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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: September 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 is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☑

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

Yes ☑ No ☐

As of November 3, 2005, there were 80,701,198 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 Securities 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:

- Risks and uncertainties related to the capital markets generally, including increases in interest rates and the availability of financing for our proposed acquisition of Texas Genco LLC as described in this Quarterly Report under the caption Note 1, *General — Recent Developments — Texas Genco Acquisition*, to Condensed Consolidated Financial Statements as well as our operating requirements;
- Our indebtedness and the additional indebtedness that we will incur in connection with the proposed acquisition;
- The ability to successfully complete the acquisition of Texas Genco LLC, regulatory or other limitations that may be imposed as a result of the acquisition, and the success of the business following the acquisition;
- General economic conditions, changes in the wholesale power markets and fluctuations in the cost of fuel or other raw materials;
- 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 realize our significant deferred tax assets, including loss carry forwards;
- The effectiveness of our risk management policies and procedures and the ability of our counterparties to satisfy their financial commitments;
- Counterparties’ collateral demands and other factors affecting our liquidity position and financial condition;
- Our ability to operate our businesses efficiently, manage capital expenditures and costs (including general and administrative expenses) tightly and generate earnings and cash flow from our asset-based businesses in relation to our debt and other obligations;
- 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.

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.

NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30, 2005	September 30, 2004	September 30, 2005	September 30, 2004
	(In thousands, except for per share amounts)			
Operating Revenues				
Revenues from majority-owned operations	$ 765,316	$ 604,632	$ 1,942,828	$ 1,770,669
Operating Costs and Expenses				
Cost of majority-owned operations	668,373	379,855	1,555,737	1,112,479
Depreciation and amortization	48,802	51,060	144,317	158,603
General, administrative and development	47,185	54,031	149,641	135,673
Other charges				
Corporate relocation charges	1,740	5,713	5,651	12,474
Reorganization items	—	(5,245)	—	(1,656)
Impairment charges	6,000	40,507	6,223	42,183
Total operating costs and expenses	772,100	525,921	1,861,569	1,459,756
Operating Income/(Loss)	(6,784)	78,711	81,259	310,913
Other Income (Expense)				
Minority interest in earnings of consolidated subsidiaries	(13)	(18)	(36)	(18)
Equity in earnings of unconsolidated affiliates	29,077	53,373	82,501	117,187
Write downs and gains/(losses) on sales of equity method investments	4,333	(13,524)	15,894	(14,057)
Other income, net	9,956	5,478	43,208	17,145
Refinancing expense	(19,012)	—	(44,036)	(30,417)
Interest expense	(45,791)	(66,110)	(150,598)	(193,463)
Total other expense	(21,450)	(20,801)	(53,067)	(103,623)
Income/(Loss) From Continuing Operations Before Income Taxes	(28,234)	57,910	28,192	207,290
Income Tax Expense	8,511	14,559	21,201	65,136
Income/(Loss) From Continuing Operations	(36,745)	43,351	6,991	142,154
Income from discontinued operations, net of income taxes	9,864	10,870	12,612	25,326
Net Income/(Loss)	(26,881)	54,221	19,603	167,480
Preference stock dividends	4,200	—	12,272	—
Income/(Loss) Available for Common Stockholders	$ (31,081)	$ 54,221	$ 7,331	$ 167,480
Weighted Average Number of Common Shares Outstanding — Basic	83,529	100,101	85,860	100,066
Income/(Loss) From Continuing Operations per Weighted Average Common Share — Basic	$ (0.51)	$ 0.43	$ (0.08)	$ 1.42
Income From Discontinued Operations per Weighted Average Common Share — Basic	0.12	0.11	0.15	0.25
Income/(Loss) Available for Common Stockholders per Weighted Average Common Share — Basic	$ (0.39)	$ 0.54	$ 0.07	$ 1.67
Weighted Average Number of Common Shares Outstanding — Diluted	83,529	100,616	85,860	100,328
Income/(Loss) From Continuing Operations per Weighted Average Common Share — Diluted	$ (0.51)	$ 0.43	$ (0.08)	$ 1.42
Income From Discontinued Operations per Weighted Average Common Share — Diluted	0.12	0.11	0.15	0.25
Income/(Loss) Available for Common Stockholders per Weighted Average Common Share — Diluted	$ (0.39)	$ 0.54	$ 0.07	$ 1.67

See notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2005 (unaudited)	December 31, 2004
	(In thousands)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 504,336	$ 1,103,678
Restricted cash	91,508	109,633
Accounts receivable, less allowance for doubtful accounts of $3,280 and $6,591	308,839	269,611
Current portion of notes receivable	24,934	85,447
Income taxes receivable	31,237	37,484
Inventory	203,547	248,010
Derivative instruments valuation	451,545	79,759
Prepayments and other current assets	129,289	135,520
Collateral on deposit in support of energy risk management activities	631,436	33,325
Deferred income taxes	44,832	—
Current assets — discontinued operations	—	15,821
Total current assets	2,421,503	2,118,288
Property, plant and equipment, net of accumulated depreciation of $346,886 and $205,928	3,226,714	3,329,000
Other Assets		
Equity investments in affiliates	651,412	734,950
Notes receivable, less current portion, less reserve for uncollectible notes of $0 and $8,196	712,020	804,450
Intangible assets, net	268,897	294,350
Derivative instruments valuation	31,973	41,787
Funded letter of credit	350,000	350,000
Other non-current assets	132,848	111,574
Non-current assets — discontinued operations	—	45,884
Total other assets	2,147,150	2,382,995
Total Assets	$ 7,795,367	$ 7,830,283
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 176,024	$ 511,258
Accounts payable	152,968	171,722
Derivative instruments valuation	973,143	16,772
Deferred income taxes	—	334
Other bankruptcy settlement	175,945	175,576
Accrued expenses and other current liabilities	389,396	209,367
Current liabilities — discontinued operations	—	2,912
Total current liabilities	1,867,476	1,087,941
Other Liabilities		
Long-term debt and capital leases	2,866,374	3,212,596
Deferred income taxes	103,199	134,580
Derivative instruments valuation	198,554	148,445
Out-of-market contracts	302,639	318,664
Other non-current liabilities	190,897	187,438
Non-current liabilities — discontinued operations	—	47,759
Total non-current liabilities	3,661,663	4,049,482
Total Liabilities	5,529,139	5,137,423
Minority Interest	869	696
3.625% Convertible Perpetual Preferred Stock; $.01 par value; 10,000,000 shares authorized, 250,000 shares issued and outstanding (at liquidation value, net of issuance costs)	246,191	—
Commitments and Contingencies		
Stockholders' Equity		
4% Convertible Perpetual Preferred Stock; $.01 par value; 10,000,000 shares authorized, 420,000 issued and outstanding (at liquidation value, net of issuance costs)	406,155	406,359
Common Stock; $.01 par value; 500,000,000 shares authorized; 80,701,198 and 87,041,935 outstanding	1,000	1,000
Additional paid-in capital	2,427,322	2,417,021
Retained earnings	203,973	196,642
Less treasury stock, at cost — 19,346,788 and 13,000,000 shares	(663,529)	(405,312)
Accumulated other comprehensive income/(loss)	(355,753)	76,454
Total stockholders' equity	2,019,168	2,692,164
Total Liabilities and Stockholders' Equity	$ 7,795,367	$ 7,830,283

