity interests in the project to our partner Petroleo Brasileiro S.A.–Petrobras, or Petrobras. Arbitration ensued, and on March 8, 2003, the arbitral tribunal decided most, but not all, of the issues in our favor and awarded us approximately US $80 million. On June 4, 2004, NRG Energy commenced a lawsuit in the U.S. District Court for the Southern District of New York seeking to enforce the arbitration award. On February 16, 2005, a conditional settlement agreement was signed with Petrobras, whereby Petrobras agreed to pay us $70.8 million. Such payment was received by us at a closing held on February 25, 2005. As of December 31, 2004, we had a note receivable from Petrobras of $57.3 million related to the arbitral award. The amounts paid in excess of the $57.3 million were recognized in earnings within other income in the first quarter of 2005 as the settlement was accounted for as a gain contingency. In addition to the settlement figure, we have the right to continue to seek recovery of $12.3 million that is currently being held by Petrobras pending a ruling in a related dispute with a third-party. This related dispute is also being accounted for as a gain contingency.

Itiquira Energetica, S.A.

Our Brazilian project company, Itiquira Energetica S.A., the owner of a 156 MW hydro project in Brazil, is in arbitration with the former EPC contractor for the project, Inepar Industria e Construcoes, or Inepar. The dispute was commenced by Itiquira in September of 2002 and pertains to certain matters arising under the EPC contract. Itiquira seeks $R 140 million (approximately US $33 million) and asserts that Inepar breached the contract. Inepar seeks $R 39 million (approximately US $9 million) and alleges that Itiquira breached the contract. Final written arguments were submitted on January 28, 2005, to the court of arbitration. On June 24, 2005 the court of arbitration postponed its decision and instead set forth additional questions to be answered by appointed experts with associated submittals by both parties. A decision is now expected by the end of 2005.

CFTC Trading Litigation

On July 1, 2004, the CFTC filed a civil complaint against us in Minnesota federal district court, alleging false reporting of natural gas trades from August 2001 to May 2002, and seeking an injunction against future violations of the Commodity Exchange Act. On November 17, 2004, a Bankruptcy Court hearing was held on the CFTC's motion to reinstate its expunged bankruptcy claim, and on our motion to enforce the provisions of the NRG plan of reorganization thereby precluding the CFTC from continuing its federal court action. The bankruptcy court has not yet ruled on those motions. On December 6, 2004, a federal magistrate judge issued a report and recommendation that our motion to dismiss be granted. That motion to dismiss was granted by the federal district court in Minnesota on March 16, 2005. On May 16, 2005 the CFTC filed a notice of appeal with the U.S. Court of Appeals of the Eighth Circuit. Briefing on the appeal is set to close by the end of the third quarter of 2005. The Bankruptcy Court has yet to schedule a hearing or rule on the CFTC's pending motion to reinstate its expunged claim.

Disputed Claims Reserve

As part of the NRG plan of reorganization confirmed on November 24, 2003, we have 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, to the extent such claims are resolved now that we have emerged from bankruptcy, the claimants will be paid from the reserve on the same basis as if they had been paid out in the bankruptcy. That means that their allowed claims will be reduced to the same recovery percentage as other creditors would have received and will be paid in pro rata distributions of cash and common stock. We believe we have funded the disputed claims reserve at a sufficient level to settle the remaining unresolved proofs of claim we received during the bankruptcy proceedings. However, to the extent the aggregate amount of these payouts of disputed claims ultimately exceeds the amount of the funded claims reserve, we are obligated to provide additional cash, notes and common stock to the claimants. We will continue to monitor our obligation as the disputed claims are settled. If excess funds remain in the disputed claims reserve after payment of all obligations, such amounts will be reallocated to the creditor pool. We have contributed common stock and cash to an escrow agent to complete the distribution and settlement process. Since we have surrendered control over the common stock and cash provided to the disputed claims reserve, we recognized the issuance of the common stock as of December 6, 2003 and removed the cash amounts from our balance sheet. Similarly, we removed the obligations relevant to the claims from our balance sheet when the common stock was issued and cash contributed.

Environmental Matters

We are subject to a broad range of foreign, federal, state and local environmental and safety laws and regulations in the development, ownership, construction and operation of our domestic and international projects. These laws and regulations impose requirements on discharges of substances to the air, water and land, the handling, storage and disposal of, and exposure to, hazardous substances and wastes and the cleanup of properties affected by pollutants. These laws and regulations generally require that we obtain governmental permits and approvals before construction or operation of a power plant commences, and after completion, that our facilities operate in compliance with those permits and applicable legal requirements. We could also be held responsible under these laws for the cleanup of pollutants released at our facilities or at off-site locations where we may have sent wastes, even if the release or off-site disposal was conducted in compliance with the law.

Northeast Region

Significant amounts of ash are contained in landfills at on and off-site locations. At Dunkirk, Huntley, Somerset and Indian River, ash is disposed at landfills owned and operated by the Company. The Company maintains financial assurance to cover costs associated with closure, post-closure care and monitoring activities. The Company has funded a trust in the amount of approximately $6.0 million to provide such financial assurance in New York and $6.8 million in Delaware. The Company must also maintain financial assurance for closing interim status "RCRA facilities" at the Devon, Middletown, Montville and Norwalk Harbor Generating Stations and has funded a trust in the amount of $1.5 million accordingly.

The Company inherited historical clean-up liabilities when it acquired the Somerset, Devon, Middletown, Montville, Norwalk Harbor, Arthur Kill and Astoria Generating Stations. During installation of a sound wall at Somerset Station in 2003, oil contaminated soil was encountered. The Company has delineated the general extent of contamination, determined it to be minimal, and has placed an activity use limitation on that section of the property. Site contamination liabilities arising under the Connecticut Transfer Act at the Devon, Middletown, Montville and Norwalk Harbor Stations have been identified. The Company has proposed a remedial action plan to be implemented over the next two to eight years (depending on the station) to address historical ash contamination at the facilities. The total estimated cost is not expected to exceed $1.5 million. Remedial obligations at the Arthur Kill generating station have been established in discussions between the Company and the NYSDEC and are estimated to cost approximately $1 million. Remedial investigations continue at the Astoria generating station with long-term clean-up liability expected to be approximately $2.9 million. While installing groundwater-monitoring wells at Astoria to track our remediation of a historical fuel oil spill, the drilling contractor encountered deposits of coal tar in two borings. The Company reported the coal tar discovery to the NYSDEC in 2003 and delineated the extent of this contamination. The Company may also be required to remediate the coal tar contamination and/or record a deed restriction on the property if significant contamination is to remain in place.

At the end of 2004, we estimated environmental capital expenditures of approximately $200 million for our 2005 through 2010 plan, at the facilities in New York, Connecticut, Delaware and Massachusetts. These expenditures are primarily related to installation of particulate SO_2 and NO_X controls, as well as installation of "Best Technology Available", or BTA, under the Phase II 316(b) Rule.

Huntley Power LLC, Dunkirk Power LLC and Oswego Power LLC were issued Notices of Violation for opacity exceedances and entered into a Consent Order with NYSDEC, effective March 31, 2004. The Consent Order required the respondents to pay a civil penalty of $1.0 million which was paid in April 2004. The Order also establishes stipulated penalties (payable quarterly) for future violations of opacity requirements and a compliance schedule. The Company is currently in dispute with NYSDEC over the method of calculation for stipulated penalties. The Company has reserved $1.4 million as of June 30, 2005, and does not believe that the final resolution will involve a material larger amount.

South Central Region

Liabilities associated with closure, post-closure care and monitoring of the ash ponds owned and operated on site at the Big Cajun II Generating Station are addressed through the use of a trust fund maintained by the Company in the amount of approximately $5.9 million. Annual payments are made to the fund in the amount of approximately $116,000.

At the end of 2004, we estimated environmental capital expenditures of approximately $200 million for our 2005 through 2010 plan, at our South Central facilities. These expenditures are primarily related to installation of particulate SO_2 and NO_X controls, as well as installation of BTA, under the Phase II 316(b) Rule.

Western Region

The Asset Purchase Agreements for the Long Beach, El Segundo, Encina, and San Diego gas turbine generating facilities provide that SCE and SDG&E retain liability, and indemnify the Company, for existing soil and groundwater contamination that exceeds remedial thresholds in place at the time of closing. The Company and its business partner conducted Phase I and Phase II Environmental Site Assessments at each of these sites for purposes of identifying such existing contamination and provided the results to the sellers. SCE and SDG&E have agreed to address contamination identified by these studies and are undertaking corrective action at the Encina and San Diego gas turbine generating sites. Spills and releases of various substances have occurred at these sites since the Company established the historical baseline, all of which have been, or will be, completely remediated. An oil leak in 2002 from underground piping at the El Segundo Generating Station contaminated soils adjacent to and underneath the Unit 1 and 2 powerhouse. The Company excavated and disposed of contaminated soils that could be removed in accordance with existing laws. Following the Company's formal request, the LARWQCB will allow contaminated soils to remain underneath the building foundation until the building is demolished.

Regulatory Matters

NYISO Claims

In November 2002, NYISO notified us of claims related to New York City mitigation adjustments, general NYISO billing adjustments and other miscellaneous charges related to sales between November 2000 and October 2002. New York City mitigation adjustments totaled $11.4 million. The issue related to NYISO's concern that NRG would not have sufficient revenue to cover subsequent revisions to its energy market settlements. As of June 30, 2005, NYISO held $3.9 million in escrow for such future settlement revisions.

Commitments

We have a number of commercial commitments as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2004. During the current period we have increased our commitments as described below.

In August 2004, we entered into a contract to purchase 1,540 aluminum railcars from Freight Car America, formerly Johnstown America Corporation, to be used for the transportation of low sulfur coal from Wyoming to NRG's coal burning generating plants, including our New York and South Central facilities. On February 18, 2005, we entered into a ten-year operating lease agreement with GE Railcar Services Corporation, or GE, for the lease of 1,500 railcars. Delivery of the railcars from Freight Car America commenced in February 2005 and is expected to be completed by August 2005. We have assigned certain of our rights and obligations for 1,500 railcars under the purchase agreement with Freight Car America to GE. Accordingly, the railcars which we lease from GE under the arrangement described above will be purchased by GE from Freight Car America in lieu of our purchase of those railcars.

In December 2004, we entered into a long-term coal transport agreement with the Burlington Northern and Santa Fe Railway Company and affiliates of American Commercial Lines LLC to deliver low sulfur coal to our Big Cajun II facility in New Roads, Louisiana beginning April 1, 2005. In March 2005, we entered into an agreement to purchase coal over a period of four years and nine months from Buckskin Mining Company, or Buckskin. The coal will be sourced from Buckskin's mine in the Powder River Basin, Wyoming, and will be used primarily in NRG's coal-burning generation plants in the South Central region of the United States. Including this contract and other contracts, total coal purchase obligations increased by $174.4 million, which are expected to be paid over the course of the next two years.

In April 2005, we amended our contract for a five-year coal rail transportation agreement with CSX Transportation, Inc. and Union Pacific Railroad Company, to deliver low sulfur coal to our Dunkirk and Huntley facilities in Buffalo, New York, beginning April 1, 2005. Although the amendment does not change our minimum financial commitments, we are now obligated to transport at least 95% of our coal supplies for our Dunkirk and Huntley facilities with CSX Transportation, Inc. and Union Pacific Railroad Company.

Note 14 — Guarantees

In November 2002, the FASB issued FASB Interpretation No. 45, *"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."* In connection with the adoption of Fresh Start, all outstanding guarantees were considered new; accordingly, we applied the provisions of FIN 45 to all of the guarantees.

The descriptions below update, and should be read in conjunction with, the complete descriptions under Note 29, *Guarantees and Other Contingent Liabilities,* in NRG Energy's Form 10-K for the year ended December 31, 2004.

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

On February 28, 2005, concurrent with the amendment of its debt facility, our Flinders subsidiary issued, under its amended AUD 20.0 million (US $15.6 million) working capital and performance bond facility sponsored by National Australia Bank Limited, an AUD 15.5 million (US $11.8 million) indemnity to the Australia and New Zealand Banking Group Limited (ANZ), the previous sponsor of the facility. This indemnified ANZ against potential claims for performance bonds or letters of credit issued under the facility prior to February 28, 2005. The indemnity was canceled on May 17, 2005. As of June 30, 2005 Flinders' had AUD 14.0 million (US $10.6 million) in performance bonds and letters of credit under the new facility.

On February 18, 2005, we issued a guarantee to the benefit of General Electric Railcar Service Corporation. We guarantee the performance and payment obligations of PMI under a railcar lease from GE as described in Note 13, *Commitments and Contingencies*. Payment obligations include future rental and termination payments, which are estimated to total $58.6 million over the first five years of the lease, and $49.9 million over the last five years of the lease, should we elect not to exercise our termination rights. However, our obligations under this guarantee include additional requirements that would be difficult to quantify until such time as a claim was made. As a result, our maximum potential obligation under this guarantee is indeterminate. At this time, we do not anticipate that we will be required to perform under this guarantee.

Also during the six months ended June 30, 2005, we issued guarantees of the performance of PMI under various agreements with counter-parties for the purchase and sale of fuel, emission credits and power generation products. These new guarantees total $32.8 million. At this time, we do not believe we will be obligated to perform under these guarantees.

At June 30, 2005, we were contingently obligated for approximately $178.5 million under our funded standby letters of credit facility, and we had $16.1 million issued under an unfunded standby letter of credit facility. Obligations of the unfunded letter of credit facility were reserved through our bankruptcy restructuring. Most of these standby letters of credit are issued in support of our obligations to perform under commodity agreements, financing or other arrangements. These letters of credit expire within one year of issuance, and it is typical for us to renew many of them on similar terms.

On April 1, 2005, in conjunction with the sale of our interest in the Enfield Energy Center Ltd, a minority-owned, indirectly held affiliate of ours, we issued a guarantee of the obligations of an affiliate of ours under the sale and purchase agreement, to the buyers of our interest. Our maximum liability for this guarantee is $55.6 million. We do not anticipate that we will be required to perform under this guarantee.

Because many of the guarantees and indemnities we issue to third parties do not limit the amount or duration of our obligations to perform under them, there exists a risk that we may have obligations in excess of the amounts described above. For those guarantees and indemnities that do not limit our liability exposure, we may not be able to estimate what our liability would be, until a claim was made for payment or performance, due to the contingent nature of these contracts.

Note 15 – Subsequent Events

NRG has committed to repurchase, on August 11, 2005, $250 million of NRG's outstanding common stock from an affiliate of Credit Suisse First Boston LLC, or CSFB. NRG will fund the planned repurchase with existing cash balances. To enable this share repurchase under NRG's high yield debt indenture, NRG will issue simultaneously in a private transaction, $250 million of perpetual preferred stock. On August 5, 2005, NRG obtained an amendment to its corporate credit agreement which allowed NRG to use cash proceeds from the preferred issuance to repurchase approximately $229 million of our 8% high yield notes at 108% of par.

Note 16 — Condensed Consolidating Financial Information

As of June 30, 2005, we have $1.35 billion of 8% Second Priority Senior Secured Notes outstanding. These notes are guaranteed by each of our current and future wholly-owned domestic subsidiaries, or Guarantor Subsidiaries. Each of the following Guarantor Subsidiaries fully and unconditionally guarantee the Notes.

Arthur Kill Power LLC
Astoria Gas Turbine Power LLC
Berrians I Gas Turbine Power LLC
Big Cajun II Unit 4 LLC
Capistrano Cogeneration Company
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 II LLC
Hanover Energy Company
Huntley Power LLC
Indian River Operations Inc.
Indian River Power LLC
James River Power LLC
Kaufman Cogen LP
Keystone Power LLC
Louisiana Generating LLC
Middletown Power LLC
Montville Power LLC
NEO California Power LLC
NEO Chester-Gen LLC
NEO Corporation
NEO Freehold-Gen LLC
NEO Landfill Gas Holdings Inc.
NEO Power Services Inc.
NRG Cadillac Operations Inc.
NRG California Peaker Operations LLC
NRG Connecticut Affiliate Services Inc.
NRG Devon Operations Inc.
NRG Dunkirk Operations Inc.
NRG El Segundo Operations Inc.
NRG Huntley Operations Inc.
NRG International LLC
NRG Kaufman LLC
NRG Mesquite LLC
NRG MidAtlantic Affiliate Services Inc.
NRG MidAtlantic Generating LLC
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 Northeast Generating LLC
NRG Norwalk Harbor Operations Inc.
NRG Operating Services, Inc.
NRG Oswego Harbor Power Operations Inc.
NRG Power Marketing Inc.
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 West Coast LLC

Norwalk Power LLC	NRG Western Affiliate Services Inc.
NRG Affiliate Services Inc.	Oswego Harbor Power LLC
NRG Arthur Kill Operations Inc.	Saguaro Power LLC
NRG Asia-Pacific, Ltd.	Somerset Operations Inc.
NRG Astoria Gas Turbine Operations, Inc.	Somerset Power LLC
NRG Bayou Cove LLC	Vienna Operations Inc.
NRG Cabrillo Power Operations Inc.	Vienna Power LLC

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

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

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

NRG Energy, Inc. and Subsidiaries

Condensed Consolidating Statements of Operations
For the Three Months Ended June 30, 2005
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$ 428,562	$ 142,122	$ 15,302	$ (1,419)	$ 584,567
Operating Costs and Expenses					
Cost of majority-owned operations	323,927	104,945	9,017	(1,419)	436,470
Depreciation and amortization	33,192	12,443	2,114	—	47,749
General, administrative and development	12,113	6,233	34,818	—	53,164
Corporate relocation charges	—	—	456	—	456
Impairment charges	223	—	—	—	223
Total operating costs and expenses	369,455	123,621	46,405	(1,419)	538,062
Operating Income/(Loss)	59,107	18,501	(31,103)	—	46,505
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	(407)	—	—	(407)
Equity in earnings of consolidated subsidiaries	23,022	—	74,061	(97,083)	—
Equity in earnings of unconsolidated affiliates	9,060	7,408	(8)	—	16,460
Write downs and gains/(losses) on sales of equity method investments	—	11,561	—	—	11,561
Other income, net	2,343	13,347	2,109	(10,145)	7,654
Refinancing Expense	—	—	—	—	—
Interest expense	(110)	(24,014)	(36,581)	10,145	(50,560)
Total other income/(expense)	34,315	7,895	39,581	(97,083)	(15,292)
Income From Continuing Operations Before Income Taxes	93,422	26,396	8,478	(97,083)	31,213
Income Tax Expense/(Benefit)	24,183	(714)	(15,388)	—	8,081
Income From Continuing Operations	69,239	27,110	23,866	(97,083)	23,132
Income on Discontinued Operations, net of Income Taxes	—	734	—	—	734
Net Income	$ 69,239	$ 27,844	$ 23,866	$ (97,083)	$ 23,866