See notes to condensed consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

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

	Serial Preferred		Common						
(In thousands)	Stock	Shares	Stock	Shares	Additional Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income/(loss)	Total Stockholders' Equity
Balances at June 30, 2004	—	—	$ 1,000	100,007	$2,410,751	$124,284	$ —	$ 43	$ 2,536,078
Net income						54,221			54,221
Foreign currency translation adjustments								22,434	22,434
Deferred unrealized loss on derivatives, net								(18,793)	(18,793)
Comprehensive income									57,862
Equity compensation	—	—	—	1	3,211	—	—	—	$ 3,211
Balances at September 30, 2004	—	—	$ 1,000	100,008	$2,413,962	$178,505	$ —	$ 3,684	$ 2,597,151
Balances at June 30, 2005	406,155	420	1,000	87,045	2,423,636	235,054	(405,312)	(59,882)	2,600,651
Net loss						(26,881)			(26,881)
Foreign currency translation adjustments								(572)	(572)
Deferred unrealized loss on derivatives								(295,604)	(295,604)
Unrealized gain on available for sale securities by affiliate								305	305
Comprehensive loss									(322,752)
4% Preferred Stock dividend						(4,200)			(4,200)
Accelerated Share Repurchase				(6,347)			(258,217)		(258,217)
Equity compensation	—	—	—	3	3,686	—	—	—	3,686
Balances at September 30, 2005	$406,155	420	$ 1,000	80,701	$2,427,322	$203,973	$(663,529)	$ (355,753)	$ 2,019,168
Balances at December 31, 2003	—	—	1,000	100,000	2,403,429	11,025	$ —	21,802	2,437,256
Net income						167,480			167,480
Foreign currency translation adjustments								(13,499)	(13,499)
Deferred unrealized gain on derivatives, net								(4,619)	(4,619)
Comprehensive income									149,362
Equity compensation	—	—	—	8	10,533	—	—	—	10,533
Balances at September 30, 2004	—	—	$ 1,000	100,008	$2,413,962	$178,505	$ —	$ 3,684	$ 2,597,151
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						19,603			19,603
Foreign currency translation adjustments								(50,336)	(50,336)
Deferred unrealized loss on derivatives								(382,176)	(382,176)
Unrealized gain on available for sale securities by affiliate								305	305
Comprehensive loss									(412,604)
Issue costs	(204)								(204)
4% Preferred Stock dividend						(12,272)			(12,272)
Accelerated Share Repurchase				(6,347)			(258,217)		(258,217)
Equity compensation	—	—	—	6	10,301	—	—	—	10,301

Balances at September 30, 2005	$406,155	420	$ 1,000	80,701	$2,427,322	$203,973	$(663,529)	$ (355,753)	$ 2,019,168

See notes to condensed consolidated financial statements.

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NRG ENERGY, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
	(In thousands)	
Cash Flows from Operating Activities		
Net income	$ 19,603	$ 167,480
Adjustments to reconcile net income to net cash provided/(used) by operating activities		
Distributions in excess/(less) than equity in earnings of unconsolidated affiliates	1,100	(13,703)
Depreciation and amortization	145,076	164,872
Reserve for note and interest receivable	(98)	4,572
Amortization of debt issuance costs and debt discount	7,651	22,813
Write-off of deferred financing costs/(debt premium)	(7,701)	15,312
Deferred income taxes	(53,605)	67,655
Minority interest	899	1,961
Unrealized (gains)/losses on derivatives	252,256	(33,232)
Asset impairment	6,223	42,183
Write downs and (gains)/losses on sales of equity method investments	(15,894)	14,057
Gain on TermoRio settlement	(13,532)	—
Gain on sale of discontinued operations	(10,735)	(29,924)
Amortization of power contracts and emission credits	16,118	42,822
Amortization of unearned equity compensation	8,404	10,533
Collateral deposit payments in support of energy risk management activities	(598,111)	(28,783)
Cash provided by changes in other working capital, net of disposition affects	128,544	146,803
Net Cash (Used)/Provided by Operating Activities	(113,802)	595,421
Cash Flows from Investing Activities		
Proceeds on sale of equity method investments	69,575	29,693
Proceeds on sale of discontinued operations	35,658	246,498
Return of capital from (investments in) equity method investments and projects	1,333	(672)
Decrease in notes receivable, net	100,354	36,609
Capital expenditures	(45,518)	(78,293)
Increase/(decrease) in restricted cash and trust funds, net	17,915	(23,029)
Net Cash Provided by Investing Activities	179,317	210,806
Cash Flows from Financing Activities		
Payment of dividends to preferred stockholders	(12,272)	—
Repayment of minority interest obligations	(3,581)	—
Accelerated share repurchase payment, net	(250,717)	—
Issuance of 3.625% Preferred Stock, net	246,126	—
Deferred debt issuance costs	(1,539)	(8,497)
Issuance expense of 4% Preferred Stock	(204)	—
Net borrowings under revolving credit facility	80,000	—
Proceeds from issuance of long-term debt, net	249,139	531,207
Principal payments on short and long-term debt	(979,379)	(750,343)
Net Cash Used by Financing Activities	(672,427)	(227,633)
Change in Cash from Discontinued Operations	8,051	(26,486)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(481)	(2,507)
Net Increase (Decrease) in Cash and Cash Equivalents	(599,342)	549,601
Cash and Cash Equivalents at Beginning of Period	1,103,678	549,181
Cash and Cash Equivalents at End of Period	$ 504,336	$ 1,098,782

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", "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.

Recent Developments – Texas Genco Acquisition

On September 30, 2005, we entered into an Acquisition Agreement with Texas Genco LLC, a Delaware limited liability company, or Texas Genco, and each of the direct and indirect owners of Texas Genco, referred to as the Sellers. Pursuant to the Acquisition Agreement, NRG agreed to purchase all of the outstanding equity interests in Texas Genco for a total purchase price of approximately $5.825 billion, which includes the assumption by the Company of approximately $2.5 billion of indebtedness. The purchase price is subject to adjustment, and includes an equity component valued at $1.8 billion based on a price per share of $40.50 of NRG's common stock. As a result of the Acquisition, Texas Genco will become a wholly owned subsidiary of NRG and will nearly double NRG's U.S. generation portfolio from 12,981 Megawatts to 23,920 Megawatts.

Pending closing of the Acquisition, Texas Genco and NRG are obligated to conduct their businesses in the ordinary course of business, to preserve their business, assets, properties and relationships, and to refrain from certain activities without prior written consent of the other party, such consent not to be unreasonably withheld or delayed. NRG is devoting substantial resources to satisfying remaining conditions precedent, arranging financing, closing the Acquisition and planning the integration of the combined companies post-closing.

Texas Genco owns and operates 11 fossil-fuel fired electric power generation facilities in various locations in Texas, as well as a 44% undivided interest in the South Texas Project nuclear electric power generation facility, or STP. Texas Genco sells wholesale electric generation capacity, energy and ancillary services in the Electric Reliability Council of Texas market, or ERCOT.

Of the approximately $5.825 billion payable to the Sellers upon consummation of the Acquisition, NRG will pay $4.025 billion in cash, subject to adjustment, and issue a minimum of 35,406,320 shares of NRG's common stock. At NRG's election, the remaining consideration may be comprised of an additional 9,038,125 shares of common stock, or at NRG's election, the equivalent in the form of any combination of common stock, additional cash and shares of a new series of the NRG's Cumulative Redeemable Preferred Stock, referred to as the Cumulative Preferred Stock. If issued, the liquidation preference of the Cumulative Preferred Stock will be determined with reference to the average price of NRG's common stock over a twenty trading day period prior to the closing of the Acquisition. If NRG elects to pay all or a portion of the remaining purchase price in cash, the amount payable in cash would be calculated in the same manner. The purchase price payable by NRG is subject to adjustment based on the following items as of the closing date – the level of Texas Genco's working capital, the amount of Texas Genco's indebtedness and the amount of Texas Genco's cash and cash equivalents.

NRG expects to finance the Acquisition through a combination of a new senior secured credit facility, an unsecured high yield notes offering and the sale of common and preferred equity securities in the public markets. NRG has received a commitment letter from Morgan Stanley Senior Funding, Inc., or Morgan Stanley, and Citigroup Global Markets, Inc., or Citigroup, to provide the Company with up to $4.8 billion in senior secured debt financing, including up to $3.2 billion under a senior first priority term loan facility, up to $600 million under a senior first priority secured revolving credit facility and up to $1 billion under a senior first priority secured synthetic letter of credit facility. The commitment letter further provides for up to $5.1 billion in bridge financing to fund all necessary amounts not provided for under the senior secured debt financing. NRG does not intend to draw down on the bridge financing unless the contemplated high-yield debt financing and preferred and common equity financings are for some reason unavailable at the time of the closing. The commitment letter is subject to customary conditions to consummation, including the absence of any event or circumstance that would have a material adverse effect on the business, assets, properties, liabilities, condition (financial or otherwise) or results of operations, taken as a whole, of Texas Genco, or Texas Genco and NRG combined, since June 30, 2005.

Each of the parties' obligation to consummate the Acquisition is subject to certain customary conditions, including (i) the absence of any event or circumstance that would have a material adverse effect on the other party's business, assets, properties, liabilities, condition (financial or otherwise) or results of operations, taken as a whole, since June 30, 2005 and (ii) the receipt of required regulatory approvals, including the expiration of the required waiting period under the Hart Scott Rodino Antitrust Improvements Act, and the approval of the Nuclear Regulatory Commission and the Federal Energy Regulatory Commission. NRG could be obligated to close under the Acquisition Agreement, but Morgan Stanley and Citigroup would not be required to fund under the commitment letter, if a material adverse effect occurred with respect to Texas Genco and NRG combined, but not with respect to only Texas Genco. Subject to the foregoing conditions, the Acquisition is expected to be consummated in the first quarter of 2006.

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 September 30, 2005, the results of our operations and stockholders' equity for the nine months and three months ended September 30, 2005 and 2004, and our cash flows for the nine months ended September 30, 2005 and 2004. Certain prior-period 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/(loss) during any period. Actual results could differ from those estimates.

Emission Allowances and Fuel Commodities

During the third quarter of 2005, NRG began selling its excess SO_2 emission allowances. NRG records the sale of these allowances in Operating Revenues. The cost basis of these allowances, established upon the adoption of Fresh Start, is recorded in Operating Costs and Expenses. Beginning in 2006, NRG may actively manage its SO_2 emission allowances as well as fuels. NRG will account for asset optimization activity related to emission allowances and other fuel commodities under EITF Issue No. 02-3, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities". As such, revenues and costs for these activities would be reflected on a net basis in the consolidated statement of operations.

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) *Share Based Payment*, or SFAS 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 September 15, 2005. We will adopt SFAS No.123(R) and SAB 107 on January 1, 2006.

On March 17, 2005, the Emerging Issues Task Force, or EITF, issued EITF Issue No. 04-6, or EITF 04-6. EITF 04-6 provides that costs incurred to remove overburden and waste material to access coal seams, or stripping costs, 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 €156.7 million, approximately $188.4 million, representing the stripping costs incurred during production as of September 30, 2005. The adoption of EITF 04-6 will not have a material impact on our consolidated results of operations, but will have a material impact on our consolidated financial position. Following adoption, our investment in MIBRAG will be reduced by 50% of the above mentioned asset, approximately $94.4 million, with an offsetting charge to retained earnings.

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.

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.

On June 29, 2005, the EITF issued EITF Issue No. 04-5, or EITF 04-5. EITF 04-5 provides a framework for addressing when a general partner controls a limited partnership when the limited partners have certain rights. EITF 04-5's scope excludes a number of investment types, including limited partnerships entities that are not variable interest entities under FIN 46(R), and investments accounted for under the pro rata method of consolidation. The guidance in EITF 04-5 is effective immediately to general partners of all new limited partnerships formed and for existing limited partnerships for which the partnership agreements are modified. For general partners in all other limited partnerships, the guidance in EITF 04-5 is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005. Currently, this guidance will 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.

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 nine months ended September 30, 2005, discontinued operations consisted of activity related to Northbrook New York LLC, Northbrook Energy LLC and NRG McClain. For the three and nine months ended September 30, 2004, discontinued operations included our Northbrook New York LLC, Northbrook Energy LLC, 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, Northbrook New York LLC, Northbrook Energy LLC are included in the Other North America 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		Nine Months Ended	
	September 30, 2005	September 30, 2004	September 30, 2005	September 30, 2004
	(In thousands)			
Operating revenues	938	8,274	9,135	118,310
Pre-tax income from operations of discontinued operations	30	83	2,972	3,653
Income on discontinued operations, net of income taxes	9,864	10,870	12,612	25,326

Northbrook New York LLC and Northbrook Energy LLC – On August 11, 2005, we completed the sale of Northbrook New York LLC and Northbrook Energy LLC. In exchange for the sale, we received net cash proceeds of $36 million and paid off Northbrook New York LLC's third party debt of $17.1 million. We recognized a net pre-tax gain of $12.3 million in the third quarter of 2005.

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		Nine Months Ended	
	September 30, 2005	September 30, 2004	September 30, 2005	September 30, 2004
	(In thousands)			
Kendall	$ 4,333	$ —	$ 4,333	$ —
Enfield	—	—	11,561	—
Commonwealth Atlantic Limited Partnership	—	(3,686)	—	(3,686)
James River Power LLC	—	(6,008)	—	(6,008)
NEO Corporation-2004	—	(3,830)	—	(3,830)
Calpine Cogeneration	—	—	—	735
Loy Yang	—	—	—	(1,268)
Total write downs and gains/(losses) on sales of equity method investments	$ 4,333	$ (13,524)	$ 15,894	$ (14,057)

Kendall — In December 2004, we sold our interest in Kendall to LS Power Associates, L.P., or LS Power. Under the terms of the December 2004 agreement, we retained the right to acquire a 40% interest in the plant within a 10-year period for a nominal amount, or the Call Option. Therefore, the transaction was treated as a partial sale for accounting purposes. On August 8, 2005, we executed an agreement with LS Power to sell the Call Option for $5 million. A pre-tax gain of $4.3 million was recognized in the third quarter of 2005.

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.

Note 5 — Other Charges

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 nine months ended September 30, 2005 and 2004, we recorded $5.7 million and $12.5 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 $0.3 million to finalize certain housing relocations in the fourth quarter of 2005 of SFAS No. 146-classified expenses in connection with corporate relocation charges for a total of $22.2 million.

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

	Year Ended December 31, 2004	Nine Months Ended September 30, 2005	Yet to be Incurred	Expected Total Charges
		(In thousands)		
Employee related transition costs	$ 8,595	$ 1,710	$ 348	$ 10,653
Severance and termination benefits	6,505	579	—	7,084
Lease termination costs	1,067	3,362	—	4,429
Total corporate relocation charges	$ 16,167	$ 5,651	$ 348	$ 22,166

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 September 30, 2005
		(In thousands)		
Employee related transition costs	$ (1,425)	$ 1,710	$ (645)	$ (360)
Severance and termination benefits	4,939	915	(5,854)	—
Lease termination costs	796	3,362	(1,225)	2,933
Total	$ 4,310	$ 5,987	$ (7,724)	$ 2,573

As of September 30, 2005, the restructuring liability was $2.6 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 nine months ended September 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. Lease termination costs require that cash payments be made through the fourth quarter of 2006.

Impairment Charges

In accordance with the guidelines of SFAS No. 144, certain events led to the review of the recoverability of some of our long-lived assets. As a result of this review, we recorded $6.0 million and $6.2 million in impairment charges for the three and nine months ended September 30, 2005, respectively, and $40.5 million and $42.2 million for the three and nine months ended September 30, 2004, respectively, which included the following:

Project Name	Project Status	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004	Fair Value Basis
		(in thousands)				
Berrians I Gas Turbine Power LLC	Non-operating asset	$ 6,000	$ —	$ 6,000	$ —	Estimated market price
New Roads Holding LLC (turbine)	Non-operating asset- abandoned	—	740	—	2,416	Projected cash flows
Devon Power LLC	Operating at a loss	—	247	—	247	Projected cash flows
Kendall Energy LLC	Held for sale – Non-operating asset	—	24,520	—	24,520	Projected cash flows
Meriden (turbine only)	Indicative market valuation	—	15,000	—	15,000	Projected cash flows
Other		—	—	223	—	
Total impairment charges		$ 6,000	$ 40,507	$ 6,223	$ 42,183	

Berrians I Gas Turbine Power LLC, or Berrians Project – Until the third quarter of 2005, NRG had been evaluating the use of an unused turbine for the Berrians Project located within our Other North America segment. We have concluded that this is most likely not feasible. As such, we have increased our efforts to sell the turbine to a third party and intend to hold an auction in the fourth quarter. As a result, we impaired the turbine based on the estimated current market price which was significantly lower than book value.