(1) 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, 2005
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$ 880,155	$ 280,298	$ 28,109	$ (2,853)	$ 1,185,709
Operating Costs and Expenses					
Cost of majority-owned operations	662,375	211,910	17,960	(2,853)	889,392
Depreciation and amortization	66,468	25,282	4,423	—	96,173
General, administrative and development	22,678	14,900	65,480	—	103,058
Corporate relocation charges	—	—	3,911	—	3,911
Impairment charges	223	—	—	—	223
Total operating costs and expenses	751,744	252,092	91,774	(2,853)	1,092,757
Operating Income/(Loss)	128,411	28,206	(63,665)	—	92,952
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	(881)	—	—	(881)
Equity in earnings of consolidated subsidiaries	68,219	—	153,261	(221,480)	—
Equity in earnings of unconsolidated affiliates	16,041	37,372	11	—	53,424
Write downs and gains/(losses) on sales of equity method investments	—	11,561	—	—	11,561
Other income, net	2,928	35,519	4,915	(10,206)	33,156
Refinancing expense	—	9,783	(34,807)	—	(25,024)
Interest expense	(231)	(40,266)	(76,260)	10,206	(106,551)
Total other income (expense)	86,957	53,088	47,120	(221,480)	(34,315)
Income From Continuing Operations Before Income Taxes	215,368	81,294	(16,545)	(221,480)	58,637
Income Tax Expense/(Benefit)	69,691	6,221	(63,029)	—	12,883
Income From Continuing Operations	145,677	75,073	46,484	(221,480)	45,754
Income on Discontinued Operations, net of Income Taxes	—	730	—	—	730
Net Income	$ 145,677	$ 75,803	$ 46,484	$ (221,480)	$ 46,484

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

NRG Energy, Inc. and Subsidiaries

Condensed Consolidating Balance Sheet
June 30, 2005
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy	Eliminations(1)	Consolidated Balance
			(In thousands)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ 293,944	$ 381,033	$ 148,184	$ —	$ 823,161
Restricted cash	3,742	83,506	—	—	87,248
Accounts receivable, net	157,205	251,188	(94,765)	32	313,660
Current portion of notes receivable	—	24,800	108,870	(108,570)	25,100
Income taxes receivable	(49)	2	38,924	—	38,877
Inventory	198,650	28,845	1,500	—	228,995
Derivative instruments valuation	34,448	19,878	5,198	—	59,524
Prepayments and other current assets	236,048	19,349	38,847	(182)	294,062
Deferred income taxes	19,463	8	(19,465)	1,256	1,262
Total current assets	943,451	808,609	227,293	(107,464)	1,871,889
Net property, plant and equipment	2,207,153	1,073,874	27,428	195	3,308,650
Other Assets					
Investment in subsidiaries	789,137	—	4,053,000	(4,842,137)	—
Equity investments in affiliates	289,364	348,095	422	—	637,881
Notes receivable, less current portion	405,049	720,950	977	(403,515)	723,461
Intangible assets, net	249,828	26,026	—	—	275,854
Derivative instruments valuation	3,327	10,088	—	—	13,415
Funded letter of credit	—	—	350,000	—	350,000
Other non-current assets	36,777	20,282	43,455	—	100,514
Total other assets	1,773,482	1,125,441	4,447,854	(5,245,652)	2,101,125
Total Assets	$ 4,924,086	$ 3,007,924	$ 4,702,575	$ (5,352,921)	$ 7,281,664
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt	$ 100,317	$ 84,989	$ 14,009	$ (108,570)	$ 90,745
Accounts payable	214,134	80,558	(144,004)	—	150,688
Derivative instruments valuation	113,544	16,079	—	—	129,623
Other bankruptcy settlement	—	177,424	—	—	177,424
Accrued expenses and other current liabilities	139,584	59,803	38,698	(182)	237,903
Total current liabilities	567,579	418,853	(91,297)	(108,752)	786,383
Other Liabilities					
Long-term debt and capital leases	193	1,409,655	2,113,873	(403,515)	3,120,206
Deferred income taxes	(56,307)	108,633	55,856	1,256	109,438
Derivative instruments valuation	32,848	113,550	7,066	—	153,464
Out-of-market contracts	309,129	—	—	—	309,129
Other non-current liabilities	128,941	49,942	16,426	—	195,309
Total non-current liabilities	414,804	1,681,780	2,193,221	(402,259)	3,887,546
Total liabilities	982,383	2,100,633	2,101,924	(511,011)	4,673,929
Minority interest	—	7,084	—	—	7,084
Stockholders' Equity	3,941,703	900,207	2,600,651	(4,841,910)	2,600,651
Total Liabilities and Stockholders' Equity	$ 4,924,086	$ 3,007,924	$ 4,702,575	$ (5,352,921)	$ 7,281,664

(1) 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, 2005
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income	$ 145,677	$ 75,803	$ 46,484	$ (221,480)	$ 46,484
Adjustments to reconcile net income to net cash provided (used) by operating activities					
Distributions in excess of (less than) equity in earnings of unconsolidated affiliates and consolidated subsidiaries	(30,158)	(22,185)	12,588	55,680	15,925
Depreciation and amortization	66,468	25,282	4,423	—	96,173
Reserve for note and interest receivable	—	(98)	—	—	(98)
Amortization of financing costs and debt premium	—	3,052	1,906	—	4,958
Write-off of deferred financing costs and debt premium	—	(9,783)	1,370	—	(8,413)
Write downs and gains/losses on sale of equity method investments	—	(11,561)	—	—	(11,561)
Deferred income taxes	(43,651)	(2,112)	42,138	—	(3,625)
Unrealized (gains)/losses on derivatives	70,503	11,444	(86,376)	86,139	81,710
Asset impairment	—	223	—	—	223
Minority interest	—	881	—	—	881
Amortization of power contracts and emission credits	10,277	4,863	—	—	15,140
Amortization of unearned equity compensation	1,065	183	3,470	—	4,718
Gain on TermoRio settlement	—	(13,532)	—	—	(13,532)
Cash used by changes in working capital, net of disposition affects	(5,888)	13,099	(58,536)	(86,139)	(137,464)
Net Cash Provided/(used) by Operating Activities	214,293	75,559	(32,533)	(165,800)	91,519
Cash Flows from Investing Activities					
Proceeds on sale of equity method investments	—	64,575	—	—	64,575
Decrease/(increase) in restricted cash and trust funds	(22)	26,335	—	—	26,313
Decrease/(increase) in notes receivable	3,649	79,486	(103,088)	112,857	92,904
Capital expenditures	(30,063)	(5,403)	(1,071)	—	(36,537)
Return of capital from equity investments	—	1,291	—	—	1,291
Net Cash Provided/(used) by Investing Activities	(26,436)	166,284	(104,159)	112,857	148,546
Cash Flows from Financing Activities					
Proceeds from issuance of long-term debt, net	100,300	216,679	19	(112,857)	204,141
Payments for dividends	(150,000)	(15,800)	(8,072)	165,800	(8,072)
Deferred debt issuance costs	—	(1,076)	(506)	—	(1,582)
Payment for preferred share issuance costs	—	—	(204)	—	(204)
Principal payments on short and long-term debt	(8)	(303,452)	(418,088)	—	(721,548)
Net Cash Used by Financing Activities	(49,708)	(103,649)	(426,851)	52,943	(527,265)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	(1,369)	—	—	(1,369)
Change in Cash from Discontinued Operations	—	1,685	—	—	1,685
Change in cash and cash equivalents	138,149	138,510	(563,543)	—	(286,884)
Cash and Cash Equivalents at Beginning of Period	155,795	242,523	711,727	—	1,110,045
Cash and Cash Equivalents at End of Period	$ 293,944	$ 381,033	$ 148,184	$ —	$ 823,161

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

NRG Energy, Inc. and Subsidiaries

Condensed Consolidating Balance Sheet
December 31, 2004

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ 155,795	$ 242,523	$ 711,727	$ —	$ 1,110,045
Restricted cash	3,720	109,104	—	—	112,824
Accounts receivable, net	182,340	82,757	7,004	—	272,101
Current portion of notes receivable and other investments – affiliates	—	(2,986)	5,482	(2,496)	—
Current portion of notes receivable and other investments	—	85,147	300	—	85,447
Taxes receivable	1	(5,498)	42,981	—	37,484
Inventory	216,932	29,617	1,461	—	248,010
Derivative instruments valuation	79,759	—	—	—	79,759
Prepayments and other current assets	103,891	25,740	42,893	(2,916)	169,608
Current assets — discontinued operations	(88)	3,098	—	—	3,010
Total current assets	742,350	569,502	811,848	(5,412)	2,118,288
Net property, plant and equipment	2,243,558	1,100,017	30,780	196	3,374,551
Other Assets					
Investment in subsidiaries	776,922	—	3,916,352	(4,693,274)	—
Equity investments in affiliates	327,425	407,054	471	—	734,950
Notes receivable, less current portion	408,698	1,037,428	977	(642,581)	804,522
Intangible assets, net	256,392	37,958	—	—	294,350
Derivative instruments valuation	1,468	34,926	5,393	—	41,787
Funded letter of credit	—	—	350,000	—	350,000
Other non-current assets	36,406	21,843	53,331	—	111,580
Total other assets	1,807,311	1,539,209	4,326,524	(5,335,855)	2,337,189
Total Assets	$ 4,793,219	$ 3,208,728	$ 5,169,152	$ (5,341,071)	$ 7,830,028
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt	$ 16	$ 98,877	$ 415,855	$ (2,496)	$ 512,252
Accounts payable	403,433	(37,922)	(194,706)	917	171,722
Derivative instruments valuation	16,772	—	—	—	16,772
Current deferred income taxes	260	92	(18)	—	334
Other bankruptcy settlement	—	175,576	—	—	175,576
Accrued expenses and other current liabilities	124,862	37,926	50,051	(2,916)	209,923
Current liabilities — discontinued operations	—	1,362	—	—	1,362
Total current liabilities	545,343	275,911	271,182	(4,495)	1,087,941
Other Liabilities					
Long-term debt	202	1,768,068	2,128,177	(642,581)	3,253,866
Deferred income taxes	(32,379)	130,972	35,732	—	134,325
Derivative instruments valuation	172	132,209	16,064	—	148,445
Out-of-market contracts	318,664	—	—	—	318,664
Other non-current liabilities	121,735	39,870	25,833	—	187,438
Non-current liabilities — discontinued operations	—	1,081	—	—	1,081
Total non-current liabilities	408,394	2,072,200	2,205,806	(642,581)	4,043,819
Total liabilities	953,737	2,348,111	2,476,988	(647,076)	5,131,760
Minority interest	—	6,104	—	—	6,104
Stockholders' Equity	3,839,482	854,513	2,692,164	(4,693,995)	2,692,164
Total Liabilities and Stockholders' Equity	$ 4,793,219	$ 3,208,728	$ 5,169,152	$ (5,341,071)	$ 7,830,028

(1) 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, 2004
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$ 421,736	$ 139,946	$ 14,019	$ (2,078)	$ 573,623
Operating Costs and Expenses					
Cost of majority-owned operations	247,968	99,746	7,622	(2,078)	353,258
Depreciation and amortization	31,494	17,865	3,809	—	53,168
General, administrative and development	23,863	11,816	10,076	(9)	45,746
Corporate relocation charges	1	—	5,644	—	5,645
Reorganization charges	(570)	1	(2,092)	—	(2,661)
Impairment charges	1,676	—	—	—	1,676
Total operating costs and expenses	304,432	129,428	25,059	(2,087)	456,832
Operating Income/(Loss)	117,304	10,518	(11,040)	9	116,791
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	(201)	—	—	(201)
Equity in earnings of consolidated subsidiaries	25,350	—	99,392	(124,742)	—
Equity in earnings of unconsolidated affiliates	26,143	19,942	16	—	46,101
Write downs and losses on sales of equity method investments	—	702	503	—	1,205
Other income, net	2,956	4,594	2,246	(1,745)	8,051
Interest expense	(127)	(22,812)	(45,022)	1,736	(66,225)
Total other income (expense)	54,322	2,225	57,135	(124,751)	(11,069)
Loss From Continuing Operations Before Income Taxes	171,626	12,743	46,095	(124,742)	105,722
Income Tax Expense/(Benefit)	68,514	5,037	(37,229)	—	36,322
Gain From Continuing Operations	103,112	7,706	83,324	(124,742)	69,400
Income/(Loss) on Discontinued Operations, net of Income Taxes	(132)	14,056	(300)	—	13,624
Net Income	$ 102,980	$ 21,762	$ 83,024	$ (124,742)	$ 83,024

(1) 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, 2004
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$ 848,232	$ 303,380	$ 26,026	$ (3,750)	$ 1,173,888
Operating Costs and Expenses					
Cost of majority-owned operations	519,955	203,520	15,286	(3,750)	735,011
Depreciation and amortization	66,389	35,284	6,501	—	108,174
General, administrative and development	43,685	14,785	23,663	5	82,138
Corporate relocation charges	1	—	6,760	—	6,761
Reorganization charges	1,163	151	2,275	—	3,589
Impairment charges	1,676	—	—	—	1,676
Total operating costs and expenses	632,869	253,740	54,485	(3,745)	937,349
Operating Income/(Loss)	215,363	49,640	(28,459)	(5)	236,539
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	(709)	—	—	(709)
Equity in earnings of consolidated subsidiaries	46,936	—	157,221	(204,157)	—
Equity in earnings/(losses) of unconsolidated affiliates	33,871	30,752	(809)	—	63,814
Write downs and gains/(losses) on sales of equity method investments	—	(1,271)	738	—	(533)
Other income, net	3,658	12,043	3,024	(7,017)	11,708
Refinancing expense	—	—	(30,417)	—	(30,417)
Interest expense	587	(48,252)	(88,311)	7,022	(128,954)
Total other income (expense)	85,052	(7,437)	41,446	(204,152)	(85,091)
Gain From Continuing Operations Before Income Taxes	300,415	42,203	12,987	(204,157)	151,448
Income Tax Expense/(Benefit)	139,481	11,693	(100,572)	—	50,602
Gain From Continuing Operations	160,934	30,510	113,559	(204,157)	100,846
Income/(Loss) on Discontinued Operations, net of Income Taxes	(204)	12,917	(300)	—	12,413
Net Income	$ 160,730	$ 43,427	$ 113,259	$ (204,157)	$ 113,259

(1) 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, 2004
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income	160,730	43,427	113,259	(204,157)	113,259
Adjustments to reconcile net income to net cash provided by operating activities					
Distributions in excess of (less than) equity in earnings of unconsolidated affiliates and consolidated subsidiaries	(16,246)	(26,863)	(81,597)	129,457	4,751
Depreciation and amortization	66,389	40,609	6,501	—	113,499
Amortization of debt issuance costs and debt discount	—	12,932	3,611	—	16,543
Write off of deferred finance cost due to refinancing	—	—	15,312	—	15,312
Write downs and (gain)/loss on sales of equity method investments	—	1,268	(735)	—	533
Deferred income taxes	(78,372)	5,653	200,943	(78,840)	49,384
Unrealized (gains)/losses on derivatives	(7,018)	(30,791)	18,950	(2,599)	(21,458)
Minority interest	—	2,089	—	—	2,089
Amortization of power contracts and emission credits	11,705	22,812	—	—	34,517
Asset impairment	1,676	—	—	—	1,676
Gain on sale of discontinued operations	—	(13,012)	—	—	(13,012)
Amortization of unearned equity compensation	910	137	6,275	—	7,322
Cash provided (used) by changes in working capital items, net of disposition affects	(87,032)	860	81,675	(2,561)	(7,058)
Net Cash Provided by Operating Activities	52,742	59,121	364,194	(158,700)	317,357
Cash Flows from Investing Activities					
Proceeds on sale of discontinued operations	—	59,190	—	—	59,190
Proceeds on sale of equity method investments	—	26,693	3,000	—	29,693
Increase in restricted cash and trust funds	(11,375)	(25,916)		—	(37,291)
Decrease in note receivable, net	(34,312)	16,521	22,296	10,703	15,208
Investments in equity method investments and projects	(566)	—		—	(566)
Capital expenditures	(43,886)	(19,836)	(954)	—	(64,676)
Investment in subsidiaries	—	—	(92,000)	92,000	—
Net Cash Provided/(Used) by Investing Activities	(90,139)	56,652	(67,658)	102,703	1,558
Cash Flows from Financing Activities					
Proceeds from issuance of long-term debt	—	15,631	475,000	—	490,631
Deferred debt issuance costs	—	53	(8,550)	—	(8,497)
Principal payments on long-term debt	(28,007)	(106,114)	(506,982)	73,297	(567,806)
Dividends to parent	(54,700)	(20,000)	—	74,700	—
Capital contributions from parent	92,000	—	—	(92,000)	—
Net Cash Used/(Provided) by Financing Activities	9,293	(110,430)	(40,532)	55,997	(85,672)
Change in Cash from Discontinued Operations	—	10,822	—	—	10,822
Effect of Exchange Rate Changes on cash and cash equivalents	—	25,588	—	—	25,588
Change in cash and cash equivalents	(28,104)	41,753	256,004	—	269,653
Cash and cash equivalents at Beginning of Period	295,509	160,434	95,280	—	551,223
Cash and cash equivalents at End of Period	$ 267,405	$ 202,187	$ 351,284	$ —	$ 820,876

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

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

NRG Energy, Inc., or "NRG Energy", the "Company", "we", "our", or "us", is a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities, the transacting in and trading of fuel and transportation services and the marketing and trading of energy, capacity and related products in the United States and internationally. We have a diverse portfolio of electric generation facilities in terms of geography, fuel type and dispatch levels. Our principal domestic generation assets consist of a diversified mix of natural gas-, coal- and oil-fired facilities, representing approximately 40%, 31% and 29% of our total domestic generation capacity, respectively. In addition, 23% of our domestic generating facilities have dual- or multiple-fuel capacity, which render the ability for plants to dispatch with the lowest cost fuel option.

Our two principal operating objectives are to optimize performance of our entire portfolio, and to protect and enhance the market value of our physical and contractual assets through the execution of asset-based risk management, marketing and trading strategies within well-defined risk and liquidity guidelines. We manage the assets in our core regions on a portfolio basis as integrated businesses in order to maximize profits and minimize risk. Our business involves the reinvestment of capital in our existing assets for reasons of repowering, expansion, environmental remediation, operating efficiency, reliability programs, greater fuel optionality, greater merit order diversity, enhanced portfolio effect, among other reasons. Our business also may involve acquisitions intended to complement the asset portfolios in our core regions, and from time to time we may also consider and undertake other merger and acquisition transactions that are consistent with our strategy.

We seek to maximize operating income through the generation of energy, marketing and trading of energy, trading of emissions credits, capacity and ancillary services into spot, intermediate and long-term markets and the effective transacting in and trading of fuel supplies and transportation-related services. We perform our own power marketing (except with respect to our West Coast Power and Rocky Road affiliates), which is focused on maximizing the value of our North American and Australian assets through the pursuit of asset-focused power and fuel marketing and, trading activities in the spot, intermediate and long-term markets. We also seek to manage and mitigate commodity market risk, reduce cash flow volatility over time, realize the full market value of the asset base, and add incremental value by using market knowledge to effectively trade positions associated with our asset portfolio. Additionally, we work with independent system operators, regional transmission organizations, regulators and market participants to promote market designs that provide adequate long-term compensation for existing generation assets and to attract the investment required to meet future generation and reliability needs.

As of June 30, 2005, we owned interests in 50 power projects in four countries having an aggregate net generation capacity of approximately 15,057 MW. Approximately 7,900 MW of our capacity consists of power plants in the Northeast region of the United States. Certain of these assets are located in transmission constrained areas, including approximately 1,400 MW of "in-city" New York City generation capacity and approximately 750 MW of southwest Connecticut generation capacity. We own approximately 2,500 MW of generating capacity in the South Central region of the United States, with approximately 2,150 MW of that capacity supported by long-term power purchase agreements.

As of June 30, 2005, our assets in the Western region of the United States consisted of approximately 1,050 MW of capacity with the majority of such capacity owned via our 50% interest in West Coast Power LLC, or West Coast Power. One-year term reliability must-run, or RMR, agreements with the California Independent System Operator for all of the West Coast Power capacity have been negotiated and filed and are effective January 1, 2005. In January 2005, the West Coast Power El Segundo generating facility entered into a tolling agreement for its entire gross generating capacity of 670 MW commencing May 1, 2005 and extending through December 31, 2005. During the term of this agreement, the purchaser will be entitled to primary energy dispatch rights for the facility's generating capacity. The agreement is subject to the amendment of the El Segundo RMR agreement to switch to RMR Condition I and to otherwise allow the purchaser to exercise its primary dispatch rights under this agreement while preserving Cal ISO's ability to call on the El Segundo facility as a reliability resource under the RMR agreement, if necessary. Approximately 265 MW of capacity at the Long Beach generating facility was retired January 1, 2005.

We own approximately 1,591 MW of net generating capacity in other regions of the U.S. We also own interests in plants having a net generation capacity of approximately 2,063 MW in various international markets, including Australia, Germany and Brazil. We operate substantially all of our generating assets, including the West Coast Power plants.

We were incorporated as a Delaware corporation on May 29, 1992. Our common stock is listed on the New York Stock Exchange under the symbol "NRG". Our headquarters and principal executive offices are located at 211 Carnegie Center, Princeton, New Jersey 08540. Our telephone number is (609) 524-4500. The address of our website is www.nrgenergy.com. Our recent annual reports, quarterly reports, current reports and other periodic filings are available free of charge through our website.

From May 14 to December 23, 2003, we and a number of our subsidiaries undertook a comprehensive reorganization and restructuring under chapter 11 of the United States Bankruptcy Code. All NRG entities have emerged from chapter 11.

Environmental Developments

We are subject to a broad range of foreign, federal, state and local environmental and safety laws and regulations in the development, ownership, construction and operation of our domestic and international projects. These laws and regulations generally require that we obtain governmental permits and approvals before construction or during operation of our power plants. Environmental laws have become increasingly stringent over time, particularly the regulation of air emissions from power generators. Such laws generally require regular capital expenditures for power plant upgrades, modifications and the installation of certain pollution control equipment. It is not possible at this time to determine when or to what extent additional facilities or modifications to existing or planned facilities will be required due to potential changes to environmental and safety laws and regulations, regulatory interpretations or enforcement policies. In general, future laws and regulations are expected to require the addition of emissions control equipment or the imposition of certain restrictions on our operations. We expect that future liability under, or compliance with, environmental requirements could have a material effect on our operations or competitive position.

On March 15, 2005, the US Environmental Protection Authority, or USEPA, issued the Clean Air Mercury Rule, or CAMR, to permanently cap and reduce mercury emissions from coal-fired power plants, and this rule was published in the Federal Register on May 18, 2005. CAMR imposes limits on mercury emissions from new and existing coal-fired plants and creates a market-based cap-and-trade program that will reduce nationwide utility emissions of mercury in two phases (2010 and 2018). Consistent with the significant debate on whether USEPA has authority to regulate mercury emissions through a cap-and-trade mechanism (as opposed to a command-and-control requirement to install "maximum achievable control technology", or MACT, on a unit basis), twelve states, together with certain environmental organizations, have sued the federal government over CAMR. The states (including California, Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New Mexico, New York, Pennsylvania, Vermont and Wisconsin) allege that the rule violates the Clean Air Act (CAA) because it fails to treat mercury as a hazardous air pollutant. On August 4, 2005, the D.C. Circuit denied the environmental petitioners' request for a stay of CAMR. In addition, on June 29, 2005, Senators Leahy and Collins, together with 28 other senators, introduced a resolution in Congress to undo the delisting rule as it relates to mercury. Each of our coal-fired electric power plants will be subject to mercury regulation. However, since the final rule has yet to be implemented by individual states, it is not possible to identify in detail how the final mercury rules will affect our operations located in those states. Nevertheless, we continue to actively review emerging mercury monitoring and mitigation technologies to identify the most cost-effective options for the Company in implementing the required mercury emission controls on the stipulated schedule.

The USEPA had also proposed MACT standards for nickel from oil-fired units that would essentially require the installation of electrostatic precipitators on certain oil-fired units. These proposed requirements were originally included in drafts of CAMR. However, reflecting further dialog with generation industry participants and additional scientific review, the nickel MACT provisions were omitted on the basis of the USEPA's reconsideration of the requirement for new controls on nickel emissions from oil-fired generators. In fact, the USEPA issued a delisting rule on March 29, 2005 effectively removing the requirements that MACT standards for nickel (i.e., specific control technologies to be installed at each affected plant) apply to oil-fired power plants. A number of environmental groups have lodged legal challenges to the USEPA's delisting rule and this matter is still pending before the courts. As the delisting challenge relates to both nickel from oil-fired power plants and mercury from coal-fired plants, it is not possible to predict the outcome of the pending legal action.

On March 10, 2005, the USEPA announced the Clean Air Interstate Rule, or CAIR. This rule applies to 28 eastern states and the District of Columbia and caps 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 will apply to certain of the Company's power plants in New York, Massachusetts, Connecticut, Delaware and Louisiana. States must achieve the required emission reductions through: (a) requiring power plants to participate in a USEPA-administered interstate cap-and-trade system; or (b) measures to be selected by individual states. While the Company's current business plans include initiatives to address emissions (for example, the conversion of Huntley and Dunkirk to burn low sulfur coal), until the final rule as issued by USEPA is actually implemented by specific state legislation, it is not possible to identify with greater specificity the effect of CAIR on the Company, although it is possible that investments in additional backend control technologies will be required and the Company continues to evaluate these issues.

In 2004, USEPA re-proposed the Regional Haze Rule, designed to improve air quality in national parks and wilderness areas. This rule requires regional haze controls (by targeting SO_2 and NOx emissions from sources including power plants) through the installation of Best Available Retrofit Technology, or BART, in certain cases. The Clean Visibility Rule (or so-called BART rule) was signed by the USEPA on June 15, 2005 and published in the Federal Register on July 6, 2005, containing BART requirements and guidelines and providing states with several options for determining whether sources located within their borders should be subject to BART. States must develop their implementation plans by December 2007. The BART rule will affect many of the Company's facilities, although consistent with USEPA analysis released as part of issuing the Clean Visibility Rule, states which adopt the CAIR cap-and-trade program for SO_2 and NOx are allowed to apply CAIR controls to also satisfy BART, since emissions reductions required under CAIR are actually more stringent than those mandated under BART. Most of the Company's facilities expected to be affected by BART are also subject to CAIR, so no material additional expenditures are anticipated for compliance with the Clean Visibility Rule, beyond those separately needed for CAIR compliance.

Federal legislation has been proposed that would impose annual caps on U.S. power plant emissions of NOx, SO_2, mercury, and, in some instances, CO_2. While the Clear Skies bill stalled in Senate Committee on March 9, 2005, the Bush Administration continues to support, and work with Congress to achieve, passage of Clear Skies in 2005. Clear Skies overlaps significantly with the USEPA CAIR and CAMR, and would likely modify or supersede those rules if enacted as federal legislation.

Twelve states and various environmental groups have filed suit against USEPA asking the Court to address whether USEPA has an existing obligation to regulate greenhouse gases, or GHGs, under the Clean Air Act (CAA). On July 15, 2005, the US Court of Appeals for the District of Columbia Circuit issued an opinion in *Commonwealth of Massachusetts v. EPA* supporting USEPA's refusal to regulate GHG's emitted from any sources, although avoiding the issue of whether USEPA has authority, or an obligation, to regulate GHG's under the CAA. Further, eight states and the City of New York filed suit in 2004 against American Electric Power Company, Southern Company, Tennessee Valley Authority, Xcel Energy, Inc. and Cinergy Corporation, alleged to be the nation's five largest emitters of GHGs and all of which are owners of electric generation. In the latter case, an injunction is sought against each defendant to force it to abate its contribution to the "global warming nuisance" by requiring it to cap its CO_2 emissions and then reduce them by a specified percentage each year for at least a decade. The outcome of GHG-related litigation and proposed legislation cannot be predicted. The Company's compliance costs with any mandated GHG reductions in the future could be material.

Nine northeastern states have created a regional initiative to establish a cap-and-trade GHG program for electric generators, referred to as the Regional Greenhouse Gas Initiative, or RGGI. The model RGGI rule is to be announced in fall 2005, with an estimate of two to three years for participating states to finalize implementing regulations. The current proposal is for a RGGI cap to be based on region-wide average CO_2 emissions for the period 2000 to 2003. That cap, referred to as "stabilization", will remain the same through 2015. Before 2015, the RGGI states will periodically review the cap, the reductions achieved in the region and the success of the program and decide if ratcheting down the cap is needed. If RGGI is implemented, our plants in New York, Delaware, Massachusetts, and Connecticut may be materially affected.

The Massachusetts carbon regulation 310 CMR 7.29 "Emissions Standards for Power Plants" requires coal-fired generation located within the state to comply with CO_2 emissions restrictions. A carbon emissions cap will apply from 2006, while a rate requirement will apply in 2008. This regulation impacts the Company's Somerset facility. This means that if CO_2 emissions at Somerset exceed the annual cap from 2006, then the excess must be offset with CO_2 credits. However, since there are currently no approved CO_2 credits for use in Massachusetts, the Massachusetts Department of Environmental Protection, or MADEP, has proposed that generators annually report overages and at the time that there is a an established CO_2 market operating in the state, the Company would be required to purchase or generate sufficient CO_2 credits to offset the balance. At this point, the state has indicated its view that 2010 is likely to be the earliest year when such a carbon credit market exists, tying it to RGGI. Given the regulatory uncertainty surrounding implementation of Massachusetts's carbon market and the corresponding costs of CO_2 credits when that market exist, Somerset could be materially affected.

The Company's facilities in Germany are likely to be impacted by evolving emissions limitations imposed as a result of the ratification of the Kyoto Protocol, which entered into effect in February 2005. CO_2 emissions trading started in Germany in March 2005. While allocations of allowances have now been made by the government, they are being challenged by most recipients. Irrespective of the final allocation amounts, the Company does not expect the CO_2 trading program to be a material constraint on its business in Germany.

The Ozone Transport Commission, or OTC, was established by Congress and governs ozone and the NOx budget program in certain eastern states, including Massachusetts, Connecticut, New York and Delaware. In January 2005, the OTC stepped up its efforts to develop a multi-pollutant regime (SO_2, NOx, mercury and CO_2) that is expected to be completed by mid-2006 (with individual state implementation to follow). On June 8, 2005 the OTC members unanimously resolved to implement "CAIR-Plus" emissions regulations, based on concerns that the USEPA's CAIR fails to achieve attainment of 8-hour ozone and fine particulate matter. As a result, the OTC proposes to implement a regional plan containing emissions reduction targets from power plants that exceed those under CAIR. The OTC targets and timelines are as follows: (a) through June 2006: write model rule, with participating states signing a Memorandum of Understanding; (b) by December 2006 states file their implementation plans or reduction regulations; (c) 2008 Phase I reductions of NOx (to 1.87 million tons) and SO_2 (to 3.0 million tons) apply; (d) 2012 Phase II reductions of NOx (to 1.28 million tons) and SO_2 (to 2.0 million tons) apply; and (e) 2015 90% mercury removal required. OTC's proposed CAIR-Plus involves emissions reductions which are both sooner and more aggressive than CAIR (e.g., aggregate NOx reductions would be 25% greater than CAIR, while SO_2 reductions would be 33% greater than CAIR). The Company continues to be engaged in the OTC stakeholder process. While it is not possible to predict the outcome of this regional legislative effort, to the extent that the OTC is successful in implementing emissions requirements that are more stringent than existing regimes (including the recently reached New York settlement), the Company could be materially impacted.

Pursuant to New York State Department of Environmental Conservation, or NYSDEC, rules (the Acid Deposition Reduction Program, ADRP) fossil-fuel-fired combustion units in New York must reduce SO_2 emissions to 25% below the levels allowed in the federal Acid Rain Program starting January 2005 (and 50% below the levels allowed by the federal Acid Rain Program starting in January 2008). In addition, under ADRP generators now also have to meet the ozone season NOx emissions limit year-round.

On January 11, 2005, the Company reached an agreement with the State of New York and the NYSDEC in connection with voluntary emissions reductions at the Huntley and Dunkirk facilities, as discussed in Note 13, *Commitments and Contingencies*, to the Condensed Consolidated Financial Statements. The Consent Decree was entered by the U.S. District Court for the Western District of New York on June 3, 2005. The Company does not anticipate that any material capital expenditures, beyond those already planned, will be required for our Huntley and Dunkirk plants to meet the current compliance standards under the Consent Decree through the end of the decade, although, this does not reflect any additional capital expenditures that may be required to satisfy other federal and state laws.

In the 1990s, the USEPA commenced an industry-wide investigation of coal-fired electric generators to determine compliance with environmental requirements under the CAA associated with repairs, maintenance, modifications and operational changes made to facilities over the years. As a result, USEPA and several states filed suits against a number of coal-fired power plants in mid-western and southern states alleging violations of the CAA New Source Review (NSR) requirements. One of the more prominent suits of this type, involving Ohio Edison, announced an agreement on March 18, 2005 which settles NSR issues with respect to all coal-fired plant located in Ohio and obligates First Energy to spend $1.1 billion to install pollution control equipment through 2010. In another similar suit, the USEPA appeal in the Duke Energy case was finally heard and on June 15, 2005 the US Court of Appeal held in favor of Duke's position as to what type of modification triggers NSR and Prevention of Significant Deterioration provisions (although on August 1, 2005 the Department of Justice and some environmental groups filed petitions for rehearing of this case). In addition, on June 3, 2005 the US District Court reached conclusions favorable to Alabama Power through the court's interpretation of NSR rules relating to "routine maintenance, repair and replacement", or RMRR, and the correct test for determining a significant net emissions increase. In the meantime, the USEPA's proposed NSR rule from October 2003 underwent further review and on May 31, 2005, USEPA confirmed that it was maintaining the material provisions of the October 2003 proposal, particularly as they relate to a 20% per year capital spending limit for RMRR. Litigation challenging USEPA's NSR rule revisions has been on hold pending the outcome of USEPA's reconsideration. Plaintiffs have until the end of August to make further filings, with court hearings not expected on the NSR amended rule lawsuit until mid-2006.

On January 27, 2004, Louisiana Generating, LLC and Big Cajun II received a request for information under Section 114 of the CAA from USEPA seeking information primarily related to physical changes made at Big Cajun II and subsequently received a Notice of Violation based on alleged NSR violations. The current status of this matter is described in Note 13, *Commitments and Contingencies*, to the Condensed Consolidated Financial Statements.

Regulatory Developments

As participants in the wholesale electric energy market, the NRG companies are subject to regulatory oversight by the Federal Energy Regulatory Commission, or FERC. This regulatory oversight includes permitting the NRG companies to sell electricity and related products and services at market-based rates, and the authority to revise market rules to insure that the rates charged are just and reasonable. The

United States Congress has passed significant federal energy legislation, which is awaiting execution by the President. We are currently evaluating this legislation for its potential impact.

Northeast Region

New England

ISO-NE and NEPOOL operate a centralized energy market with "Day-Ahead" and "Real-time" energy markets. On August 23, 2004, ISO-NE filed its proposal for locational installed capacity, or LICAP, with FERC, which is deciding the issue in a litigated proceeding before an administrative law judge. Under the proposal, separate capacity markets would be created for distinct areas of New England, including southwest Connecticut and the rest of the state of Connecticut. While we view this proposal as a positive development, as it is currently proposed it would not permit us to recover all of our fixed costs. In response, we have submitted testimony, which includes an alternative proposal. On June 15, 2005, the FERC administrative law judge issued her recommended decision, which recommended FERC approve ISO-NE's proposed LICAP design with few exceptions. On July 15, 2005, NRG and the parties to the case filed briefs on exceptions to the decision with FERC. FERC's stated goal is to issue a decision on the precise terms of the NEPOOL LICAP market in the fall of 2005, so that the LICAP market can be implemented on January 1, 2006.

New York

In April 2003, NYISO implemented a demand curve in its capacity market and scarcity pricing improvements in its energy market. The New York demand curve eliminated the previous market structure's tendency to price capacity at either its cap (deficiency rate) or near zero. FERC had previously approved the demand curve, but on December 19, 2003, the Electricity Consumers Resource Council (ELCON) appealed the FERC decision to the U.S. Court of Appeals for the District of Columbia Circuit. On December 3, 2004, NRG Energy and other suppliers filed a brief in opposition. On May 13, 2005, the court denied the appeal thereby ending the case.

On January 7, 2005, NYISO filed proposed LICAP demand curves for the following capacity years: 2005-06, 2006-07 and 2007-08. Under the NYISO proposal, the LICAP price for New York City generation would be $126 per KW-year for the capacity year 2006-07. On January 28, 2005, we filed a protest at FERC asserting the LICAP price for this period should be at least $140 per KW-year. On April 21, 2005 FERC accepted the proposed demand curves with certain revisions. The FERC's modifications should also increase the capacity prices in New York City but the existing In-City mitigation measures will prevent us from obtaining these higher prices.

Our New York City generation is presently subject to price mitigation in the installed capacity market. When the capacity market is tight, the price we receive is capped by the mitigation price. However when the New York City capacity market is not tight, such as during the winter season, the proposed demand curve price levels should increase our revenues from capacity sales.

South Central Region

On April 1, 2004 Entergy filed revisions to its Open Access Transmission Tariff, or OATT, proposing: (1) to contract with an independent entity, (an Independent Coordinator of Transmission, or ICT), to provide oversight over the operations of the Entergy transmission system; (2) a new process for assigning cost responsibilities for transmission upgrades; and (3) a new Weekly Procurement Process (WPP). The FERC convened a series of technical conferences to discuss issues raised by Entergy's proposal.

On January 3, 2005, Entergy submitted a petition for declaratory order requesting guidance on issues associated with its proposal to establish an ICT. Entergy requested the Commission's guidance on whether the functions to be performed by the ICT will cause it to become a public utility under the Federal Power Act or the Transmission Provider under Entergy's OATT and whether Entergy's transmission pricing proposal satisfies the Commission's transmission pricing policy.

On March 22, 2005, FERC granted Entergy's Petition for Declaratory Order. FERC stated that the order benefits customers because implementation of the ICT proposal on an experimental basis goes beyond the transmission service offered under Entergy's existing pro forma transmission tariff and will permit a transmission decision-making process that is independent of control by any market participant or class of participants. The Commission believes the ICT may be just and reasonable with certain modifications. The Commission is prepared to grant Entergy's proposed transmission pricing proposal on a two-year experimental basis, subject to certain enhancements and monitoring and reporting conditions. Before any approval of Entergy's transmission pricing proposal can be given, Entergy must make a section 205 filing in a new docket detailing the enhanced functions that the ICT will perform. On May 27, 2005, Entergy submitted its Section 205 filing identifying the proposed revision to its OATT. On June 30, 2005, FERC conducted a technical conference to discuss issues raised by Entergy's filing.