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 nine months ended September 30, 2005, we recorded equity earnings of $6.7 million and $15.2 million, respectively, for WCP after adjustments for the reversal of $2.7 million and $9.0 million, respectively, of project level depreciation expense. For the three and nine months ended September 30, 2004, we recorded equity earnings of $17.2 million and $45.1 million, respectively, after adjustments for the reversal of $3.7 million and $11.3 million, respectively, of project level depreciation expense, offset by a decrease in earnings related to $28.1 million and $89.7 million, respectively, of amortization of the intangible asset for the California Department of Water Resources contract, referred to as the 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 September 30 2005	Three Months Ended September 30 2004	Nine Months Ended September 30 2005	Nine Months Ended September 30 2004
Operating revenues	$ 61	$ 183	$ 219	$ 535
Operating income	6	82	8	246
Income before tax	8	83	12	247

Note 7 — Accounting for Derivative Instruments and Hedging Activities

SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*", or 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 Other Comprehensive Income, or 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 OCI.

Accumulated Other Comprehensive Income

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

	Energy Commodities	Interest Rate	Foreign Currency	Total
		(In thousands)		
Accumulated OCI balance at June 30, 2005	$ (76,706)	$ (2,397)	$ —	$ (79,103)
Unwound from OCI during the period:				
— Due to unwinding of previously deferred amounts	54,676	(2,030)	—	52,646
Mark-to-market of hedge contracts	(358,741)	10,491	—	(348,250)
Accumulated OCI balance at September 30, 2005	$ (380,771)	$ 6,064	$ —	$(374,707)
Gains/(Losses) expected to unwind from OCI during the next 12 months	(345,527)	3,345	—	(342,182)

The following table summarizes the effects of SFAS No. 133 on our OCI balance attributable to hedged derivatives for the nine months ended September 30, 2005:

	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	52,957	(1,167)	—	51,790
Mark-to-market of hedge contracts	(439,210)	5,244	—	(433,966)
Accumulated OCI balance at September 30, 2005	$ (380,771)	$ 6,064	$ —	$(374,707)
Gains/(Losses) expected to unwind from OCI during the next 12 months	(345,527)	3,345	—	(342,182)

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

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Accumulated OCI balance at June 30, 2004	$ (8,942)	$ 22,593	$ —	$ 13,651
Unwound from OCI during period:				
— Due to unwinding of previously deferred amounts	972	(3,307)	—	(2,335)
Mark-to-market of hedge contracts, net of tax	(1,920)	(14,538)	—	(16,458)
Accumulated OCI balance at September 30, 2004	$ (9,890)	$ 4,748	$ —	$ (5,142)

The following table summarizes the effects of SFAS No. 133 on our OCI balance attributable to hedged derivatives for the nine months ended September 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	9,756	3,751	170	13,677
Mark-to-market of hedge contracts, net of tax	(17,693)	(603)	—	(18,296)
Accumulated OCI balance at September 30, 2004	$ (9,890)	$ 4,748	$ —	$ (5,142)

Losses of $52.6 million and of $51.8 million were reclassified from OCI to current period earnings during the three and nine months ended September 30, 2005, respectively, 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 nine months ended

September 30, 2005 we recorded losses in OCI of approximately $348.3 million and losses of $433.9 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 September 30, 2005 was an unrecognized loss of approximately $374.7 million. We expect $342.2 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 derivatives that do not qualify for hedge accounting treatment on our statement of operations for the three months ended September 30, 2005:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Revenue from majority-owned subsidiaries	$ (164,255)	$ —	$ —	$(164,255)
Cost of operations	6,457	—	—	6,457
Total statement of operations impact before tax	$ (170,712)	$ —	$ —	$(170,712)

The following tables summarize the pre-tax effects of derivatives do not qualify for hedge accounting treatment on our statement of operations for the nine months ended September 30, 2005:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Revenue from majority-owned subsidiaries	$ (245,864)	$ —	$ —	$(245,864)
Equity in earnings of unconsolidated subsidiaries	11,868	—	—	11,868
Cost of operations	5,073	—	—	5,073
Total statement of operations impact before tax	$ (239,069)	$ —	$ —	$(239,069)

The following tables summarize the pre-tax effects of derivatives do not qualify for hedge accounting treatment on our statement of operations for the three months ended September 30, 2004:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Revenue from majority-owned subsidiaries	$ (3,809)	$ —	$ —	$ (3,809)
Equity in earnings of unconsolidated subsidiaries	14,095	(215)	—	13,880
Cost of operations	(2,097)	—	—	(2,097)
Total statement of operations impact before tax	$ 12,383	$ (215)	$ —	$ 12,168

The following tables summarize the pre-tax effects of derivatives that do not qualify for hedge accounting treatment on our statement of operations for the nine months ended September 30, 2004:

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Revenue from majority-owned subsidiaries	$ 3,659	$ —	$ —	$ 3,659
Equity in earnings of unconsolidated subsidiaries	22,601	414	—	23,015
Cost of operations	(465)	—	—	(465)
Other income	—	411	—	411
Total statement of operations impact before tax	$ 26,725	$ 825	$ —	$ 27,550

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.
- 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 nine months ended September 30, 2005 our pre-tax earnings were affected by an unrealized loss of $0.4 million due to the ineffectiveness associated with financial forward contracted electric sales.

During the three and nine months ended September 30, 2005, our pre-tax earnings were affected by an unrealized loss of $170.7 million and $250.9 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 effect of unrealized gains and losses recorded by equity investees.

During the three and nine months ended September 30, 2004, our pre-tax earnings were affected by an unrealized loss of $1.7 million and $4.1 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 nine months ended September 30, 2005, we reclassified losses of $54.7 million and $53.0 million, respectively, from OCI to current period earnings and expect to reclassify approximately $345.5 million of deferred losses to earnings during the next twelve months on energy related derivative instruments accounted for as hedges.

During the three and nine months ended September 30, 2004, we reclassified losses of $1.0 million and $9.8 million, respectively, from OCI to current period earnings.

At September 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 nine months ended September 30, 2005 and 2004 was immaterial to our financial results.

During the three and nine months ended September 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 nine months ended September 30, 2005, we reclassified gains of $2.0 million and $1.2 million, respectively, from OCI to current period earnings and expect to reclassify approximately $3.3 million of deferred gains to earnings during the next twelve months associated with interest rate swaps accounted for as hedges.

During the three and nine months ended September 30, 2004, we reclassified gains of $3.3 million and losses of $3.8 million, respectively, from OCI to current period earnings.

At September 30, 2005, we had interest rate derivative instruments extending through September 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 September 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 8% Second Priority Notes, or 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 July 28, 2005, we closed the registered exchange offer to exchange up to $1.35 billion aggregate principal amount of the Second Priority Notes, which were registered under the Securities Act of 1933, as amended, for all outstanding Second Priority Notes that were issued and sold by NRG in December 2003 and January 2004 in private placement offerings. $1,348,508,000 in aggregate principal amount or 99.89% of the outstanding Second Priority Notes were exchanged. On September 12, 2005, we redeemed $228.8 million in Second Priority Notes and paid $18.3 million for the early redemption premium on the redeemed notes which was recorded to refinancing expense. During the nine months ended September 30, 2005, we redeemed or repurchased $644.6 million of our Second Priority Notes, and paid $51.7 million in fees and market premiums.

As of September 30, 2005, we had $80.0 million drawn under our $150.0 million corporate revolving credit facility. As of November 3, 2005, this facility was 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 September 30, 2005. An interim arrangement to indemnify the Australia New Zealand Bank, or 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. On August 25, 2005, Flinders redrew AUD 60.5 million (US $46.1 million). As of September 30, 2005, AUD 246.3 million (US $187.9 million) was outstanding.