On August 5, 2005, NRG and a group of generators filed comments with FERC, stating that; (1) the ICT entity should be given more authority; (2) the weekly procurement process should be open to all participants; and (3) the price of congestion should be calculated on a real-time basis.

On December 17, 2004, FERC ordered that an investigation and evidentiary hearing be held to determine whether Entergy is providing access to its transmission system on a short-term basis and in a just and reasonable manner. On March 22, 2005, FERC suspended the hearing until Entergy indicates whether it will accept the FERC conditional approval of its ICT proposal. On April 21, 2005, NRG and other generators and municipalities filed a motion for rehearing, claiming that the suspension of the hearing was unjust and unreasonable. On May 22, 2005, FERC issued an order stating that the this proceeding will be addressed in a future order.

Western Region

The Cal ISO and the California Energy Commission, or CEC, project a southern California peak load shortage this summer against a 15% reserve margin of up to of nearly 2,000 MW assuming normal weather conditions. The warnings from the Cal ISO and CEC are being heeded by the various regulatory agencies and they are moving to design a market that will provide the incentives to invest in new generation. The California Public Utility Commission, or CPUC, now requires that load-serving entities meet a 15-17% reserve margin by June 2006. This has prompted RFOs from load-serving entities, with the stated goal of engaging in bilateral contract negotiations with the merchant generators to secure their long-term capacity needs. They must demonstrate that they have secured at least 90% of their capacity needs by June 2005. This order will present significant opportunities to enter into new bilateral agreements. The Red Bluff and Chowchilla facilities have received capacity contracts for the period April 1, 2006 through December 31, 2007. In September 2004, Governor Schwarzenegger vetoed AB2006, commonly referred to as the “re-regulation” initiative with a promise to the California people that he wants to create a competitive energy market in California that will attract the investment capital required to meet growing load obligations.

At the Cal ISO, a market re-design, known as “Market Redesign and Technology Update”, is currently underway and has made significant progress in the past year. In addition to that activity, the CPUC is engaged in another critical portion of the market design that involves long-term resource adequacy and we expect an order to be issued by the California Public Utility Commission by year end 2005, thus creating greater opportunities for merchant generators in California.

Australian Region

The Australian based generation assets of NRG operate within the National Electricity Market, or NEM, a physical wholesale market encompassing the interconnected states of southern and eastern Australia.

In 2003, the governments spanning the NEM embarked upon a series of reforms to address perceived deficiencies in the governance and institutional structure of the market. During the quarter, draft legislation was finalized to give effect to these reforms, including the creation of new regulatory bodies and streamlined market rule change processes. These reforms are not intended to alter the fundamental design or operation of the market, but are designed to improve the regulatory framework in which it operates, and are scheduled to take effect mid-year.

On March 14, 2005, a blackout occurred in the South Australian region of the NEM, initiated by a transmission fault which triggered a sequence of events, including the operation of the Overspeed Protection Controllers on both Northern Power Station Units at Flinders. The National Electricity Code Administrator, or NECA, the regulatory body responsible for the enforcement of market rules at the time of the event, is conducting an investigation into the event. We are also conducting an investigation.

RESULTS OF OPERATIONS

The following tables provide selected financial information by segment for the three months ended June 30, 2005 and 2004:

	For the three months ended June 30, 2005						
	Northeast	South Central	Western	Other North America (In thousands)	Australia	All Other	Total
Energy revenue	$ 236,701	$ 59,964	$ (27)	$ 9,262	$ 36,272	$ 18,778	$ 360,950
Capacity revenue	72,845	45,559	—	1,860	—	20,662	140,926
Alternative revenue	329	—	—	366	—	45,153	45,848
O & M fees	—	—	—	—	—	4,475	4,475
Other revenues	5,801	3,406	2	(1,827)	20,865	4,121	32,368
Operating revenues	315,676	108,929	(25)	9,661	57,137	93,189	584,567
Cost of energy	157,568	71,539	20	5,041	24,352	40,118	298,638
Other operating expenses *	99,905	27,092	1,585	4,474	24,998	32,942	190,996
Depreciation and amortization	18,582	15,085	197	2,010	6,118	5,757	47,749
Operating income/(loss)	39,613	(4,790)	(1,826)	(1,866)	1,669	13,705	46,505

	For the three months ended June 30, 2004						
	Northeast	South Central	Western	Other North America (In thousands)	Australia	All Other	Total
Energy revenue	$ 184,615	$ 53,401	$ 1,746	$ 7,827	$ 28,271	$ 57,122	$ 332,982
Capacity revenue	71,924	44,512	—	23,766	—	20,324	160,526
Alternative revenue	6	—	—	363	—	42,291	42,660
O & M fees	—	—	—	(90)	—	5,027	4,937
Other revenues	18,484	4,584	(817)	(2,279)	8,522	4,024	32,518
Operating revenues	275,029	102,497	929	29,587	36,793	128,788	573,623
Cost of energy	113,198	50,402	803	2,949	18,445	39,321	225,118
Other operating expenses *	89,150	18,143	1,146	10,695	22,414	32,338	173,886
Depreciation and amortization	17,382	14,572	203	6,930	6,886	7,195	53,168
Operating income/(loss)	55,268	17,772	(1,224)	9,013	(10,954)	46,916	116,791

The following tables provide selected financial information by segment for the six months ended June 30, 2005 and 2004:

	For the six months ended June 30, 2005						
	Northeast	South Central	Western	Other North America (In thousands)	Australia	All Other	Total
Energy revenue	$ 513,249	$ 128,847	$ 136	$ 14,222	$ 68,101	$ 38,570	$ 763,125
Capacity revenue	137,678	90,835	—	4,264	—	42,123	274,900
Alternative revenue	345	—	—	1,094	—	93,309	94,748
O & M fees	—	—	—	—	—	9,139	9,139
Other revenues	(3,136)	6,393	14	(4,772)	37,822	7,476	43,797
Operating revenues	648,136	226,075	150	14,808	105,923	190,617	1,185,709
Cost of energy	342,721	137,999	380	6,525	46,982	89,256	623,863
Other operating expenses *	194,867	51,007	2,661	12,141	47,136	60,775	368,587
Depreciation and amortization	37,191	30,227	395	4,003	12,712	11,645	96,173
Operating income/(loss)	73,345	6,839	(3,285)	(7,863)	(907)	24,823	92,952

	For the six months ended June 30, 2004						
	Northeast	South Central	Western	Other North America (In thousands)	Australia	All Other	Total
Energy revenue	$ 442,251	$ 99,788	$ 2,950	$ 13,116	$ 82,333	$ 75,451	$ 715,889
Capacity revenue	130,694	89,839	(3,709)	40,878	—	41,455	299,157
Alternative revenue	11	—	—	1,018	—	87,759	88,788
O & M fees	—	—	(2)	124	—	10,400	10,522
Other revenues	32,613	8,135	(1,632)	(4,714)	16,689	8,441	59,532
Operating revenues	605,569	197,762	(2,393)	50,422	99,022	223,506	1,173,888
Cost of energy	259,233	98,492	921	4,725	41,907	85,520	490,798
Other operating expenses *	168,216	33,991	2,738	19,869	39,488	62,049	326,351
Depreciation and amortization	35,911	31,534	405	14,540	12,011	13,773	108,174
Operating income/(loss)	141,858	31,414	(6,458)	11,138	5,615	52,972	236,539

* Other operating expenses include “Cost of majority-owned operations” and “General, administrative and development” expenses, excluding

Cost of energy

For the three months ended June 30, 2005 compared to the three months ended June 30, 2004

Consolidated Results

Net Income

For the three months ended June 30, 2005, net income was $23.9 million, or $0.22 per diluted weighted average share of common stock compared to $83.0 million or $0.83 per diluted weighted average share of common stock for the three months ended June 30, 2004. The quarter began with mild temperatures in April and May, where in the Northeast region temperatures ranged from -6ºF to +4.5ºF from the average, whereas in June, the Northeast region had significant heat, up to 9ºF above average[1]. With gas prices 14% higher this quarter[2] versus second quarter 2004 increasing our spark spreads and dark spreads. Our New York City assets benefited from the increased spark spreads with generation 90% higher than second quarter 2004 due to competitor outages and the June heat. We also benefited from an 8% increase in generation in our Australia operation over second quarter 2004, partially due to the addition of the Playford station. However, compressed oil margins from our oil-fired facilities and reduced generation of 0.54 million MWh from our total domestic operations this quarter versus 2004 partially offset these higher spark and dark spreads. Generation decreased over second quarter 2004 primarily due to unplanned outages at our Huntley and Louisiana Generating facilities and the extension of a planned outage at our Indian River facility. The total decrease in generation due to these outages was 0.44 million MWh.

Net income results were favorably impacted by $5.1 million of net unrealized gains associated with forward sales of electricity supporting our Northeast assets, as well as lower interest expense as a result of the December 2004 refinancing which lowered interest expense by $8.8 million, as well as decreased tax expense. Additionally, we recorded an $11.6 million gain associated with the sale of our Enfield investment. These favorable results were offset by higher operating expenses and a reduction of $29.6 million in equity earnings in comparison to the second quarter of 2004. The decline in equity earnings is attributable to the $10.3 million mark-to-market gain in 2004 from the Enfield investment which was sold on April 1, 2005, and reduced equity earnings of $17.5 million from WCP related to the CDWR contract, which expired on December 31, 2004. Our net income during the second quarter of 2004 was also positively impacted by a one time payment of $38.5 million from the Connecticut Light and Power settlement.

Revenues from Majority-Owned Operations

Revenues from majority-owned operations were $584.6 million for the three months ended June 30, 2005 compared to $573.6 million for the three months ended June 30, 2004. Revenues for the three months ended June 30, 2005 included $361.0 million of energy revenues compared to $333.0 million of energy revenues for the three months ended June 30, 2004. Of the $361.0 million, 83% were non-contracted and non-capacity generation revenues; or merchant revenues. In the second quarter of 2004, 66% of our energy revenues were merchant. The increase in energy revenues in 2005 versus 2004 was due to increased generation from our New York City assets which increased revenue by $27 million, and to a lesser extent, our NEPOOL and Oswego assets which increased revenue by $31.7 million, Competitor outages and the June heat drove the higher generation in New York City and NEPOOL assets. This favorable variance versus prior year was partially offset by the 2004 collection of $38.5 million from the Connecticut Light and Power settlement, recorded as energy revenues, which is reflected in our All Other region.

Capacity revenues for the three months ended June 30, 2005 were $140.9 million compared to $160.5 million for the three months ended June 30, 2004. Capacity revenues were unfavorable for the second quarter of 2005 compared to 2004 due to the loss of capacity revenues from the Kendall facility, which was sold in the fourth quarter of 2004. Alternative revenues and Operations and maintenance, or O&M, fees for the three months ended June 30, 2005 were $45.8 million and $4.5 million, respectively. This compares to $42.7 million of alternative energy revenues and $4.9 million of O&M fees in the second quarter of 2004. Higher capacity prices from our Thermal operations positively impacted the alternative revenues results by $2.6 million, due to an annual increase in contract rates. Other revenues include derivative and financial revenues, natural gas sales, Fresh Start-related contract amortization, and expense recovery revenues. For the three months ended June 30, 2005, other revenues totaled $32.4 million compared to $32.5 million for the three months ended June 30, 2004. Other revenues were positively impacted by higher gas sales of $3 million and less contract amortization in 2005 versus 2004 of $7.3 million, as contracts have rolled off over the course of 2004. These favorable items were offset by $11.5 million of lower expense recovery revenues. Expense recovery revenues relate to our Connecticut RMR agreements.

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1 Information available from the *National Climatic Data Center* of the *National Oceanic & Atmospheric Administration*, or *NOAA*

2 Per the Henry Hub gas price index published by *Platts Gas Daily*

Cost of Majority-Owned Operations

Cost of majority-owned operations for the three months ended June 30, 2005 was $436.5 million or 75% of revenues from majority-owned operations. Cost of majority-owned operations for the three months ended June 30, 2004 was $353.3 million or 62% of revenues from majority-owned operations. Cost of majority-owned operations consists of the cost of energy (primarily fuel costs), operating labor, operating and maintenance costs and non-income based taxes. Cost of energy for the second quarter of 2005 was $298.6 versus $225.1 million for the second quarter of 2004. Higher gas and oil fuel cost in our domestic operations were the primary drivers of the increased fuel costs, with gas prices 14% higher and oil prices 37.4% higher than second quarter last year. Our gas fuel cost increased by $30.3 million, 89% of which was due to higher generation from our New York City assets. Oil fuel cost increased by $28.6 million, 52% of which was due to higher generation from our oil-fired assets and 48% was due to an increase in price. Additionally, purchased energy increased by $17.5 million, as our South Central operation purchased energy to meet its contract load during its unplanned outages.

O&M costs for the second quarter 2005 totaled $132.6 million versus $121.4 million in the second quarter of 2004. This increase is driven by a $10.5 million increase in major maintenance projects related to the low-sulfur coal conversions and turbine overhauls in our Western New York plants and Indian River plant, which were underway during the second quarter of 2005.

Depreciation and Amortization

Our depreciation and amortization expense for the three months ended June 30, 2005 and 2004 was $47.7 million and $53.2 million, respectively. The decrease in depreciation and amortization from 2005 to 2004 is primarily due to the 2004 sale of our Kendall plant, which contributed $4.9 million in depreciation and amortization expense in the second quarter of 2004.

General, Administrative and Development

Our general, administrative and development, or G&A, costs for the three months ended June 30, 2005 were $53.2 million compared to $45.7 million for the three months ended June 30, 2004. These amounts include corporate costs of $26.9 million, or 4.6% of operating revenues, for the second quarter of 2005, as compared to $23.3 million, or 4.1% of operating revenues, for the second quarter of 2004. G&A costs are primarily comprised of corporate and regional office labor, corporate and plant insurance and external professional support, such as legal, accounting and audit fees. G&A costs have been adversely impacted by $5.5 million of increased insurance expenses as compared to the second quarter 2004.

Corporate Relocation Charges

During the three months ended June 30, 2005, charges related to our corporate relocation activities were $0.5 million as compared to $5.6 million for the same period in 2004. This decrease in expense reflects the fact that the relocation of our corporate headquarters is nearly complete. The relocation plan will be completed by the end of 2005, and we expect to incur an additional $1 million.

Impairment charges

During the three months ended June 30, 2005 we recorded $0.2 million of impairment charges as compared to $1.7 million in the second quarter of 2004. On an annual basis we evaluate the possible impairment of our assets, unless certain events occur which trigger an impairment analysis.

Equity in Earnings of Unconsolidated Affiliates

During the three months ended June 30, 2005, we recorded $16.5 million of equity earnings from our investments in unconsolidated affiliates as compared to $46.1 million for the three months ended June 30, 2004. Our equity earnings from WCP comprised $4.4 million for the second quarter of 2005 as compared to $21.9 million for the second quarter of 2004, a net decrease of $17.5 million. This decrease in earnings is because the CDWR contract expired in December 2004. Additionally, equity earnings in 2004 included a $10.3 million mark-to-market unrealized gain at Enfield associated with changes in the fair value of energy-related derivative instruments not accounted for as hedges in accordance with SFAS No. 133. We sold our Enfield investment on April 1, 2005.

Other equity investments included in the 2005 results are MIBRAG and Gladstone, comprising $0.5 million and $5.6 million, respectively. During the three months ended June 30, 2004, we recorded earnings of $4.5 million for MIBRAG and $3.5 million for

Gladstone. MIBRAG's equity earnings for 2005 were negatively impacted by planned outages by two of its primary customers, reducing the amount of coal they purchased from MIBRAG by €8 million (approximately $10.3 million). Our equity earnings were negatively impacted by 50% of this amount.

Write Downs and Gains/(Losses) on Sales of Equity Method Investments

During the second quarter of 2005, we sold our 25% interest in Enfield. The sale resulted in net pre-tax proceeds of $64.6 million and a pre-tax gain of $11.6 million, including the post-closing working capital adjustments. For the three months ended June 30, 2004, we collected $1.2 million of post-sale payments for Loy Yang and Calpine Cogeneration, which were recorded as a gain.

Other income, net

During the three months ended June 30, 2005 and 2004, we recorded $7.7 million and $8.1 million, respectively, of other income, net. Other income includes interest income, gain or loss on foreign exchange, and other miscellaneous items. Interest income for the second quarter of 2005 increased over the second quarter of 2004 by $4.1 million, from $5.5 million to $9.6 million, due to more efficient management of unrestricted cash and maximizing interest income. This increase was partially offset in the second quarter of 2004 from recognizing an insurance gain from a previous loss incurred, in the amount of $2.5 million.

Interest expense

Interest expense for the three months ended June 30, 2005 was $50.6 million as compared to $66.2 million, for the three months ended June 30, 2004. Interest expense declined, in part, due to the sale of Kendall in the fourth quarter of 2004. Kendall incurred $6.5 million of interest expense in the second quarter of 2004. Additionally, in December 2004 we refinanced our Senior Credit Facility and lowered our interest rate by 212.5 basis points. During the first quarter of 2005 we redeemed and repurchased $415.8 million of our Second Priority Notes. Together, these transactions reduced interest expense by approximately $11.8 million. In connection with our refinancing of our debt in Australia, we paid down $57.2 million during the first six months of 2005. As such, interest expense paid by our Australian operation decreased by $2.9 million quarter over quarter.

Income Tax Expense

Income tax expense was $8.1 million and $36.3 million for the three months ended June 30, 2005 and 2004, respectively. The effective tax rate was 25.9% and 34.4% for the three months ended June 30, 2005 and 2004, respectively. The effective income tax rate for the three months ended June 30, 2005 differs from the U.S. statutory rate of 35% due to lower tax rates for income derived in foreign jurisdictions. This was partially offset by the Subpart F taxation for the sale of Enfield, which increased our domestic tax expense by $11.4 million in the second quarter of 2005.

The effective tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and the creation of valuation allowances in accordance with SFAS No. 109. These factors and others, including our 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 Taxes

We classified as discontinued operations the operations and gains/losses recognized on the sale of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. During the three months ended June 30, 2005 and 2004, we recorded income from discontinued operations of $0.7 million and $13.6 million, respectively. Discontinued operations for the three months ended June 30, 2005 consist of various expenses related to NRG McClain to effect its liquidation. During the period ended June 30, 2004, discontinued operations consisted of the results of our NRG McClain LLC, Penobscot Energy Recovery Company, or PERC, Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee, Hsin Yu, LSP Energy (Batesville) and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha and NEO Tajiguas LLC). All discontinued operations were sold prior to December 31, 2004.

Regional Discussion

Northeast Region Results

Operating Income

For the three months ended June 30, 2005, operating income for the Northeast region was $39.6 million, as compared to $55.3 million for the three months ended June 30, 2004. The quarter began with mild temperatures in April and May, where temperatures ranged from -6ºF to +4.5ºF from the average, whereas in June, the Northeast region had significant heat, up to 9ºF above average[1]. With gas prices 14%[2] higher this quarter versus second quarter 2004 increasing our spark spreads and dark spreads. However, oil margins were compressed by 55% at our oil-fired generation and an overall 2.7% lower generation from the Northeast assets this quarter versus 2004 partially offset these increased spark and dark spreads. Generation decreased this quarter versus last quarter primarily due to planned and unplanned outages at our Huntley facility and the extension of a planned outage at our Indian River facility. The unplanned outages reduced generation by 0.12 million MWh. Higher major maintenance costs of $8.6 million were due to these more extensive outages, which were partially offset by lower property tax expense of $3.2 million, as compared to the same quarter last year. Also, during the second quarter of 2005, we recorded $5.1 million of net unrealized gains associated with forward sales of electricity supporting our Northeast assets.

Revenues

Revenues from our Northeast region totaled $315.7 million for the three months ended June 30, 2005 compared to $275.0 million for the three months ended June 30, 2004. Revenues for the three months ended June 30, 2005 included $236.7 million in energy revenues compared to $184.6 million for the three months ended June 30, 2004. This favorable increase versus 2004 is due to the increased generation from our New York City facilities of 0.23 million MWh and NEPOOL assets of 0.16 million MWh, or 48.3% more than in the second quarter of 2004. Outages of local competitors in the early part of the quarter and excessive heat in June provided the opportunity for the New York City and NEPOOL assets to sell more merchant energy. Capacity revenues for the three months ended June 30, 2005 were stable at $72.8 million compared to $71.9 million for the three months ended June 30, 2005 and 2004, respectively. Other revenues include derivative and financial revenues, natural gas sales, Fresh Start-related contract amortization, and expense recovery revenues. For the three months ended June 30, 2005, other revenues totaled a $5.8 million compared to $18.5 million of other revenues for the three months ended June 30, 2004. Other revenues were lower in 2005 by $11.5 million from our Connecticut RMR agreements. As of the first quarter of 2005, we recorded the maximum reimbursement under those agreements.

Operating Expenses

Operating expenses, consisting of cost of energy, other operating expense, and depreciation and amortization, for our Northeast operations for the three months ended June 30, 2005 were $276.1 million or 87% of the Northeast's revenues, as compared to $219.7 million or 80% of revenues for the three months ended June 30, 2004. The increase in operating expenses is primarily driven by the increase in the cost of energy, as generation and fuel prices increased from the second quarter 2005 compared to the second quarter 2004.

Cost of energy in the Northeast was $157.6 million as compared to $113.2 million in 2004, a growth of $44.4 million. Oil costs in our Northeast region increased by $29.2 million, with $16.6 million of the increase due to increased generation from our NEPOOL assets. Gas costs increased by $26.6 million over the second quarter of 2004. Of this total, $27.7 million was due to increased generation at our New York City assets. Coal costs at our Northeast region decreased by $2.7 million, as lower generation from our Northeast coal-fired plants more than offset higher coal prices. Because of planned and unplanned outages at our Northeast coal-fired plants, generation from these assets decreased by 23%, which lowered expense by $14.1 million compared to second quarter 2004. However, higher prices offset the impact of lower generation and accounted for an $11.4 million increase in coal costs versus second quarter 2004. The increase in coal prices impacted our Indian River facility in particular. Indian River burns eastern coal which has experienced high price volatility versus western coal. As such, this plant was more adversely affected by the overall increase in coal prices this quarter versus second quarter 2004.

Other operating expenses includes O&M expenses, non-income based taxes, and G&A costs. O&M for our Northeast region was $76.7 million for the second quarter 2005 as compared to $68.2 million in the second quarter 2004. O&M costs include operating labor, normal and major maintenance and plant utilities. The $8.5 million increase in O&M expense this quarter versus second quarter 2004 is due to increased major maintenance projects including the low-sulfur conversion projects and the turbine overhauls at our Western New York plants and Indian River. Other non-income based taxes and G&A expenses for the Northeast region include sales and property taxes, administrative regional office costs, insurance and corporate allocations. For the second quarter 2005, non-income

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1 Information available from the National Climatic Data Center of the National Oceanic & Atmospheric Administration, or NOAA

2 Per the Henry Hub gas price index published by *Platts Gas Daily*

based taxes and G&A expenses totaled $23.5 million for the second quarter of 2005 as compared to $20.7 million in 2004. This increase is due to the increase in the corporate allocations per our new allocation methodology as discussed in Note 10, *Segment Reporting,* to the Condensed Consolidated Financial Statements. Additionally, the Northeast's regional office costs were largely recorded as corporate costs in 2004. This increase was offset by lower property taxes of $3 million.

South Central Region Results

Operating Income

For the period ending June 30, 2005, the South Central region incurred an operating loss of $4.8 million, as compared to $17.8 million in operating income for the period ended June 30, 2004, a decrease of $22.6 million. This quarter, our Big Cajun II facility experienced several forced outages, which required the purchase of additional higher priced energy to meet its contract load-following obligation. Due to both forced and unforced outages, total generation from the South Central assets decreased by 17.5% over second quarter last year. Big Cajun II also had a planned outage in the second quarter and as such, South Central's major maintenance expense increased this quarter compared to the second quarter 2004.

Revenues

Revenues from our South Central region were $108.9 million for the three months ended June 30, 2005 compared to $102.5 million for the three months ended June 30, 2004. Revenues for the three months ended June 30, 2005 included $60.0 million in energy revenues, of which 78% were contracted. This compares to $53.4 million of energy revenues for the three months ended June 30, 2004; 70.7% of which were contracted. Higher contracted energy sales drove the overall increase in energy revenues, as new and higher contract rates became effective on January 1, 2005. Capacity revenues were $45.6 million and $44.5 million in the three months ended June 30, 2005 and 2004, respectively. Capacity revenues are stable quarter versus quarter as they are fully contracted. Other revenues include coal sales, derivative and financial revenues and Fresh Start-related contract amortization. For the three months ended June 30, 2005, other revenues totaled $3.4 million compared to $4.6 million for the three months ended June 30, 2004 due to lower Fresh Start amortization and lower coal sales.

Operating Expenses

Operating expenses for our South Central region for the three months ended June 30, 2005 were $113.7 million or 104% of South Central's revenues, as compared to $83.1 million or 81% of revenues for the three months ended June 30, 2004. The increase of operating expenses is primarily driven by the increase in cost of energy. Total cost of energy in South Central was $71.5 million as compared to $50.4 million in 2004, an increase of $21.1 million. A number of forced and unforced outages combined with higher contract demand due to hot weather in June required the purchase of energy to meet contract load obligations at prices higher than our coal-based generating assets. Second quarter purchased energy costs were up $23.7 million compared to last year. An average price increase of $11.21 per megawatt hour of purchased energy also contributed to the higher cost versus second quarter 2004. This increase was offset by $3.7 million lower coal cost due to 17.5% lower generation.

Other operating expenses were $27.1 million and $18.1 million for June 30, 2005 and 2004, respectively. O&M for our South Central region was $15.7 million for the second quarter 2005 as compared to $10.7 million in the second quarter 2004. Of this increase, $5.6 million is related to higher major maintenance due to both planned and unplanned outages. Non-income based taxes and G&A expenses for South Central for the three months ended June 30, 2005 were $11.4 million as compared to $7.4 million for the three months ended June 30, 2004. The increase is due to the new NRG allocations methodology as discussed in Note 10, *Segment Reporting,* to the Condensed Consolidated Financial Statements. Additionally, much of the South Central regional office had been recorded as corporate costs in the second quarter of 2004.

Western Region Results

For the period ending June 30, 2005, the Western region incurred an operating loss of $1.8 million, as compared to a $1.2 million loss for the period ended June 30, 2004. The negative variance in operating costs is due to the expiration of the Red Bluff RMR agreement in December 2004.

Other North America Region Results

For the three months ended June 30, 2005, the Other North America region realized an operating loss of $1.9 million on revenues of $9.7 million, as compared to operating income of $9.0 million and revenues of $29.6 million for the three months ended June 30, 2004. This decrease of $10.9 million in operating income is due to the sale of Kendall in late 2004. Kendall had operating income of $7.3 million and revenues of $20.1 million in the second quarter of 2004. Operating expenses and depreciation and amortization for our Other North America region for the three months ended June 30, 2005 were $9.5 million and $2 million respectively. For the second quarter of 2004, operating expenses and depreciation and amortization were $13.6 million and $6.9 million, respectively. The favorable variance in both of these is related to the sale of Kendall.

Australia Region Results

Operating Income

For the period ending June 30, 2005, the Australia region's operating income was $1.7 million, as compared to a $11.0 million operating loss for the period ended June 30, 2004. Higher generation of 0.98 million MWh and 3% higher pool prices this quarter versus second quarter 2004 were the drivers for the increase in operating income.

Revenues

Revenues from our Australia region totaled $57.1 million for the three months ended June 30, 2005 compared to $36.8 million for the three months ended June 30, 2004, an increase of $20.3 million. Revenues for the three months ended June 30, 2005 included $36.3 million in energy revenues compared to $28.3 million of energy revenues for the three months ended June 30, 2004. These favorable results during 2005 were largely driven by higher generation, which increased from 1.3 million MWh to 1.4 million MWh, or 8% higher versus second quarter 2004. The increase in generation was due to the full commercialization of our Playford station in late 2004. Further, a planned outage in the second quarter of 2004 contributed to the difference. Other revenues include derivative and financial revenues, natural gas sales, and Fresh Start-related contract amortization. Other revenues increased this quarter over second quarter 2004 from $8.5 million to $20.9 million. The increase is due to less contract amortization in 2005 versus 2004 of $4.3 million, derivative revenues of $4.6 million, and $2.2 million of financial revenues.

Operating Expenses

Operating expenses for our Australia region for the three months ended June 30, 2005 were $55.5 million or 97% of revenues, as compared to $47.7 million or 130% of revenues for the three months ended June 30, 2004. Cost of energy for our Australia region for the three months ended June 30, 2005 was $24.4 million as compared to $18.4 million for the three months ended June 30, 2004. The $6 million increase in cost of energy is related to increased costs associated with our Playford facility, which was not fully operational in the second quarter of 2004. Higher cost of gas for the Osborne power plant and higher cost of purchased energy totaling $3.6 million, also unfavorably impacted the cost of energy. Other operating expenses for Australia for the three months ended June 30, 2005 and 2004 were $25 million and $22.4 million, respectively. The increase is due to the new NRG allocations methodology as discussed in Note 10 to the Condensed Consolidated Financial Statements. These results do not include the equity earnings of our Gladstone investment.

For the six months ended June 30, 2005 compared to the six months ended June 30, 2004

Consolidated Results

Net Income

For the six months ended June 30, 2005, net income was $46.5 million, or $0.43 per diluted weighted average share of common stock compared to net income of $113.3 million or $1.13 per diluted weighted average share of common stock for the six months ended June 30, 2004. The year began with mild temperatures for the winter months and spring, where in the Northeast region temperatures ranged from -7.5ºF to +4.5ºF from the average, whereas in June, the Northeast region had significant heat, up to 9ºF above average[1]. With gas prices 13.6% higher[2] than the first six months of 2004, spark spreads, and to a lesser extent coal dark spreads, were strong, while oil spreads were compressed relative to the first six months of 2004. Our New York City assets benefited

1 Information available from the National Climatic Data Center of the National Oceanic & Atmospheric Administration, or NOAA

2 Per the Henry Hub gas price index published by *Platts Gas Daily*

from the increased spark spreads as generation was 100% higher versus last year. We also recorded $33.1 million of net unrealized losses associated with forward sales of electricity supporting our Northeast assets. Additionally, our South Central region experienced a number of planned and unplanned outages over the first six months of 2005 which resulted in 5% lower generation and a $23.6 million decrease in operating income. In our Australia region, increased generation from the Playford station only partially offset the impact of weak pool prices due to a mild summer season during the first quarter.

Net income results were favorably impacted by the $11.6 million pre-tax gain on the sale of our Enfield investment, lower interest expense, and higher other income. In December 2004, we refinanced our Senior Credit Facility, decreasing our interest expense by 212.5 basis points as compared to the facility in place during the first six month of the 2004. Additionally, during the first quarter of 2005, we re-purchased $415.8 million of our Second Priority Notes, further contributing to the reduced interest expense versus the period ended June 30, 2004. Other income for the period ended June 30, 2005 was favorable versus the period ended June 30, 2004 by $21.4 million, primarily due to a $13.5 million gain from a settlement relating to the TermoRio project in Brazil, a $3.5 million contingent gain related to a previously sold project, the Crockett Cogeneration Facility, and $6.8 million in higher interest income due to higher average outstanding cash balances and more efficient cash management. These favorable variances were offset by higher operating expenses and decreased equity earnings for the six months ended June 30, 2005 as compared to the same period in 2004. Additionally, during the first half of 2005 operating expenses increased due to more extensive planned outages as compared to the same period in 2004. Equity earnings were negatively impacted by the results of WCP, whose CDWR contract expired in December 2004.

Revenues from Majority-Owned Operations

Revenues from majority-owned operations were $1,185.7 million for the six months ended June 30, 2005 compared to $1,173.9 million for the six months ended June 30, 2004. Revenues for the six months ended June 30, 2005 included $763.1 million of energy revenues compared to $715.9 million of energy revenues for the six months ended June 30, 2004. Of the $763.1 million, 85% are merchant revenues; in the second quarter of 2004, 70% of our energy revenues were merchant. The increase in energy revenues versus 2004 were largely driven by the increased merchant generation from our New York City assets, which doubled for the period June 30, 2005 as compared to the six months ended June 30, 2004, and to a lesser extent, to our NEPOOL assets, where generation increased by 37.7%. The increased generation from these assets can be attributed to outages of local competitors during the early part of the year and to the significant heat in June. South Central also recognized higher energy revenues for the first six months of 2005 as compared to the period ended June 30, 2004. Energy sales at South Central were favorable due to the higher energy prices driven by gas prices, favorable weather in the first quarter, increased contract rates, and local nuclear plant outages in the first quarter. Increased generation and energy revenues from those operations were offset by declines in energy revenues from our Western New York facilities because of planned and unplanned outages. Additionally, a one time payment of $38.5 million from the Connecticut Light and Power settlement contributed to energy revenue during the second quarter of 2004.

Capacity revenues for the six months ended June 30, 2005 were $274.9 million compared to $299.2 million for the six months ended June 30, 2004. Capacity revenues were unfavorable versus last year due to the loss of capacity revenues from the Kendall facility, which was sold in the fourth quarter of 2004, and the addition of new generation and increased imports in New York, which depressed capacity prices for our assets in the Western New York market during the first half of 2005. This loss was partially offset by $23.9 million additional capacity revenues during the period related to our Connecticut RMR settlement agreement, which was approved by FERC on January 22, 2005. Alternative revenues and O&M fees for the six months ended June 30, 2005 were $94.7 million and $9.1 million, respectively. This compares to $88.8 million of alternative energy revenues and $10.5 million of O&M fees for the six months ended June 30, 2004. Other revenues include derivative and financial revenues, natural gas sales, Fresh Start-related contract amortization, and expense recovery revenues. For the six months ended June 30, 2005, other revenues totaled $43.8 million compared to $59.5 million of other revenues for the six months ended June 30, 2004. Other revenues were positively impacted by $16.8 million in lower contract amortization in 2005 versus 2004 as contracts rolled off, $5.8 million in higher gas sales, and gains from financial hedges relative to the second quarter of 2004. This is offset by the net $33.1 million in mark-to-market losses through June 30, 2005 and $14.5 million in lower expense recovery revenues associated with our Connecticut RMR agreements.

Cost of Majority-Owned Operations

Cost of majority-owned operations for the six months ended June 30, 2005 was $889.4 million or 75% of revenues. Cost of majority-owned operations for the six months ended June 30, 2004 was $735.0 million or 62.7% of revenues from majority-owned operations. Cost of energy for the period ended June 30, 2005 was $623.9 versus $490.8 million for the same period in 2004. Cost of energy for our Northeast region increased by $83.5 million, driven primarily by increased gas and oil costs, both of which were driven by increased generation from our New York City assets and, to a lesser extent, our NEPOOL assets. Our South Central region's cost of energy increased by $39.5 million, 80% of which was due to higher purchased energy costs. Because of a number outages over the first half of the year, South Central was forced to purchase energy to fill its load obligation under its long-term contracts.

O&M costs for the first six months of 2005 totaled $244.1 million versus $218.8 million in the comparable period of 2004. This increase is driven by the increase in major maintenance projects and more extensive outages in 2005, as compared to 2004. The low-sulfur coal conversions and turbine overhauls of the Western New York plants and Indian River plant is a main focus for many of the major maintenance and outages in 2005. South Central also went through a significant outage to install a low-NO_X burner on one of its units.

Depreciation and Amortization

Our depreciation and amortization expense for the six months ended June 30, 2005 and 2004 was $96.2 million and $108.2 million, respectively. The decrease in depreciation and amortization from 2005 to 2004 is primarily due to the 2004 sale of our Kendall plant, which contributed $10.4 million in depreciation and amortization expense in the first six months of 2004.

General, Administrative and Development

Our general, administrative and development costs, or G&A, for the six months ended June 30, 2005 were $103.1 million compared to $82.1 million for the six months ended June 30, 2004. Corporate costs represent $51.2 million or 4.3% of revenues and $39.6 million or 3.4% of revenues for the periods ended June 30, 2005 and 2004, respectively. G&A costs have been adversely impacted by $8.7 million of increased insurance expense, $2.2 million of bad debt expense associated with a third party, and increased consulting costs related to Sarbanes Oxley compliance for our 2004 year-end audit.

Corporate Relocation Charges

During the six months ended June 30, 2005, charges related to our corporate relocation activities were $3.9 million as compared to $6.8 million for the same period in 2004. Included in this year's charges is $2.8 million related to the lease abandonment charges associated with our former Minneapolis office with the remainder primarily related to the relocation, recruitment and transition costs. Second quarter 2004 charges include employee severance and termination benefits and relocation, recruitment and transition costs.

Corporate Reorganization Charges

For the six months ended June 30, 2004, we incurred $3.6 million in corporate reorganization charges associated with our emergence from bankruptcy.

Equity in Earnings of Unconsolidated Affiliates

During the six months ended June 30, 2005, equity earnings from our investments in unconsolidated affiliates was $53.4 million compared to $63.8 million for the six months ended June 30, 2004. Our earnings in WCP accounted to $8.5 million and $27.9 million for the six months ended June 30, 2005 and 2004, respectively. The decrease in WCP's equity earnings is due to the expiration of the CDWR contract in December 2004. WCP's decrease is partially offset by the favorable impact of Enfield's and Gladstone's year-over-year results. Equity earnings for our Enfield investment, which was sold on April 1, 2005, were $16 million for the six months ended June 30, 2005 versus $12.1 million in the comparable period in of 2004. For the six months ended June 30, 2005 results for Enfield include approximately $12 million of unrealized gain associated with mark-to-market increase in the fair value of energy-related derivative instruments, as compared to $9.1 million of unrealized gain for the same period of 2004. Gladstone's equity earnings were $11.7 million for the six months ended June 30, 2005 as compared to $6.7 million for the same period in June 2004.

Other equity investments included in the 2005 results include MIBRAG which comprised $7.9 million and $10.9 million for the periods ended June 30, 2005 and 2004, respectively. MIBRAG's equity earnings for 2005 were negatively impacted by second quarter planned outages by two of its primary customers, reducing the amount of coal purchased from MIBRAG by €8 million (approximately $10.3 million). Our equity earnings were negatively impacted by our 50% share of this amount.