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 performance 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 reconciliation of basic earnings per common share to diluted earnings per common share is shown in the following table:

	Three Months Ended September 30 2005	Three Months Ended September 30 2004	Nine Months Ended September 30 2005	Nine Months Ended September 30 2004
	(In thousands, except per share data)			
Basic earnings per share				
Numerator:				
Income (loss) from continuing operations	$ (36,745)	$ 43,351	$ 6,991	$ 142,154
Preferred stock dividends	(5,459)	—	(13,859)	—
Net (loss) income available to common stockholders from continuing operations	(42,204)	43,351	(6,868)	142,154
Discontinued operations, net of tax	9,864	10,870	12,612	25,326
Net income (loss) available to common stockholders	$ (32,340)	$ 54,221	$ 5,744	$ 167,480
Denominator:				
Weighted average number of common shares outstanding	83,529	100,101	85,860	100,066
Basic earnings per share:				
Income (loss) from continuing operations	$ (0.51)	$ 0.43	$ (0.08)	$ 1.42
Discontinued operations, net of tax	0.12	0.11	0.15	0.25
Net income (loss)	$ (0.39)	$ 0.54	$ 0.07	$ 1.67
Diluted earnings per share				
Numerator:				
Net income (loss) available to common stockholders from continuing operations	$ (42,204)	$ 43,351	$ (6,868)	$ 142,154
Discontinued operations, net of tax	9,864	10,870	12,612	25,326
Net income (loss) available to common stockholders	$ (32,340)	$ 54,221	$ 5,744	$ 167,480
Denominator:				
Weighted average number of common shares outstanding	83,529	100,101	85,860	100,066
Incremental shares attributable to the issuance of nonvested restricted stock units (treasury stock method)	—	496	—	262
Incremental shares attributable to the issuance of nonvested nonqualifying stock options (treasury stock method)	—	19	—	—
Total dilutive shares	83,529	100,616	85,860	100,328
Diluted earnings per share:				
Income (loss) from continuing operations	$ (0.51)	$ 0.43	$ (0.08)	$ 1.42
Discontinued operations, net of tax	0.12	0.11	0.15	0.25
Net income (loss)	$ (0.39)	$ 0.54	$ 0.07	$ 1.67

For the three and nine months ended September 30, 2005, the outstanding 4% Convertible Perpetual Preferred Stock, or 4% Preferred Stock, 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 same periods, the 3.625% Convertible Perpetual Preferred Stock, or 3.625% Preferred Stock, were also anti-dilutive as the weighted average closing price of our common stock was below the conversion price.

As part of the Accelerated Share Repurchase Agreement with Credit Suisse First Boston Capital LLC, or CSFB, NRG will have a purchase price adjustment which is payable in cash or common stock. We expect to incur an adjustment and since we intend to pay this amount in cash, there should be no dilutive effect to earnings per share. See Note 16, *Accelerated Share Repurchase Plan* for additional information.

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 changed 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 and nine month period ended September 30, 2005, assuming the prior allocation criteria was still in effect.

	Three Months Ended September 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	$ 438,544	$ 174,586	$ 431	$ 10,224	$ 55,956	$ 41,353	$ 18,586	$ 42,315	$ (16,679)	$ 765,316
Depreciation and amortization	18,643	15,284	30	1,670	7,117	906	1,320	2,744	1,088	48,802
Equity in earnings of unconsolidated affiliates	—	—	6,987	6,588	6,012	9,482	8	—	—	29,077
Income/(loss) from continuing operations before income taxes	4,171	(8,352)	5,986	(1,028)	2,255	22,861	1,420	11,694	(67,241)	(28,234)
Net income/(loss) from continuing operations	4,157	(8,352)	5,941	(1,737)	2,296	17,255	996	10,167	(67,468)	(36,745)
Net income/(loss) from discontinued operations, net of tax	—	—	—	(871)	—	—	10,735	—	—	9,864
Net income/(loss)	4,157	(8,352)	5,941	(2,608)	2,296	17,255	11,731	10,167	(67,468)	(26,881)
Total assets	2,158,775	1,041,031	226,105	694,571	903,664	639,387	30,247	1,068,336	1,033,251	7,795,367

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

Net income/(loss) as reported	4,157	(8,352)	5,941	(2,608)	2,296	17,255	11,731	10,167	(67,468)	(26,881)
Increase/(decrease) in net income	4,137	2,699	(82)	(410)	1,223	778	312	1,059	(9,716)	—
Adjusted net income/(loss)	8,294	(5,653)	5,859	(3,018)	3,519	18,033	12,043	11,226	(77,184)	(26,881)

	Three Months Ended September 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	$321,097	$107,140	$ 3,413	$ 38,881	$47,406	$ 37,986	$ 16,839	$ 33,388	$ (1,518)	$604,632
Depreciation and amortization	18,190	15,658	197	5,005	5,179	732	1,301	2,717	2,081	51,060
Equity in earnings of unconsolidated affiliates	—	—	19,188	14,114	2,060	18,336	(325)	—	—	53,373
Income/(loss) from continuing operations before income taxes	87,821	14,407	18,180	(19,042)	2,256	26,666	(2,387)	7,450	(77,441)	57,910
Net income/(loss) from continuing operations	87,821	14,407	18,425	(19,426)	4,117	24,244	(359)	4,040	(89,918)	43,351
Net income from discontinued operations, net of tax	—	—	—	11,724	—	—	3,540	—	(4,394)	10,870
Net income/(loss)	87,821	14,407	18,425	(7,702)	4,117	24,244	3,181	4,040	(94,312)	54,221

	Nine Months Ended September 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	$1,086,680	$400,661	$ 581	$ 16,835	$161,879	$ 123,522	$ 53,929	$118,273	$ (19,532)	$1,942,828
Depreciation and amortization	55,834	45,511	425	5,014	19,829	2,560	3,954	8,223	2,967	144,317
Equity in earnings of unconsolidated affiliates	—	—	19,079	10,237	17,727	35,439	19	—	—	82,501
Income/(loss) from continuing operations before income taxes	75,911	(5,863)	15,179	(13,747)	18,778	91,350	5,494	19,783	(178,693)	28,192
Net income/(loss) from continuing operations	75,897	(5,863)	15,109	(15,611)	16,689	77,961	4,654	17,703	(179,548)	6,991
Net income from discontinued operations, net of tax	—	—	—	1,877	—	—	10,735	—	—	12,612
Net income/(loss)	75,897	(5,863)	15,109	(13,734)	16,689	77,961	15,389	17,703	(179,548)	19,603

If the Company continued using the previous year's allocation method for corporate general and administrative expenses, the effect to the net income of each segment for the nine months ended September 30, 2004 would be as follows:

Net income/(loss) as reported	75,897	(5,863)	15,109	(13,734)	16,689	77,961	15,389	17,703	(179,548)	19,603
Increase/(decrease) in net income	17,492	9,810	(356)	(1,147)	4,629	2,946	1,069	3,855	(38,298)	—
Adjusted net income/(loss)	93,389	3,947	14,753	(14,881)	21,318	80,907	16,458	21,558	(217,846)	19,603

	Nine Months Ended September 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	$926,666	$304,902	$ 1,020	$ 81,452	$146,428	$ 117,426	$ 49,219	$148,826	$ (5,270)	$1,770,669
Depreciation and amortization	54,101	47,192	602	18,915	17,190	2,069	3,979	8,570	5,985	158,603
Equity in earnings of unconsolidated affiliates	—	—	49,885	16,415	8,766	41,696	425	—	—	117,187
Income/(loss) from continuing operations before income taxes	231,479	42,278	42,780	(31,579)	10,378	67,283	2,773	60,513	(218,615)	207,290
Net income/(loss) from continuing operations	231,479	42,278	42,688	(32,682)	12,345	55,411	4,793	56,477	(270,635)	142,154
Net income from discontinued operations, net of tax	—	—	—	14,699	—	12,357	2,663	—	(4,393)	25,326
Net income/(loss)	231,479	42,278	42,688	(17,983)	12,345	67,768	7,456	56,477	(275,028)	167,480

Note 11 — Income Taxes

Income tax expense for the three and nine months ended September 30, 2005 was $8.5 million and $21.2 million, respectively, compared to a tax expense of $14.6 million and $65.1 million, respectively, for the corresponding periods in 2004. The income tax expense for the nine months ended September 30, 2005 includes domestic tax expense of $5.7 million and foreign tax expense of $15.5 million. The tax expense for the nine months ended September 30, 2004 includes domestic tax expense of $54.8 million and foreign tax expense of $10.3 million.