Write Downs and Gains/(Losses) on Sales of Equity Method Investments

During the six months ended June 30, 2005, we sold our 25% interest in Enfield. The sale resulted in net pre-tax proceeds of $64.6 million and pre-tax gain of $11.6 million, including the post-closing working capital adjustments. During the six months ended June 30, 2004, we sold our Loy Yang investment which resulted in a $1.3 million loss, offset by a $0.7 million gain associated with the sale of Calpine Cogeneration.

Other income, net

Other income had a net increase of $21.4 million during the six months ended June 30, 2005 as compared to the same period in 2004. Other income in 2005 was favorably impacted by a $13.5 million gain from the settlement related to our TermoRio project in Brazil and a contingent gain of $3.5 million related to the sale of a former project, the Crockett Cogeneration Facility, which was sold in 2002. Other income was also favorably impacted by $6.8 million of higher interest income related to more efficient management of higher average cash balances.

Refinancing expense

Refinancing expenses for the six months ended June 30, 2005 and 2004 were $25 million and $30.4 million, respectively. In the first half of 2005, we redeemed and purchased a total of $415.8 million of our Second Priority Notes. As a result of the redemption and purchases, we incurred $34.8 million in premiums and write-offs of deferred financing costs. Additionally, projects in our Australia region refinanced their project debt during the first six months of 2005 resulting in the write-off of $9.8 million of debt premium. During the six months ended June 30, 2004, we refinanced certain amounts of our term loans with additional corporate level high yield notes, which resulted in $15.1 million of prepayment penalties and a $15.3 million write-off of deferred financing costs.

Interest expense

Interest expense for the six months ended June 30, 2005 was $106.6 million as compared to $129.0 million for the six months ended June 30, 2004. Interest expense was favorably impacted by the sale of Kendall in the fourth quarter of 2004. Kendall incurred $13 million of interest expense in the six months ended June 30, 2004. Additionally, refinancing of our Senior Credit Facility lowered our interest rate by 212.5 basis points and the $415.8 million redemption and purchases of our Second Priority Notes during the first quarter of 2005 reduced interest expense on our corporate debt by approximately $20.8 million. Australia also refinanced and paid down $57.2 million of their project debt during the first six months of 2005, resulting in a $4.5 million lower interest expense for the six months ended June 30, 2005 as compared to the same period in 2004.

Income Tax Expense

Income tax expense was $12.9 million and $50.6 million for the six months ended June 30, 2005 and 2004, respectively. The overall effective tax rate was 21.9% and 33.4% for the six months ended June 30, 2005 and 2004, respectively. The effective income tax rate for the six months ended June 30, 2005 and 2004 differs from the U.S. statutory rate of 35% due to the earnings in foreign jurisdictions taxed at rates lower than the U.S. statutory rate, rendering an effective tax rate of 11.1% and 19.7%, respectively, on foreign income. Our 2005 domestic income tax expense partially offset the low foreign effective tax rate due to the Subpart F inclusion and taxation for our gain on the sale of Enfield, totaling $11.4 million.

The effective tax rate may vary from period to period depending on, among other factors, the geographic and business mix of earnings and losses and the creation of valuation allowances in accordance with SFAS No. 109. These factors and others, including our 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 Taxes

We classified as discontinued operations the operations and gains/losses recognized on the sale of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. During the six months ended June 30, 2005 and 2004, we recorded a gain from discontinued operations of $0.7 million and $12.4 million, respectively. Discontinued operations for the six months ended June 30, 2005 consist of various expenses related to NRG McClain to effect its liquidation. During the six months ended June 30, 2004, discontinued operations consisted of the results of our NRG McClain LLC, Penobscot Energy Recovery Company, or PERC, Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee, Hsin Yu, LSP Energy (Batesville) and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha and NEO Tajiguas LLC). All discontinued operations were sold prior to December 31, 2004.

Regional Discussion

Northeast Region Results

Operating Income

For the six months ended June 30, 2005, operating income for the Northeast region was $73.3 million, as compared to $141.9 million for the same period in 2004. The year began with mild temperatures for the winter months and spring, where in the Northeast region temperatures ranged from -7.5ºF to +4.5ºF from the average, whereas in June, the Northeast region had significant heat, up to 9ºF above average[1]. With gas prices 13.6%[2] higher than the first six months of 2004, spark spreads, and to a lesser extent coal dark spreads, were strong, while oil spreads were compressed relative to the first six months of June 2004. The Northeast's New York City assets benefited from the increased spark spreads as they doubled their generation output versus last year, from 0.4 million MWh to 0.8 million MWh. Generation from the NEPOOL assets increased by 37.7%, but oil margins decreased by over 50% versus the first six months of 2004, as our cost per MWh increased by 24% in comparison to the same period in 2004. Additionally, the Northeast recorded $33.1 million of net unrealized losses associated with forward sales of electricity supporting our Northeast assets. Operating income results for the Northeast were also negatively impacted by increases in non-fuel operating expenses. This is due to the increased number of planned and unplanned outages for the six months ended June 30, 2005 versus the same period in 2004.

Revenues

Revenues from our Northeast region totaled $648.1 million for the six months ended June 30, 2005 compared to $605.6 million for the six months ended June 30, 2004. Revenues for the six months ended June 30, 2005 included $513.2 million in energy revenues compared to $442.3 million for the same period in 2004. Of this $70.9 million increase, $61.7 million and $23.3 million can be attributed to our New York City and NEPOOL assets, respectively. Our New York City assets doubled their generation for the six months ended June 30, 2005 as compared to 2004, while our NEPOOL assets increased their generation by 37.7%. The increased generation from these assets are due to outages of local competitors during the period and to the significant heat in June. This was offset by lower energy revenues from our Western New York assets, because of scheduled and unscheduled outages during the first six months of 2005. Capacity revenues for the six months ended June 30, 2005 were $137.7 million compared to $130.7 million for the six months ended June 30, 2004. Capacity revenues were favorable versus the last year due to $23.9 million additional capacity revenues recorded during the second quarter of 2005 related to our Connecticut RMR settlement agreement approved by FERC on January 22, 2005. These settlement revenues were offset, however, by lower capacity revenues from our Western New York plants. Capacity prices in this region were negatively impacted by the addition of new capacity supply and increased imports into New York. Other revenues include derivative and financial revenues, natural gas sales, Fresh Start-related contract amortization, and expense recovery revenues. For the six months ended June 30, 2005, other revenues totaled a loss of $3.1 million compared to $32.6 million of other revenues for the six months ended June 30, 2004. Other revenues were adversely impacted by the lower expense recovery revenues related to the Connecticut RMR agreement of $14.5 million and $33.1 million in mark-to-market unrealized losses in the first half of 2005. These mark-to-market unrealized losses were partly offset by less contract amortization in 2005 versus 2004 and gains realized on hedge transactions booked to financial revenues as compared to the six months ended June 30, 2004.

Operating Expenses

Operating expenses for the six months ended June 30, 2005 were $574.8 million or 89% of the Northeast's revenues, as compared to $463.4 million or 77% of revenues for the six months ended June 30, 2004. The increase in operating expenses is primarily driven by the increase in the cost of energy. Fuel costs in the Northeast were $342.7 million as compared to $259.2 million in 2004. Oil fuel costs in our Northeast region increased by $49.5 million, where 61% of the increase was due to increased generation. Gas fuel costs for our Northeast region increased by $40.9 million, due to 100% higher generation from our New York City plants. Coal costs increased by $9.1 million, due to increased costs, as our coal-fired generation in the Northeast decreased for the first six months of 2005 as compared to 2004, with outages at our Western New York and Indian River facilities. Indian River was particularly impacted by the rising coal costs. Indian River burns eastern coal which has experienced high price volatility versus western coal. As such, this plant was more adversely affected by the overall increase in coal prices.

O&M for our Northeast region was $133.3 million for the six months ended June 30, 2005 as compared to $119.2 million in the six months ended June 2004. The low-sulfur conversion projects continue at our Western New York plants and began at our Indian

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1 Information available from the National Climatic Data Center of the National Oceanic & Atmospheric Administration, or NOAA

2 Per the Henry Hub gas price index published by *Platts Gas Daily*

River plant this year. Additionally, major outages related to turbine overhauls took place at our Western New York and Indian River plants. Other operating expenses for the Northeast region include the administrative regional office costs, insurance and corporate allocations. Other operating costs totaled $194.9 million for the six months ended June 30, 2005 as compared to $168.2 million in 2004. This increase is due to the increase in the corporate allocations per our new allocation methodology as discussed in Note 10, *Segment Reporting*, to the Condensed Consolidated Financial Statements. Additionally, the Northeast's regional office costs were largely recorded as corporate costs in 2004.

South Central Region Results

Operating Income

For the six months ended June 30, 2005, the South Central region realized operating income of $6.8 million, as compared to $31.4 million for the six months ended June 30, 2004. During the first six months of the 2005, our Big Cajun II facility experienced several forced outages. Generation for the first six months of 2005 decreased by 5% from 4.9 to 4.8 million MWh versus the same period in 2004. These outages required the purchase of additional energy to meet its contract load-following obligation in the merchant market at costs higher than our coal-based generating assets. During the first six months of 2005, South Central had two planned outages versus one major outage during the first six months of 2004, which increased major maintenance by $7.9 million as compared to the six months ended June 30, 2004.

Revenues

Revenues from our South Central region were $226.1 million for the six months ended June 30, 2005 compared to $197.8 million for the six months ended June 30, 2004. Revenues for the six months ended June 30, 2005 included $128.8 million in energy revenues, of which 69% were contracted. This compares to $99.8 million of energy revenues for the six months ended June 30, 2004, 75% of which were contracted. South Central energy revenues were favorably impacted by increased merchant energy sales. In addition, merchant energy sales were favorable versus last year due to higher power prices, favorable weather, and nuclear plant outages in the region. Capacity revenues were $90.8 and $89.8 million in the six months ended June 30, 2005 and 2004, respectively. Capacity revenues are fully contracted. Other revenues include derivative and financial revenues and Fresh Start-related contract amortization. For the six months ended June 30, 2005, other revenues totaled $6.4 million compared to $8.1 million for the six months ended June 30, 2004, with the decrease attributable to lower contract amortization and lower coal sales.

Operating Expenses

Operating expenses for the six months ended June 30, 2005 were $219.2 million or 97% of South Central's revenues, as compared to $164 million or 83% of revenues for the six months ended June 30, 2004. The increase of operating expenses is primarily driven by increased fuel costs. Total cost of energy in South Central was $138 million as compared to $98.5 million in 2004. Of this $39.5 million increase, $32.1 million is due to higher purchased energy costs as compared to the six months ended June 30, 2004. Over the first six months of 2005, our Big Cajun II facility experienced a number of forced outages, requiring the purchase of energy to meet contract load obligations. Purchased energy per MWh hour increased by 20% versus the same period in 2004, from $45 to $54.14. O&M for our South Central region was $29 million for the six months ended June 30, 2005 as compared to $20.7 million in the comparable period in 2004. The increase in O&M is related to increased major maintenance. During the first six months of 2005, South Central had two planned outages versus one major outage during the first six months of 2004. Other operating expenses for South Central for the six months ended June 30, 2005 were $51.0 million as compared to $34.0 million for the six months ended June 30, 2004. The increase is largely due to the new NRG allocations methodology as discussed in Note 10, *Segment Reporting*, to the Condensed Consolidated Financial Statements. Additionally, much of the South Central regional office had been recorded as corporate costs in the second quarter of 2004.

Western Region Results

For the six months ended June 30, 2005, the Western region realized an operating loss of $3.3 million, as compared to an operating loss of $6.5 million for the six months ended June 30, 2004. The primary driver of the lower operating loss is related to the payment of CAISO penalties paid by our Red Bluff and Chowchilla facilities in 2004, offset by the expiration of the Red Bluff RMR contract as of December 31. 2004.

Other North America Region Results

For the six months ended June 30, 2005, the Other North America region realized an operating loss of $7.9 million on revenues of $14.8 million, as compared to operating income of $11.1 million and revenues of $50.4 million for the six months ended June 30, 2004. This unfavorable variance is primarily related to the sale of Kendall. Kendall had operating income of $14.1 million and revenues of $37.2 million in the six months ended June 30, of 2004. Operating expenses and depreciation and amortization for our Other North America region for the six months ended June 30, 2005 were $18.7 million and $4 million, respectively. For the six months ended June 30, 2004, operating expenses and depreciation and amortization were $24.6 million and $14.5 million, respectively. The favorable variance in both of these is driven by the sale of Kendall, with the variance in operating expense partially offset by a bad debt allowance of $2.2 million recorded in 2005 for a receivable due from a third-party.

Australia Region Results

Operating Income

For the six months ended June 30, 2005, the Australia region realized an operating loss of $0.9 million, as compared to $5.6 million in operating income for the six months ended June 30, 2004. Unseasonably mild weather and weak pool prices in the first quarter drove the unfavorable results as compared to last year. Higher generation helped to offset weak pool prices, with generation increasing 6.0% over the generation from the first six months of 2004.

Revenues

Revenues from our Australia region totaled $105.9 million for the six months ended June 30, 2005 compared to $99.0 million for the six months ended June 30, 2004. Revenues for the six months ended June 30, 2005 included $68.1 million in energy revenues compared to $82.3 million of energy revenues for the six months ended June 30, 2004. These unfavorable results versus 2004 were largely driven by weak pool prices, partially offset by the increased generation. An unseasonably mild summer in Australia drove the average pool price down to $24.53 per MWh from $31.58 per MWh in the first six months of 2005, a reduction of 22% versus the first six months in 2004. Due to the full commercialization of the Playford station, generation for the six months ended June 2005 was 1.4 million MWh which was slightly ahead of the 1.3 million MWh generated in the same period of 2004. For the six months ended June 30, 2005, other revenues totaled $37.8 million compared to $16.7 million of other revenues for the six months ended June 30, 2004. Other revenues were favorably impacted by lower contract amortization of $9.4 million and $7.7 million of gains realized on hedge transactions booked to financial revenues as compared to the six months ended June 30, 2004.

Operating Expenses

Operating expenses for our Australia region for the six months ended June 30, 2005 were $94.1 million, as compared to $81.4 million, for the six months ended June 30, 2004. Fuel costs and purchased energy accounted for $5.1 million of the increase and higher O&M costs account for $3.7 million of the increase. These increases are due to the additional costs of the Playford Station, which was not fully commercialized during the same period in 2004. Other operating expenses for Australia for the six months ended June 30, 2005 increased over the same period in 2004 due to the new NRG allocations methodology as discussed in Note 10, *Segment Reporting*, to the Condensed Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND CHANGES IN ACCOUNTING STANDARDS

Our discussion and analysis of our financial condition and results of operations are based upon our 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 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 impact 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, we evaluate our estimates, utilizing historic experience, consultation with experts and other methods we consider reasonable. In any case, actual results may differ significantly from our estimates. Any effects on our 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.

See Note 2, *Summary of Significant Accounting Policies,* to the Condensed Consolidated Financial Statements for details of changes in accounting standards.

LIQUIDITY AND CAPITAL RESOURCES

In December 2004, we issued $420.0 million of convertible preferred stock and used the proceeds from such issuance to redeem $375.0 million of the Second Priority Notes in February 2005. Also in January 2005 and in March 2005, we used existing cash to purchase, at market prices, $25.0 million and $15.8 million, respectively, in face value of our Second Priority Notes. These notes are held in treasury by NRG Energy. As of June 30, 2005 and August 3, 2005, we had $1.31 billion in aggregate principal amount of Second Priority Notes, excluding those held in treasury, $447.8 million in principal amount outstanding under the term loan and $350.0 million of the funded letter of credit facility outstanding. As of August 3, 2005, $161.6 million of undrawn letters of credit capacity remain available under the funded letter of credit facility, and we had not drawn down on our revolving credit facility.

In connection with our power generation business, we manage the commodity price risk associated with our supply activities and our electric generation facilities. This includes forward power sales, fuel and energy purchases and emission credits. In order to manage these risks, we enter into financial instruments to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel and energy. We utilize a variety of instruments including forward contracts, future contracts, swaps and options. Certain of these contracts allow counterparties to require NRG to post margin collateral. As of June 30, 2005 and August 3, 2005, we have posted $205.7 million and $306.4 million, respectively, in collateral to support these contracts.

Capital Expenditures

Capital expenditures were approximately $36.5 million and $64.7 million for the three and six months ended June 30, 2005 and June 30, 2004, respectively. We anticipate that our 2005 capital expenditures will be approximately $125 million and will relate to the operation and maintenance of our existing generating facilities.

Liquidity

As of June 30, 2005 our liquidity was $1.2 billion and includes $910 million of unrestricted and restricted cash. Our liquidity also includes $150.0 million of available capacity under our revolving line of credit and $171.5 million of availability under our letter of credit facility. As of December 31, 2004 our liquidity was $1.6 billion and included $1.2 billion of unrestricted and restricted cash. Our liquidity also included $150.0 million of available capacity under our revolving line of credit and $192.9 million of availability under our letter of credit facility.

NRG has committed to repurchase, on August 11, 2005, $250 million of NRG's outstanding common stock from an affiliate of Credit Suisse First Boston LLC, or CSFB. NRG will fund the planned repurchase with existing cash balances. To enable this share repurchase under NRG's high yield debt indenture, NRG will issue simultaneously in a private transaction, $250 million of perpetual preferred stock. On August 5, 2005, NRG obtained an amendment to its corporate credit agreement which allowed NRG to use cash proceeds from the preferred issuance to repurchase approximately $229 million of our 8% high yield notes at 108% of par.

Other Liquidity Matters — NOLs, Deferred Tax Assets and Repatriation of Foreign Funds

As of June 30, 2005, we have a US NOL carryforward of $18.5 million which will expire through 2024. We believe that it is more likely than not that benefit will not be realized on the deferred tax assets relating to the NOL carryforwards. This assessment included consideration of positive and negative factors, including our current financial position and results of operations, projected future taxable income, including projected operating and capital gains, and available tax planning strategies. Therefore, as of June 30, 2005, a consolidated valuation allowance of $725.3 million was recorded against the net deferred tax assets, including NOL carryforwards in accordance with SFAS No. 109.

Pending our evaluation of the American Jobs Creation Act of 2004, management intends to indefinitely reinvest the earnings from our foreign operations. Currently, our management is reviewing our reinvestment plan pursuant to the Act which provides for a low tax cost on earnings repatriated in 2005 and reinvested in the company's U.S. operations. We are presently estimating a maximum cash balance amount of $307 million which could be remitted from foreign operations to the U.S. by year end and resulting in a federal tax cost of 5.25% under the Act to the extent the Company has earnings and profits. Pending our conclusive evaluation of the Company's cumulative earnings and profits position, we cannot assess the range of income tax cost at this time.

As of June 30, 2005, there is no tax effect resulting from this legislation since management has not concluded upon a repatriation plan. The Company expects to conclude on this issue by the fourth quarter of 2005.

Cash Flows

	For the Six Months Ended	
	June 30, 2005	June 30, 2004
	(In thousands)	
Net cash provided by operating activities	91,519	317,357
Net cash provided by investing activities	148,546	1,558
Net cash used in financing activities	(527,265)	(85,672)

Net Cash Provided By Operating Activities

For the six months ended June 30, 2005, cash provided by operating activities was $91.5 million, a decrease of $225.8 million from the six months ended June 30, 2004. The main contributors to the decrease were a net receipt of $125 million during the six months ended June 30, 2004 related to a bankruptcy-related net receivable and cash payments of $157 million during the six months ended June 30, 2005 for cash collateral to support the trading activities by our Power Marketing group. These amounts are offset by the receipt of $22 million in refundable tax credits during 2005, a $9 million increase in distributions from WCP above equity earnings and other working capital movement.