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

	Nine Months Ended September 30			
	2005		2004	
	Amount	Rate	Amount	Rate
	(Dollars in thousands)			
Income From Continuing Operations Before Income Taxes	$ 28,192		$ 207,290	
Tax	9,867	35.0%	72,552	35.0%
State taxes	(4,129)	(14.7)%	5,916	2.9%
Foreign operations	(20,508)	(72.7)%	(13,112)	(6.3)%
Permanent differences including subpart F income	11,554	41.0%	—	0%
Valuation allowance	19,790	70.2%	—	0%
Foreign repatriation pursuant to Jobs Act	6,724	23.8%	—	0%
Domestic production activities deduction	(1,553)	(5.5)%	—	0%
Other	(544)	(1.9)%	(220)	(0.2)%
Income Tax Expense	$ 21,201	75.2%	$ 65,136	31.4%

The effective income tax rate for the nine months ended September 30, 2005 differs from the U.S. statutory rate of 35% due to the U.S. income inclusion upon the sale of Enfield, the taxable portion of a dividend from foreign operations repatriated pursuant to the American Jobs Creation Act of 2004, or the Jobs Act, the application of a valuation allowance and partially offset due to earnings in foreign jurisdictions taxed at rates lower than the U.S. statutory rate.

For U.S. income tax purposes, NRG generated additional net deferred tax assets of $216 million for the nine months ended September 30, 2005 of which a valuation allowance of $172 million was applied due to the uncertainty of utilization in future periods.

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 historical operations, current operations, projected future taxable income, projected operating and capital gains and our available tax planning strategies. During the three months ended September 30, 2005, net deferred tax assets of approximately $44 million were generated for which no valuation allowance was established. The net deferred tax assets consist primarily of SFAS No.133 mark-to-market adjustments and utilization of carryover net operating losses to the extent of taxable income generated for the nine months ended September 30, 2005. As of September 30, 2005, a consolidated valuation allowance of $861 million was recorded against the net deferred tax assets.

Pursuant to the Jobs Act, NRG may elect to deduct 85% of certain eligible dividends received from non-U.S. subsidiaries from its taxable income before the end of 2005 if those dividends are reinvested in the U.S. for eligible purposes. During the three month period ended September 30, 2005, NRG repatriated approximately $271 million of accumulated foreign earnings. Only a portion of this amount represents the current earnings and profits which will result in approximately $6.7 million of tax expense. To the extent that NRG does not provide deferred income taxes for unremitted earnings, it is management's intent to permanently reinvest those earnings overseas in accordance with Accounting Principle Board Opinion No. 23 *Accounting for Income Taxes-Special Areas*, or APB No. 23.

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 noncontributory, defined benefit pension plan effective January 1, 2004, with credit for service since 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 September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
	(In thousands)			
Service cost benefits earned	$ 2,318	$ 2,577	$ 8,381	$ 8,477
Interest cost on benefit obligation	964	691	2,835	2,167
Expected return on plan assets	(95)	(22)	(257)	(22)
Curtailment gain	—	—	(335)	—
Net periodic benefit cost	$ 3,187	$ 3,246	$ 10,624	$ 10,622

	Other Benefits			
	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
	(In thousands)			
Service cost benefits earned	$ 279	$ 372	$ 1,254	$ 1,302
Interest cost on benefit obligation	634	671	2,096	1,931
Amortization of net (gain)/loss	(38)	—	—	—
Net periodic benefit cost	$ 875	$ 1,043	$ 3,350	$ 3,233

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'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'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 originally commenced in 2000 and 2001, 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. On July 22, 2005, based upon the filed rate doctrine and federal preemption, the court dismissed NRG Energy, Inc. without prejudice leaving only subsidiaries of WCP remaining in the case. On October 3, 2005, the court sustained defendants' demurrer dismissing the case against all remaining defendants. The plaintiffs have 60 days to file an appeal.

On February 25, 2005, in respect of the Northern California cases that originally commenced in 2002, 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 on March 11, 2002, 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, 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 is named, we are defending the case and bear our own costs of defense.

FERC Proceedings

There are 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. The CDWR claim involves a February 2002 complaint filed by the State of California demanding that FERC 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 of the State of California 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.

Canadian Claim

On June 30, 2005, three individuals filed a lawsuit with the Ontario Superior Court of Justice against more than 20 power generating entities in the U.S. and Canada including the Keystone and Conemaugh facility ownership groups. Two of our subsidiaries own less than four percent of each of these Pennsylvania coal-fired plants. The Plaintiffs have alleged air pollution and associated health effects on behalf of a purported class action on behalf of Ontario residents and asserted damages in excess of CA$50 billion (US $43.1 billion). Neither of our subsidiaries have been served with the lawsuit.

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 favorable to NRG 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 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 in the U.S. District Court for Connecticut for amounts it claimed were owed for congestion charges under the October 29, 1999 Standard Offer Services Contract. CL&P withheld approximately $30 million from amounts owed to PMI under 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.

On October 24, 2005, the U.S. Court of Appeals for the Second Circuit issued its opinion in New York Public Interest Research Group (NYPIRG) v. Stephen L. Johnson, Administrator, U.S. Environmental Protection Agency. In 2000, the NYSDEC issued a notice of violation (NOV) to the prior owner of the Huntley and Dunkirk stations. After an unsuccessful challenge to the stations' Title V air quality permits by NYPIRG, it appealed. The Second Circuit held that, during the Title V permitting process for the two stations, the 2000 NOV should have been sufficient for the NYSDEC to have made a finding that the stations were out of compliance. Accordingly, the court stated that EPA should have objected to the Title V permits on that basis and the permits should have included compliance schedules. As discussed above, on June 3, 2005, the consent decree among NYSDEC, NiMo, and the Company was entered, settling the substantive issues discussed by the Second Circuit in its decision. NYSDEC is in the process of incorporating the consent decree obligations into the Huntley and Dunkirk Title V permits so as to make them permit conditions, an action we believe is supported by the decision. The parties have 45 days to request an en banc rehearing by the Second Circuit.

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 contingent loss from this case is approximately $24.9 million, and at this time we believe we are adequately reserved. 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 obligations over 30 calendar day periods 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. NiMo and the other petitioners filed their brief on September 22, 2005. FERC's brief is due November 21, 2005, and the generators' brief is due on December 12, 2005.

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 contingent loss from this case could exceed $4.8 million, and at this time we believe we are adequately reserved.

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

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 US $80 million. On September 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 in arbitration by Itiquira in September of 2002 and pertains to certain matters arising under the engineering, procurement, and construction contract between the parties. Itiquira sought Real 140 million and asserted that Inepar breached the contract. Inepar sought Real 39 million and alleged that Itiquira breached the contract. On September 2, 2005, the arbitration panel ruled in favor of Itiquira awarding it Real 139 million (US $62.3 million) and Inepar Real 4.7 million (US $2.1 million). Due to interest accrued from the commencement of the arbitration to the award date, Itiquira's award is increased to approximately Real 227 million (US $100 million). Itiquira has commenced the lengthy process in Brazil to execute on the arbitral award. We are unable to predict the outcome of this execution process. On

October 14, 2005, Inepar filed with the arbitration panel a request for clarifications of the ruling. Itiquira has 30 days to respond to Inepar's request. Due to the uncertainty of the collection process, we are accounting for receipt of any amounts as a gain contingency.

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 yet to schedule a hearing or rule on the CFTC's pending motion to reinstate its expunged claim. 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 for the Eighth Circuit. The CFTC filed its brief on August 9, 2005, and on September 29, 2005 we filed our brief.

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 of 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 $6.9 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 be approximately $1.1 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.

In September 2001, we experienced an underground fuel line leak at our Vienna Generating Station, resulting in a small release of oil free product, which was contained. The Company promptly reported the event to the relevant state agencies and continues to work with the Maryland Department of the Environment, or DEP, to develop any remediation requirements. Ongoing monitoring has indicated that the product is stable. The Company submitted a site assessment report and proposed remediation plan to Maryland DEP but the agency has not formally responded to those documents. Based upon work completed by a remediation contractor retained by NRG, long-term clean up liability in connection with this matter is not expected to exceed $0.5 million.