Net Cash Provided By Investing Activities

For the six months ended June 30, 2005, cash provided by investing activities was $148.5 million, an increase of $146.9 million from the six months ended June 30, 2004. During the six months ended June 30, 2005 we received $64.6 million for the sale of Enfield and $70.8 million related to the TermoRio settlement. During the same period in 2004, we received $88.9 million for the sale of equity method investments and discontinued operations. In 2005, cash from investing increased as restrictions on cash were released, primarily as a result of our refinancing of Flinders' debt. At Flinders, restricted cash was reduced by $38.2 million in 2005, compared to an increase of $10.5 million in 2004. During 2004 there were additional movements of cash into restricted accounts by Batesville in the amount of $10 million and a one time increase of $16.1 million at our Peakers Finance Company, or Peakers, that did not recur in 2005. Batesville was sold during 2004 and the increase at Peakers was a one time catch-up following the project level debt restructuring.

Our capital expenditures for the six months ended June 2005 are $28.1 million less than year-to-date June 2004 as a result of the refurbishment of our Playford station in Australia during 2004, and a major maintenance project in 2004 at our Big Cajun II which qualified as a capital expenditure.

Net Cash Used in Financing Activities

For the six months ended June 30, 2005, cash used by financing activities was $527.3 million, an increase of $441.6 million compared to a use of $85.7 million in the same period last year. The activity for the six months ended June 30, 2005 consists of the redemption and repurchase of $415.8 million of our Second Priority Secured Notes and the refinancing our Flinders' debt, which resulted in a net prepayment of $57.2 million and an increase in deferred financing costs of $1.6 million. During the second quarter of 2005, we repaid an additional $10 million of our Flinders' debt. For the six months ended June 30, 2004, cash used by financing activities of $85.7 million reflects normal scheduled principal payments. In addition, during the same period, we refinanced our term loan facility with an additional $475.0 million of Second Priority Secured Notes at a premium of $28.5 million. Proceeds from this offering were used to repay $503.5 million of our then recently issued term loan.

OFF-BALANCE SHEET ARRANGEMENTS

Obligations Under Certain Guarantee Contracts

NRG Energy and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Note 29, *Guarantees and Other Contingent Liabilities*, to the Company's financial statements in our Annual Report on Form 10-K for the year ended December 31, 2004, and Note 14, *Guarantees*, to the Condensed Consolidated Financial Statements for further details of the guarantee arrangements.

Retained or Contingent Interests

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

Derivative Instruments obligations

As of June 30, 2005, NRG does not have any contracts that would have been accounted for as a derivative instrument, except that it is both indexed to our own stock and classified as stockholder's equity, and therefore excluded from the scope of SFAS No. 133 pursuant to paragraph 11(a).

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

As of June 30, 2005, we have not entered into any financing structure that is designed to be off-balance sheet that would create liquidity, financing or incremental market risk or credit risk to us. However, we have numerous investments with an ownership interest percentage of 50% or less in energy and energy related entities that are accounted for under the equity method of accounting. Our pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $199.2 million and $251.7 million as of June 30, 2005 and December 31, 2004, respectively. In the normal course of business we may be asked to loan funds to unconsolidated affiliates on both a long and short-term basis. Such transactions are generally accounted for as accounts payable and receivable to/from affiliates and notes payable/receivable to/from affiliates and if appropriate, bear market-based interest rates.

Contractual Obligations and Commercial Commitments

We have a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to our capital expenditure programs, as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2004.

In August 2004, we entered into a contract to purchase 1,540 aluminum railcars from Freight Car America, formerly Johnstown America Corporation to be used for the transportation of low sulfur coal from Wyoming to NRG's coal burning generating plants, including our New York and South Central facilities. On February 18, 2005, we entered into a ten-year operating lease agreement with GE for the lease of 1,500 railcars. Delivery of the railcars from Freight Car America commenced in February 2005 and is expected to be completed by August 2005. We have assigned certain of our rights and obligations for 1,500 railcars under the purchase agreement with Freight Car America to GE. Accordingly, the railcars which we lease from GE under the arrangement described above will be purchased by GE from Freight Car America in lieu of our purchase of those railcars.

In December 2004, we entered into a long-term coal transport agreement with the Burlington Northern and Santa Fe Railway Company and affiliates of American Commercial Lines LLC to deliver low sulfur coal to our Big Cajun II facility in New Roads, Louisiana beginning April 1, 2005. In March 2005, we entered into an agreement to purchase coal over a period of four years and nine months from Buckskin Mining Company, or Buckskin. The coal will be sourced from Buckskin's mine in the Powder River Basin, Wyoming, and will be used primarily in NRG's coal-burning generation plants in the South Central region of the United States. Including this contract and other contracts, total coal purchase obligations increased by $174.4 million, which are expected to be paid over the course of the next two years.

In April 2005, we amended our contract for a five-year coal rail transportation agreement with CSX Transportation, Inc. and Union Pacific Railroad Company, to deliver low sulfur coal to our Dunkirk and Huntley facilities in Buffalo, New York, beginning April 1, 2005. Although the amendment does not change our minimum financial commitments, we are now obligated to transport at least 95% of our coal supplies for our Dunkirk and Huntley facilities with CSX Transportation, Inc. and Union Pacific Railroad Company.

Commitments and Contingencies

See Note 13, *Commitments and Contingencies*, to the Condensed Consolidated Financial Statements for a discussion of commitments and contingencies.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to several market risks in our normal business activities. Market risk is the potential loss that may result from market changes associated with our "merchant" power generation or with an existing or forecasted financial or commodity transaction. The types of market risks we are exposed to are commodity price risk, interest rate risk and currency exchange risk. In order to manage these risks we utilize 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 our fixed-price purchase and sales commitments;
- Manage and hedge our exposure to variable rate debt obligations;
- Reduce our exposure to the volatility of cash market prices; and
- Hedge our fuel requirements for our generating facilities.

Commodity Price Risk

Commodity price risks result from exposures to changes in spot prices, forward prices, volatilities 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,
- Changes in the nature and extent of federal and state regulations.

As part of our overall portfolio, we manage the commodity price risk of our "merchant" generation 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, operational, and other factors.

While some of the contracts we use 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. We use our best estimates to determine the fair value of commodity and derivative contracts we hold and sell. 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.

We measure the sensitivity of our portfolio to potential changes in market prices using value at risk. Value at risk is a statistical model that attempts to predict risk of loss based on market price volatility. We calculate value at risk using a variance/covariance technique that models positions using a linear approximation of their value. Our value at risk calculation includes mark-to-market and non mark-to-market energy assets and liabilities.

We utilize a diversified value at risk model to calculate the estimate of potential loss in the fair value of our energy assets and liabilities including generation assets, load obligations and bilateral physical and financial transactions. The key assumptions for our diversified model include (1) a lognormal distribution of price returns, (2) one-day holding period, (3) a 95% confidence interval, (4) a rolling 24-month forward looking period and (5) market implied price volatilities and historical price correlations.

This model encompasses all of our generating assets in the following regions: California, ENTERGY, NEPOOL, NYISO and PJM. The estimated maximum potential loss in fair value of our commodity portfolio, including generation assets, load obligations and bilateral physical and financial transactions calculated using the diversified VAR model is as follows:

	(In millions)
Quarter ended June 30, 2005	$ 20.6
Average	21.5
High	25.3
Low	14.6

	(In millions)
Year ended December 31, 2004	26.7
Average	40.3
High	53.4
Low	26.7

In order to provide additional information for comparative purposes to our peers we also utilize value at risk to model the estimate of potential loss of financial derivative instruments included in derivative instruments valuation of assets and liabilities. This estimation includes those energy contracts accounted for as a hedge under SFAS No. 133, as amended. The estimated maximum potential loss in fair value of the financial derivative instruments calculated using the diversified VAR model as of June 30, 2005 is $29.1 million.

Due to the inherent limitations of statistical measures such as value at risk, the relative immaturity of the competitive markets for electricity and related derivatives, and the seasonality of changes in market prices, the value at risk calculation may not capture the full extent of commodity price exposure. Additionally, actual changes in the value of options may differ from the value at risk calculated using a linear approximation inherent in our calculation method. As a result, actual changes in the fair value of mark-to market energy assets and liabilities could differ from the calculated value at risk, and such changes could have a material impact on our financial results.

Interest Rate Risk

We are exposed to fluctuations in interest rates through our 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. Our risk management policy allows us to reduce interest rate exposure from variable rate debt obligations.

As of June 30, 2005, we had various interest rate swap agreements with notional amounts totaling approximately $1.2 billion. If the swaps had been discontinued on June 30, 2005, we would have owed the counter-parties approximately $32.2 million. Based on the investment grade rating of the counter-parties, we believe that our exposure to credit risk due to nonperformance by the counter-parties to our hedging contracts is insignificant.

We have both long and short-term debt instruments that subject us to the risk of loss associated with movements in market interest rates. As of June 30, 2005, a 100 basis point change in interest rates would result in a $6.2 million change in interest expense on a rolling twelve month basis.

At June 30, 2005, the fair value of our long-term debt was $3.3 billion, compared with the carrying amount of $3.2 billion. We estimate that a 1% decrease in market interest rates would have increased the fair value of our long-term debt by $54.7 million.

Currency Exchange Risk

We expect to continue to be subject to currency risks associated with foreign denominated distributions from our international investments. In the normal course of business, we may receive distributions denominated in the Euro, Australian Dollar and the Brazilian Real. As of June 30, 2005, neither we, nor any of our consolidating subsidiaries, had any material outstanding foreign currency exchange contracts.

Credit Risk

Credit risk relates to the risk of loss resulting from non-performance or non-payment by counter-parties pursuant to the terms of their contractual obligations. We monitor and manage the credit risk of NRG Energy, Inc. and its subsidiaries through credit policies which include an (i) established credit approval process, (ii) daily monitoring of counter-party 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 counter-party. Risks surrounding counter-party performance and credit could ultimately impact the amount and timing of expected cash flows. We have credit protection within various agreements to call on additional collateral support if necessary. As of June 30, 2005 and August 3, 2005, we held collateral support of $178.7 million and $179.5 respectively, from counter-parties.

Additionally NRG has concentrations of suppliers and customers among electric utilities, energy marketing and trading companies and regional transmission operators, particularly NYISO and ISO-NE. NYISO and ISO-NE are ISO's or RTO's that act as clearing agents for market participants in their specific control area, thereby diffusing credit risk by requiring collateralization based on their respective financial assurance policies as approved by regulatory authorities. These concentrations of counter-parties may impact NRG's overall exposure to credit risk, either positively or negatively, in that counter-parties may be similarly affected by changes in economic, regulatory and other conditions.

Significant Customers

For the six months ended June 30, 2005, we derived approximately 44.3% of our total revenues from majority-owned operations from two customers: NYISO accounted for 31.8% and ISO New England accounted for 12.5%. We account for the revenues attributable to NYISO and ISO-NE as part of our North American power generation segment. ISO-NE and NYISO are ISOs or RTOs and are FERC-regulated entities that administer day-ahead and real-time energy markets, capacity and ancillary service markets and manage transmission assets collectively under their respective control to provide non-discriminatory access to the transmission grid. The NYISO exercises operational control over most of New York State's transmission facilities. ISO-NE has operational control over most of the New England transmission systems. We anticipate that NYISO and ISO-NE will continue to be significant customers given the scale of our asset base in these areas.

Fair Value of Derivative Instruments

As the Company engages principally in the trading and marketing of its generation assets, most of our commercial activities qualify for hedge accounting under the requirements of SFAS No.133. In order to so qualify, the physical generation and sale of electricity must be highly probable at inception of the trade and throughout the period it is held, as is the case with our base-load coal plants. For this reason, trades in support of the company's peaking units will not generally qualify for hedge accounting treatment and any changes in fair value are likely to be reflected on a mark-to-market basis in the statement of operations. The majority of trades in support of our base-load coal units will normally qualify for hedge accounting treatment and any fair value movements will be reflected in the balance sheet as part of Other Comprehensive Income.

As part of the trading and marketing of our generation assets, we may enter into forward power sales contracts, forward gas purchase contracts and other energy related commodities financial instruments to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect fuel inventories. In addition, in order to mitigate interest rate risk associated with the issuance of our variable rate and fixed rate debt, we enter into interest rate swap agreements.

The tables below disclose the derivative contracts accounted for at fair value. Specifically, these tables disaggregate realized and unrealized changes in fair value; identify changes in fair value attributable to changes in valuation techniques; disaggregate estimated fair values at June 30, 2005 based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at June 30, 2005.

Derivative Activity Gains/(Losses)

	(In thousands)
Fair value of contracts at December 31, 2004	$ (43,671)
Contracts realized or otherwise settled during the period	(68,197)
Changes in fair value	(98,280)
Fair value of contracts at June 30, 2005	$ (210,148)

Sources of Fair Value Gains/(Losses)

	Fair Value of Contracts at Period End as of June 30, 2005				
	Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in excess of 5 Years	Total Fair Value
			(In thousands)		
Prices actively Quoted	$(62,234)	$(27,611)	$ —	$ —	$ (89,845)
Prices based on models and other valuation methods	(3,575)	(22,871)	(14,875)	(27,964)	(69,285)
Prices provided by other external sources	(14,935)	(6,952)	(5,415)	(23,716)	(51,018)
Total	$(80,744)	$(57,434)	$ (20,290)	$(51,680)	$(210,148)

We may use a variety of financial instruments to manage our exposure to fluctuations in foreign currency exchange rates on our international project cash flows, interest rates on our cost of borrowing and energy and energy related commodities prices.

Item 4. Controls and Procedures

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

As indicated in the certification accompanying the signature page to this report, the Certifying Officers have certified that, to the best of their knowledge, the consolidated financial statements, and other financial information included in this report on Form 10-Q, fairly present in all material respects the financial conditions, results of operations and cash flows of NRG Energy, Inc. as of, and for the periods presented in this report.

There have not been any changes in our 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 fiscal quarter to which this report relates that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting.

Part II — OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of material legal proceedings in which we were involved through June 30, 2005, see Note 13, *Commitments and Contingencies*, to our condensed consolidated financial statements contained in Part I, Item 1 of this Form 10-Q.

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 Energy, Inc. voted on four items at the Annual Meeting of Stockholders held on May 24, 2005:

1. The election of Class II Directors to a three-year term.
2. The proposal to approve an amendment to Article Seven of the Amended and Restated Certification of Incorporation.
3. The proposal to approve an amendment deleting Article Sixteen of the Amended and Restated Certificate of Incorporation.
4. The proposal to ratify the appointment of KPMG LLP as NRG's independent registered public accounting firm.

There were 87,456,104 shares of common and preferred stock entitled to vote at the meeting and a total of 72,607,900 shares (83.41%) were represented at the meeting.

The three individuals named below were elected to serve a three-year term as Class II Directors expiring at the annual meeting of stockholders in 2008:

Nominee	Votes For	Votes Withheld
Lawrence S. Coben	71,307,302	1,300,598
Herbert H. Tate	72,451,302	156,598
Walter R. Young	72,451,602	156,298

The proposal to approve the amendment to Article Seven of the Amended and Restated Certificate of Incorporation was approved with 70,071,754 shares voting for, 2,522,991 shares voting against, 13,155 shares abstaining and zero broker non-votes.

The proposal to approve the amendment deleting Article Sixteen of the Amended and Restated Certificate of Incorporation was approved with 72,548,334 shares voting for, 40,860 shares voting against, 18,706 shares abstaining and zero broker non-votes.

The proposal to ratify the appointment of KPMG LLP as independent registered public accounting firm was ratified with 71,955,548 shares voting for, 646,011 shares voting against, 6,341 shares abstaining and zero broker non-votes.

Item 5. Other Information

NRG has changed the date of its 2006 Annual Meeting of Stockholders from May 23, 2006, as set forth in its Proxy Statement filed April 12, 2005, to April 27, 2006.

NRG has committed to repurchase, on August 11, 2005, $250 million of NRG's outstanding common stock from an affiliate of Credit Suisse First Boston LLC, or CSFB. NRG will fund the planned repurchase with existing cash balances. To enable this share repurchase under NRG's high yield debt indenture, NRG will issue simultaneously in a private transaction, $250 million of perpetual preferred stock. On August 5, 2005, NRG obtained an amendment to its corporate credit agreement which allowed NRG to use cash proceeds from the preferred issuance to repurchase approximately $229 million of our 8% high yield notes at 108% of par.

Item 6. Exhibits

(a) Exhibits

10.1 Form of NRG Energy, Inc. Long Term Incentive Plan Performance Unit Agreement

10.2 First Amendment, dated as of August 5, 2005, to the Credit Agreement, dated as of December 23, 2003, as amended and restated as of December 24, 2004, by and among NRG Energy, Inc., NRG Power Marketing Inc., the lenders from time to time party thereto, Credit Suisse First Boston, acting through its Cayman Islands Branch, and Goldman Sachs Credit Partners L.P., as joint lead book runners, joint lead arrangers and co-documentation agents, Credit Suisse First Boston, acting through its Cayman Islands Brand, as administrative agent and collateral agent, and Goldman Sachs Credit Partners L.P., as syndication agent.

31.1 Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.3 Certification of Controller pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32 Certification of Chief Executive Officer, Chief Financial Officer and Controller pursuant to Section 906 of the Sarbanes- Oxley Act of 2002, 18 U.S.C. Section 1350.

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 CRANE

David Crane,
Chief Executive Officer

/s/ ROBERT C. FLEXON

Robert C. Flexon,
Chief Financial Officer
(Principal Financial Officer)

/s/ JAMES J. INGOLDSBY

James J. Ingoldsby,
Controller
(Principal Accounting Officer)

Date: August 9, 2005

Exhibit Index

Exhibits

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NRG ENERGY, INC. LONG-TERM INCENTIVE PLAN
PERFORMANCE STOCK UNIT AGREEMENT

«First_Name» «Last_Name» «Suffix»
«Address»
«City», «State» «Zip»

Congratulations on your selection as a Participant under the NRG Energy, Inc. Long-Term Incentive Plan ("Plan"). You have been chosen by NRG Energy, Inc. (the "Company") to receive Performance Stock Units ("PUs") under the Plan.

This Performance Stock Unit Agreement (this "Agreement") constitutes the Grant Agreement pursuant to Section 9 of the Plan. If there is any inconsistency between the terms of this Agreement and the terms of the Plan, the Plan's terms shall completely supersede and replace the conflicting terms of this Agreement. Capitalized terms used but not defined in this Agreement shall have the meaning assigned to them in the Plan. You are sometimes referred to as the "Participant" in this Agreement.

PLEASE NOTE THAT BY SIGNING THIS AGREEMENT YOU ARE ACKNOWLEDGING THAT YOU AGREE TO BE BOUND BY THE TERMS OF THIS AGREEMENT AND THE PLAN, INCLUDING WITHOUT LIMITATION TERMS AND CONDITIONS THAT MAY LIMIT YOUR ABILITY TO PURCHASE THE COMMON STOCK UNDERLYING THE PUs GRANTED IN THIS AGREEMENT.

1. Grant of PU.

You are hereby granted PUs as follows:

Date of Grant:	August 1, 2005
Vesting Commencement Date:	Date of Grant
Vesting Period:	Please refer to Section 2 of this Agreement
Total Number of PUs:	«PUs»

2. Vesting Schedule.

Provided that you have been continuously employed by the Company during the vesting period, the PUs will vest on the third anniversary of the Date of Grant based on NRG's Total Shareholder Return, in accordance with the following schedule:

Threshold	Stock Price	Cost of Equity	Payout *
Maximum	$ 63.75	18.0%	**200% of Target** = Number of PUs in Section 1 of this agreement multiplied by 2.
Target	$ 54.50	12.0%	**100% of Target** = Number of PUs in Section 1 of this agreement.
< Target	< $54.50	< 12.0%	**0% of Target** = Number of PUs in Section 1 multiplied by 0.

* Payout (# of PUs) is interpolated for performance falling between Target and Maximum levels.

Notwithstanding the foregoing, if there is a Change in Control (as defined in the Plan) of the Company, the PUs shall vest in full immediately upon such Change in Control.

3. Conversion of PU and Issuance of Shares

Upon vesting of the Award, one share of Common Stock shall be issued for each PU that vests on such vesting date, subject to the terms and conditions of this Agreement and the Plan.

4. Transfer of PUs

Unless otherwise permitted by the Committee or Section 14 of the Plan, the PUs may not be sold, transferred, pledged, assigned or otherwise alienated or hypothecated, other than pursuant to a will or the laws of descent and distribution. Any attempted disposition in violation of this Section 4 or Section 14 of the Plan shall be void.

5. Status of Participant

The Participant shall not be, or have rights as, a stockholder of the Company with respect to any of the shares of Common Stock subject to the Award unless such Award has vested, and shares underlying the PU have been issued and delivered to him or her. The Company shall not be required to issue or transfer any certificates for shares of Common Stock upon vesting of the Award until all applicable requirements of law have been complied with and such shares have been duly listed on any securities exchange on which the Common Stock may then be listed.

6. No Effect on Capital Structure

The Award shall not affect the right of the Company or any Subsidiary to reclassify, recapitalize or otherwise change its capital or debt structure or to merge, consolidate, convey any or all of its assets, dissolve, liquidate, windup, or otherwise reorganize.

7. Expiration and Forfeiture of Award

Your Award shall vest and/or expire in the circumstances described below in this Section 7. As used herein, "***Termination of Service***" means termination of a Participant's employment by or service to the Company, including any of its Subsidiaries.

(a) Death.

Upon a Termination of Service by reason of death, the Award shall vest in full and the Common Stock underlying the Award shall be issued and delivered to the Participant's legal representatives, heirs, legatees, or distributees.

(b) Termination of Service other than as a result of Death.

Upon a Termination of Service by any reason other than death, including without limitation as a result of Disability, Retirement, voluntary resignation or termination for Cause, any unvested portion of the Award shall expire and be forfeited to the Company.

8. Committee Authority

Any question concerning the interpretation of this Agreement, any adjustments required to be made under the Plan, and any controversy that may arise under the Plan or the Grant Agreement shall be determined by the Committee in its sole discretion. Any decisions by the Committee regarding the Plan or this Agreement shall be final and binding.

9. Plan Controls

The terms of this Agreement are governed by the terms of the Plan, as it exists on the date of the grant and as the Plan is amended from time to time. In the event of any conflict between the provisions of this Agreement and the provisions of the Plan, the terms of the Plan shall control.

10. Limitation on Rights; No Right to Future Grants; Extraordinary Item.

By entering into this Agreement and accepting the Award, the Participant acknowledges that: (a) the Plan is discretionary and may be modified, suspended or terminated by the Company at any time as provided in the Plan, provided that, except as provided in Section 17 of the Plan, no amendment to this Agreement shall adversely affect in a material manner the Participant's rights under this Agreement without his or her written consent; (b) the grant of the Award is a one-time benefit and does not create any contractual or other right to receive future grants of awards or benefits in lieu of awards; (c) all determinations with respect to any such future grants, including, but not limited to, the times when awards will be granted, the number of shares subject to each award, the award price, if any, and the time or times when each award will be settled, will be at the sole discretion of the Company; (d) participation in the Plan is voluntary; (e) the value of the Award is an extraordinary item which is outside the scope of the Participant's employment contract, if any, unless expressly provided for in any such employment contract; (f) the Award is not part of normal or expected compensation for any purpose, including without limitation for calculating any benefits, severance, resignation, termination, redundancy, end of service payments, bonuses, long-service awards, pension or retirement benefits or similar payments, and the Participant will have no entitlement to compensation or damages as a consequence of the forfeiture of any unvested portion of the Award as a result of the Participant's Termination of Service for any reason; (g) the future value of the Common Stock subject to the Award is unknown and cannot be predicted with certainty, (h) neither the Plan, the Award nor the issuance of the shares underlying the Award confers upon the Participant any right to continue in the employ or service of (or any other relationship with) the Company or any Subsidiary, nor do they limit in any respect the right of the Company or any Subsidiary to terminate the Participant's employment or other relationship with the Company or any Subsidiary, as the case may be, at any time with or without Cause, and (i) the grant of the Award will not be interpreted to form an employment relationship with the Company or any Subsidiary; and furthermore, the grant of the Award will not be interpreted to form an employment contract with the Company or any Subsidiary.

11. General Provisions

(a) Notice

Whenever any notice is required or permitted hereunder, such notice must be in writing and delivered in person or by mail (to the address set forth below if notice is being delivered to the Company) or electronically. Any notice delivered in person or by mail shall be deemed to be delivered on the date on which it is personally delivered, or, whether actually received or not, on the third business day after it is deposited in the United States mail, certified or registered, postage prepaid, addressed to the person who is to receive it at the address set forth in this Agreement. Notices delivered to the Participant in person or by mail shall be addressed to the address for the Participant in the records of the Company. Notices delivered to the Company in person or by mail shall be addressed as follows:

Company: NRG Energy, Inc.
Attn: Vice President, Human Resources
211 Carnegie Center
Princeton, NJ 08450

The Company or the Participant may change, by written notice to the other, the address previously specified for receiving notices.

(b) No Waiver

No waiver of any provision of this Agreement will be valid unless in writing and signed by the person against whom such waiver is sought to be enforced, nor will failure to enforce any right under this Agreement constitute a continuing waiver of the same or a waiver of any other right hereunder.

(c) Undertaking

The Participant hereby agrees to take whatever additional action and execute whatever additional documents the Company may deem necessary or advisable in order to carry out or effect one or more of the obligations or restrictions imposed on either the Participant or the Award pursuant to the express provisions of this Agreement.

(d) Entire Contract

This Agreement and the Plan constitute the entire contract between the parties hereto with regard to the subject matter hereof. This Agreement is made pursuant to the provisions of the Plan and will in all respects be construed in conformity with the express terms and provisions of the Plan.

(e) Successors and Assigns

The provisions of this Agreement shall inure to the benefit of, and be binding on, the Company and its successors and assigns and Participant and Participant's legal representatives, heirs, legatees, distributees, assigns and transferees by operation of law.

(f) Securities Law Compliance

The Company currently has an effective registration statement on file with the Securities and Exchange Commission with respect to the shares of Common Stock subject to the Award. The Company intends to maintain this registration but has no obligation to the Participant to do so. If the registration ceases to be effective, the Participant will not be able to transfer or sell shares of Common Stock issued pursuant to the Award unless exemptions from registration under applicable securities laws are available. Such exemptions from registration are very limited and might be unavailable. Participant agrees that any resale of the shares of Common Stock issued pursuant to the Award shall comply in all respects with the requirements of all applicable securities laws, rules and regulations (including, without limitation, the provisions of the Securities Act of 1933, the Securities Exchange Act of 1934 and the respective rules and regulations promulgated thereunder) and any other law, rule or regulation applicable thereto, as such laws, rules, and regulations may be amended from time to time. The Company shall not be obligated to either issue shares of Common Stock or permit the resale of any such shares if such issuance or resale would violate any such requirements.

(g) Taxes

Participant acknowledges that the removal of restrictions with respect to an PU will give rise to a withholding tax liability, and that no shares of Common Stock are issuable hereunder until such withholding obligation is satisfied in full. The Participant agrees to remit to the Company the amount of any taxes required to be withheld. The Committee, in its sole discretion, may permit Participant to satisfy all or part of such tax obligation through withholding of the number of shares of Common Stock otherwise issued to him or her hereunder and/or by the Participant transferring to the Company nonrestricted shares of Common Stock previously owned by the Participant for at least six (6) months prior to the vesting of the Award hereunder, with the amount of the withholding to be credited based on the current Fair Market Value of the Common Stock as of the date the amount of tax to be withheld is determined.

(h) Information Confidential

As partial consideration for the granting of the Award, the Participant agrees that he or she will keep confidential all information and knowledge that the Participant has relating to the manner and amount of his or her participation in the Plan; provided, however, that such information may be disclosed as required by law and may be given in confidence to the Participant's spouse, tax and financial advisors, or to a financial institution to the extent that such information is necessary to secure a loan.

(i) Governing Law

Except as may otherwise be provided in the Plan, the provisions of this Agreement shall be governed by the laws of the state of Delaware, without giving effect to principles of conflicts of law.

(j) Code Section 409A Compliance

Notwithstanding any provision of this Agreement, to the extent that the Committee determines that any Award granted under this Agreement is subject to Section 409A of the Code and fails to comply with the requirements of Section 409A of the Code, notwithstanding anything to the contrary contained in the Plan or in this Agreement, the Committee reserves the right to amend, restructure, terminate or replace the Award in order to cause the Award to either not be subject to Section 409A of the Code or to comply with the applicable provisions of such section.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date first written above.

NRG ENERGY, INC.

/s/ David Crane

Name: David Crane

Title: President & CEO

PARTICIPANT:

____

Name: ____________________

Exhibit 10.2

EXECUTION COPY

FIRST AMENDMENT TO CREDIT AGREEMENT

FIRST AMENDMENT dated as of August 5, 2005 (this "First Amendment"), to the Credit Agreement dated as of December 23, 2003, as amended and restated as of December 24, 2004 (as further amended, restated, supplemented or otherwise modified from time to time, the "Credit Agreement"), among NRG ENERGY, INC., a Delaware corporation (the "Company"), NRG POWER MARKETING INC., a Delaware corporation (together with the Company, the "Borrowers"), the LENDERS from time to time party thereto, CREDIT SUISSE FIRST BOSTON, acting through its Cayman Islands Branch, and GOLDMAN SACHS CREDIT PARTNERS L.P., as joint lead book runners, joint lead arrangers and co-documentation agents, CREDIT SUISSE FIRST BOSTON, acting through its Cayman Islands Branch, as administrative agent (in such capacity and together with its successors, the "Administrative Agent") and as collateral agent, and GOLDMAN SACHS CREDIT PARTNERS L.P., as syndication agent.

WHEREAS, the Borrowers and the Administrative Agent, among others, are parties to the Credit Agreement;

WHEREAS, the Borrowers have requested that the Lenders agree to amend certain provisions of the Credit Agreement as set forth in this First Amendment; and

WHEREAS, the Lenders whose signatures appear below, constituting at least the Required Lenders, are willing to amend the Credit Agreement on the terms and subject to the conditions set forth herein;

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and in consideration of the premises contained herein, the parties hereto agree as follows:

1. Defined Terms. Capitalized terms used herein and not otherwise defined herein shall have the meanings ascribed to such terms in the Credit Agreement.

2. Amendment of Section 1.01 (Defined Terms). Section 1.01 of the Credit Agreement is hereby amended by adding the following defined terms in the proper alphabetical order:

"First Amendment" shall mean the First Amendment dated as of August 5, 2005 to this Agreement.

"First Amendment Effective Date" shall mean the date on which the First Amendment becomes effective.

3. Amendment of Section 3.23 (Energy Regulation). Section 3.23(c) of the Credit Agreement is hereby amended by adding after the first appearance of the word "Subsidiaries" the following clause: "(other than Subsidiaries regulated as steam utilities or chilled water providers)".

4. Amendment of Section 6.05 (Restricted Payments; Restrictive Agreements).

(i) Section 6.05(a) of the Credit Agreement is hereby amended by deleting the words "and (x)" in the first parenthetical in clause (C) of such Section and substituting therefor ", (x) and (xii)".

(ii) Section 6.05(b) of the Credit Agreement is hereby amended by (a) deleting (i) the word "and" at the end of clause (x) and (ii) the period at the end of clause (xi) of such Section and (b) adding the following clause at the end of paragraph (b) of such Section:

> "and (xii) the repurchase or redemption from and after the First Amendment Effective Date of Senior Notes in an aggregate principal amount (excluding prepayment or redemption premiums and accrued interest) not to exceed $228,750,000 with the proceeds of the issuance or sale of Equity Interests of the Company (other than Disqualified Stock) (it being understood, for the avoidance of doubt, that the proviso in Section 6.05(b)(ii) shall not apply to the net cash proceeds of the issuance or sale of Equity Interests described in this clause (xii))."

5. Representations and Warranties. In order to induce the other parties hereto to enter into this First Amendment, each of the Borrowers represents and warrants to each other party hereto that, as of the First Amendment Effective Date (as defined below):

(a) this First Amendment has been duly authorized, executed and delivered by each of the Borrowers and this First Amendment and the Credit Agreement, as amended hereby, constitutes each of the Borrower's legal, valid and binding obligation, enforceable against it in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting creditors' rights generally and subject to general principles of equity, regardless of whether considered in a proceeding in equity or at law;

(b) the representations and warranties set forth in each Loan Documents are, after giving effect to this First Amendment, true and correct in all material respects on and as of the First Amendment Effective Date with the same effect as though made on and as of the First Amendment Effective Date, except to the extent such representations and warranties relate to an earlier date, in which case such representations and warranties shall be true and correct in all material respects on and as of such earlier date, provided that the references to the Credit Agreement in such representations and warranties shall be deemed to refer to the Credit Agreement as amended pursuant to this First Amendment; and

(c) no Event of Default or Default has occurred and is continuing.

6. Conditions to Effectiveness of this First Amendment. This First Amendment shall become effective on the date (the "First Amendment Effective Date") on which:

(a) The Administrative Agent shall have received duly executed and delivered counterparts of this First Amendment that, when taken together, bear the signatures of each of the Borrowers and the Required Lenders.

(b) The Company shall have paid to the Administrative Agent all outstanding fees, costs and expenses owing to the Administrative Agent as of such date.

7. Continuing Effect; No Other Amendments. Except as expressly set forth in this First Amendment, all of the terms and provisions of the Credit Agreement are and shall remain in full force and effect and the Borrowers shall continue to be bound by all of such terms and provisions. The amendments provided for herein are limited to the specific provisions of the Credit Agreement specified herein and shall not constitute an amendment of, or an indication of the Administrative Agent's or the Lenders' willingness to amend or waive, any other provisions of the Credit Agreement or the same provisions for any other date or purpose. This First Amendment shall constitute a Loan Document.

8. Expenses; Indemnification. The Borrowers jointly and severally agree to pay and reimburse the Administrative Agent for all its reasonable out-of-pocket costs and expenses incurred in connection with the preparation and execution and delivery of this First Amendment, and any other documents prepared in connection herewith, and the transactions contemplated hereby, including, without limitation, reasonable fees, disbursements and other charges of counsel to the Administrative Agent and the customary charges of IntraLinks, Syndrak or any other third-party internet workspace utilized in connection with this First Amendment. Without limiting the foregoing, the Borrowers also hereby acknowledge that the provisions of Section 9.05 of the Credit Agreement (including, without limitation, the indemnification provisions of clause (b) thereof) shall apply in connection with this First Amendment.

9. Counterparts. This First Amendment may be executed by one or more of the parties to this First Amendment on any number of separate counterparts and all of said counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of an executed signature page of this First Amendment by facsimile transmission shall be effective as delivery of a manually executed counterpart hereof. A set of the copies of this First Amendment signed by all the parties shall be lodged with the Company and the Administrative Agent. The execution and delivery of this First Amendment by the Borrowers, the Lenders party hereto and the Administrative Agent shall be binding upon the Loan Parties, the Lenders, the Agents and all future holders of the Loans.

10. Effect of Amendment. On the First Amendment Effective Date, the Credit Agreement shall be amended as provided herein. The parties hereto acknowledge and agree that (a) this First Amendment and any other Loan Documents executed and delivered in connection herewith do not constitute a novation, or termination of the "Secured Obligations" (as defined in the Credit Agreement) under the Credit Agreement as in effect prior to the First Amendment Effective Date; (b) such "Secured Obligations" are in all respects continuing (as amended hereby) with only the terms thereof being modified to the extent provided in this First Amendment; and (c) the Liens and security interests as granted under the Security Documents securing payment of such "Secured Obligations" are in all respects continuing and in full force and effect and secure the payment of the "Secured Obligations".

11. GOVERNING LAW. THIS FIRST AMENDMENT AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES UNDER THIS FIRST AMENDMENT SHALL BE

GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.

[Signature Pages Follow]

IN WITNESS WHEREOF, the parties hereto have caused this First Amendment to be executed and delivered by their respective duly authorized officers as of the date first above written.

NRG ENERGY, INC.

By: /s/ GEORGE P. SCHAEFER
Name: George P. Schaefer
Title: VP and Treasurer

NRG POWER MARKETING INC.

By: GEORGE P. SCHAEFER
Name: George P. Schaefer
Title: VP and Treasurer

CREDIT SUISSE, CAYMAN ISLANDS BRANCH
(formerly known as Credit Suisse First Boston,
acting through its Cayman Islands Branch),
as Administrative Agent,

By: /s/ JAMES MORAN
Name: James Moran
Title: Managing Director

By: /s/ GREGORY S. RICHARDS
Name: Gregory S. Richards
Title: Associate

SIGNATURE PAGE TO FIRST AMENDMENT DATED AS OF AUGUST 5, 2005, TO
THE NRG ENERGY, INC. AND NRG POWER MARKETING INC.
AMENDED AND RESTATED CREDIT AGREEMENT
DATED AS OF DECEMBER 24, 2004

To Approve the First Amendment:

Name of Institution:

By: ______________________________

Name:
Title:

EXHIBIT 31.1

CERTIFICATION

I, David 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 our 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 our 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 our 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 our 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 CRANE

David Crane
Chief Executive Officer
(Principal Executive Officer)

Date: August 9, 2005

EXHIBIT 31.2

CERTIFICATION

I, Robert C. Flexon, 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 our 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 our 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 our 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 our 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/ ROBERT C. FLEXON

Robert C. Flexon
Chief Financial Officer
(Principal Financial Officer)

Date: August 9, 2005

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 our 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 our 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 our 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 our 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
Controller
(Principal Accounting Officer)

Date: August 9, 2005

EXHIBIT 32

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. (the Company) on Form 10-Q for the quarter ended June 30, 2005, as filed with the Securities and Exchange Commission on the date hereof (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 9, 2005

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

/s/ ROBERT C. FLEXON
Robert C. Flexon,
Chief Financial Officer
(Principal Financial Officer)

/s/ JAMES J. INGOLDSBY
James J. Ingoldsby,
Controller
(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.