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. NRG has recently resolved a dispute with NYSDEC over the method of calculation for stipulated penalties. NRG expects to pay NYSDEC $1.3 million in the fourth quarter to cover the stipulated penalty payments that had been withheld by the Company pending resolution of the dispute. This amount has been fully reserved for in NRG's accounts.

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 NOx controls, as well as installation of "Best Technology Available", or BTA, under the Phase II 316(b) Rule.

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 $5.2 million. Annual payments are made to the fund in the amount of $0.12 million.

At the end of 2004, we estimated environmental capital expenditures of approximately $149 million for our 2005 through 2010 plan at our South Central facilities. These expenditures are primarily related to installation of particulate, SO_2 and NOx 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 Southern California Edison, or SCE, and San Diego Gas & Electric, or 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 Los Angeles Regional Water Quality Control Board will allow contaminated soils to remain underneath the building foundation until the building is demolished.

Hurricanes Katrina and Rita

In September 2005, Hurricanes Katrina and Rita roiled the South Central region's power markets. Although our assets only sustained an approximate $1.2 million in damages, four of our region's 11 cooperative customers suffered extensive losses to their distribution systems and the region suffered a drop in contract sales during the ensuing power outages. The load loss and the transmission constraints had offsetting impacts on our South Central region's margins resulting in a $4 million in lost sales. In addition, NRG created a reserve for a receivable from Entergy New Orleans of $1.9 million because of their hurricane-related bankruptcy.

The reduced demand occurred during an unusually hot September, conditions in which our South Central region would otherwise normally be expected to purchase significant amounts of energy to cover its contract load obligations. Heavy damage to Entergy's transmission system coupled with Entergy's difficulty scheduling transmission resources limited our region's ability to sell power into the merchant market. We are evaluating the future impact of these hurricanes to our results of operations, financial condition and cash flows.

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. In February 2005, NRG Power Marketing, Inc., or PMI, entered into a ten-year operating lease agreement with GE Railcar Services Corporation, or GE, for the lease of 1,500 railcars. The lease was amended on August 2, 2005 to include an additional 40 railcars bringing the total number of leased railcars to 1,540. Delivery of the railcars commenced in February 2005 and was completed in August 2005. We have assigned certain of our rights and obligations for the 1,540 railcars under the purchase agreement to GE. Accordingly, the railcars which PMI leases from GE under the arrangement described above were purchased by GE from Freight Car America in lieu of PMI's 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 U.S. Including these contracts and other contracts for all of our plants, total coal purchase obligations increased by $264.8 million, which are expected to be paid over the course of the next five 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, or 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 September 30, 2005 Flinders' had AUD 14.0 million (US $10.7 million) in performance bonds and letters of credit under the new facility. On October 7, 2005 this amount was reduced to AUD 13.5 million (US $10.3 million).

On February 18, 2005, we issued a guarantee to the benefit of General Electric Railcar Service Corporation, which was subsequently amended in August 2005. 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 $52.8 million over the first five years of the lease, and $48.4 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 nine months ended September 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. During this period we have also terminated such guarantees. The total net increase in guarantees is $21.5 million. At this time, we do not believe we will be obligated to perform under these guarantees.

At September 30, 2005, we were contingently obligated for approximately $327.1 million under our funded standby letters of credit facility, and we had $8.3 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 — Convertible Perpetual Preferred Stock

On August 11, 2005, we issued 250,000 shares of 3.625% Convertible Perpetual Preferred Stock, or 3.625% Preferred Stock, to Credit Suisse First Boston Capital LLC, or CSFB, in a private placement. The 3.625% Preferred Stock is recorded based on the proceeds of $250 million net of issuance costs of $3.81 million. This amount will be accreted over a 10 year period to the redemption value of $250 million.

The 3.625% Preferred Stock has a liquidation preference of $1,000 per share. Holders of the 3.625% Preferred Stock are entitled to receive, out of funds legally available, cash dividends at the rate of 3.625% per annum, payable in cash quarterly in arrears commencing on December 15, 2005. Each share of 3.625% Preferred Stock is convertible during the 90-day period beginning August 11, 2015 at the option of NRG or the holder. Holders tendering the 3.625% Preferred Stock for conversion shall be entitled to receive, cash equaling the liquidation preference of $1,000 per share and common stock for the conversion feature. We may elect to make a cash payment in lieu of delivering shares of common stock in connection with such conversion feature, and we may elect to receive cash in lieu of shares of common stock, if any, from the Holder in connection with such conversion feature. If a fundamental change occurs, the holders will have the right to require us to repurchase all or a portion of the 3.625% Preferred Stock for a period of time after the fundamental change at a purchase price equal to 100% of the liquidation preference, plus accumulated and unpaid dividends. The 3.625% Preferred Stock are senior to all classes of common stock, on a parity with our 4% Preferred Stock and junior to all of our existing and future debt obligations and all of our subsidiaries' existing and future liabilities and capital stock held by persons other than NRG or our subsidiaries. The proceeds were used to redeem $228.8 million of Second Priority Notes on September 12, 2005.

Note 16 — Accelerated Share Repurchase Plan

On August 11, 2005, we entered into an Accelerated Share Repurchase Agreement with CSFB, pursuant to which we repurchased $250 million of our common stock on that date that equaled a total of 6,346,788 shares, which are held in treasury. We funded the repurchase with cash on hand. On or about February 13, 2006, we will receive from, or pay to, CSFB a purchase price adjustment based upon the weighted average value of NRG's common stock over a period of approximately six months, subject to a minimum price of 97% and a maximum price of 103% of the closing price per share on August 10, 2005, or $39.39. Based on the analysis of our common stock price volatility, we have recorded a liability of $7.5 million reflecting the maximum purchase price adjustment expected as of February 13, 2006 which we intend to settle in cash, when and if applicable. The total of the initial repurchase price and the purchase price adjustment are recorded in Treasury Stock.

Note 17 — Stock Based Compensation

On August 1, 2005, NRG issued the following instruments to employees under our Long Term Incentive Plan, as per the table below:

Instrument	Number of units	Vesting
Stock options	134,000	Ratably over 3 years
Restricted Stock Units — RSUs	461,600	Cliff vest in 3 years
Performance Units — PUs	45,900	Cliff vest in 3 years

We issued the PUs under our Long Term Incentive Plan. Each PU will be paid out on August 1, 2008 if the Measurement Price, that is the average closing price of NRG's common stock for the ten trading days prior to August 1, 2008, is equal to or greater than the Target Price of $54.50. The payout for each PU will be equal to: (i) one share of common stock, if the Measurement Price equals the Target Price; (ii) a pro-rated amount in between one and two shares of common stock, if the Measurement Price is greater than the Target Price but less than the Maximum Price of $63.75; and (iii) two shares of common stock, if the Measurement Price is equal to or greater than the Maximum Price.

The fair value of the stock option grants and PUs were estimated on the date of grant using the Black-Scholes option-pricing model and the Monte Carlo valuation models, respectively, with the following weighted average assumptions:

	Stock Options	PUs
Dividends per year	—	—
Expected volatility	29.75%	29.75%
Risk free interest rate	4.16%	4.09%
Expected life of stock options (in years)	5	3
Fair value	$13.22	$29.87

The fair value of the RSU grants is based on the closing price of our common stock on the date of grant. All RSUs were granted on August 1, 2005 at a fair value of $38.80 per RSU.

Note 18 — Condensed Consolidating Financial Information

As of September 30, 2005, we have $1.08 billion of Second Priority Notes outstanding. The Second Priority 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 Second Priority 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
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.

NEO California Power LLC
NEO Chester-Gen LLC
NEO Corporation
NEO Freehold-Gen LLC
NEO Landfill Gas Holdings Inc.
NEO Power Services Inc.
Norwalk Power LLC
NRG Affiliate Services Inc.
NRG Arthur Kill Operations Inc.
NRG Asia-Pacific, Ltd.
NRG Astoria Gas Turbine Operations, Inc.
NRG Bayou Cove LLC
NRG Cabrillo Power Operations Inc.
NRG 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
NRG Western Affiliate Services Inc.
Oswego Harbor Power LLC
Saguaro Power LLC
Somerset Operations Inc.
Somerset Power LLC
Vienna 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, 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 consists of parent company operations. Guarantor Subsidiaries and Non-Guarantor Subsidiaries of NRG are reported on an equity basis. For companies acquired, the fair values of the assets and liabilities acquired have been presented on a "push-down" accounting basis.

NRG Energy, Inc. and Subsidiaries

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

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$ 594,413	$ 157,653	$ 14,081	$ (831)	$ 765,316
Operating Costs and Expenses					
Cost of majority-owned operations	541,054	117,316	10,834	(831)	668,373
Depreciation and amortization	33,281	13,154	2,367	—	48,802
General, administrative and development	7,451	10,967	28,767	—	47,185
Corporate relocation charges	—	—	1,740	—	1,740
Impairment charges	6,000	—	—	—	6,000
Total operating costs and expenses	587,786	141,437	43,708	(831)	772,100
Operating Income/(Loss)	6,627	16,216	(29,627)	—	(6,784)
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	(13)	—	—	(13)
Equity in earnings of consolidated subsidiaries	20,225	—	41,569	(61,794)	—
Equity in earnings of unconsolidated affiliates	13,662	15,407	8	—	29,077
Gain on sale of equity method investment	—	4,333	—	—	4,333
Other income, net	2,131	12,489	615	(5,279)	9,956
Refinancing Expense	—	—	(19,012)	—	(19,012)
Interest expense	(46)	(17,974)	(33,050)	5,279	(45,791)
Total other income/(expense)	35,972	14,242	(9,870)	(61,794)	(21,450)
Income (Loss) From Continuing Operations Before Income Taxes	42,599	30,458	(39,497)	(61,794)	(28,234)
Income Tax Expense/(Benefit)	10,539	10,588	(12,616)	—	8,511
Income (Loss)From Continuing Operations	32,060	19,870	(26,881)	(61,794)	(36,745)
Income on Discontinued Operations, net of Income Taxes	10,735	(871)	—	—	9,864
Net Income (Loss)	$ 42,795	$ 18,999	$ (26,881)	$ (61,794)	$ (26,881)

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

NRG Energy, Inc. and Subsidiaries

Condensed Consolidating Statements of Operations
For the Nine Months Ended September 30, 2005
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$ 1,474,568	$ 429,754	$ 42,190	$ (3,684)	$ 1,942,828
Operating Costs and Expenses					
Cost of majority-owned operations	1,203,429	327,198	28,794	(3,684)	1,555,737
Depreciation and amortization	99,749	37,778	6,790	—	144,317
General, administrative and development	30,129	25,265	94,247	—	149,641
Corporate relocation charges	—	—	5,651	—	5,651
Impairment charges	6,223	—	—	—	6,223
Total operating costs and expenses	1,339,530	390,241	135,482	(3,684)	1,861,569
Operating Income/(Loss)	135,038	39,513	(93,292)	—	81,259
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	(36)	—	—	(36)
Equity in earnings of consolidated subsidiaries	88,444	—	194,830	(283,274)	—
Equity in earnings of unconsolidated affiliates	29,703	52,779	19	—	82,501
Gain on sales of equity method investments	—	15,894	—	—	15,894
Other income, net	5,059	48,104	5,530	(15,485)	43,208
Refinancing expense	—	9,783	(53,819)	—	(44,036)
Interest expense	(277)	(56,496)	(109,310)	15,485	(150,598)
Total other income (expense)	122,929	70,028	37,250	(283,274)	(53,067)
Income/(Loss) From Continuing Operations Before Income Taxes	257,967	109,541	(56,042)	(283,274)	28,192
Income Tax Expense/(Benefit)	80,230	16,616	(75,645)	—	21,201
Income From Continuing Operations	177,737	92,925	19,603	(283,274)	6,991
Income from Discontinued Operations, net of Income Taxes	10,735	1,877	—	—	12,612
Net Income	$ 188,472	$ 94,802	$ 19,603	$ (283,274)	$ 19,603

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

NRG Energy, Inc. and Subsidiaries

Condensed Consolidating Balance Sheet
September 30, 2005
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy	Eliminations(1)	Consolidated Balance
			(In thousands)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ (4,485)	$ 131,574	$ 377,247	$ —	$ 504,336
Restricted cash	2,849	88,659	—	—	91,508
Accounts receivable, net	244,662	56,730	7,447	—	308,839
Current portion of notes receivable	—	24,633	435,519	(435,218)	24,934
Income taxes receivable	(331)	2	31,566	—	31,237
Inventory	173,077	29,066	1,404	—	203,547
Derivative instruments valuation	430,398	16,828	4,319	—	451,545
Prepayments and other current assets	53,720	21,742	54,041	(214)	129,289
Collateral on deposit in support of energy risk management activities	631,436	—	—	—	631,436
Deferred income taxes	149,548	(292)	(105,724)	1,300	44,832
Total current assets	1,680,874	368,942	805,819	(434,132)	2,421,503
Net property, plant and equipment	2,175,945	1,023,856	26,913	—	3,226,714
Other Assets					
Investment in subsidiaries	800,211	—	3,445,349	(4,245,560)	—
Equity investments in affiliates	292,616	358,411	385	—	651,412
Notes receivable, less current portion	103,532	711,043	977	(103,532)	712,020
Intangible assets, net	246,514	22,383	—	—	268,897
Derivative instruments valuation	24,818	7,155	—	—	31,973
Funded letter of credit	—	—	350,000	—	350,000
Other non-current assets	22,262	19,883	90,703	—	132,848
Total other assets	1,489,953	1,118,875	3,887,414	(4,349,092)	2,147,150
Total Assets	$ 5,346,772	$ 2,511,673	$ 4,720,146	$ (4,783,224)	$ 7,795,367
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt	$ 426,417	$ 90,681	$ 94,144	$ (435,218)	$ 176,024
Accounts payable	22,300	(119,218)	249,918	(32)	152,968
Derivative instruments valuation	957,035	16,108	—	—	973,143
Other bankruptcy settlement	—	175,945	—	—	175,945
Accrued expenses and other current liabilities	148,806	76,983	163,821	(214)	389,396
Total current liabilities	1,554,558	240,499	507,883	(435,464)	1,867,476
Other Liabilities					
Long-term debt and capital leases	189	1,098,996	1,870,721	(103,532)	2,866,374
Deferred income taxes	(54,231)	103,896	52,234	1,300	103,199
Derivative instruments valuation	82,149	99,752	16,653	—	198,554
Out-of-market contracts	302,639	—	—	—	302,639
Other non-current liabilities	131,625	51,976	7,296	—	190,897
Total non-current liabilities	462,371	1,354,620	1,946,904	(102,232)	3,661,663
Total liabilities	2,016,929	1,595,119	2,454,787	(537,696)	5,529,139
Minority interest	—	869	—	—	869
3.65% Convertible Perpetual Preferred Stock	—	—	246,191	—	246,191
Stockholders' Equity	3,329,843	915,685	2,019,168	(4,245,528)	2,019,168
Total Liabilities and Stockholders' Equity	$ 5,346,772	$ 2,511,673	$ 4,720,146	$ (4,783,224)	$ 7,795,367

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

NRG Energy, Inc. and Subsidiaries

Condensed Consolidating Statements of Cash Flows
For the Nine Months Ended September 30, 2005 (Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income	$ 188,472	$ 94,802	$ 19,603	$ (283,274)	$ 19,603
Adjustments to reconcile net income to net cash provided (used) by operating activities					
Distribution s in excess of (less than) equity in earnings of unconsolidated affiliates and consolidated subsidiaries	(53,658)	(33,772)	304,455	(215,925)	1,100
Depreciation and amortization	99,749	38,538	6,789	—	145,076
Reserve for note and interest receivable	—	(98)	—	—	(98)
Amortization of financing costs and debt premium	—	4,696	2,955	—	7,651
Write-off of deferred financing costs and debt premium	—	(9,783)	2,082	—	(7,701)
Deferred income taxes	(171,660)	(4,329)	122,384	—	(53,605)
Minority interest	—	899	—	—	899
Unrealized (gains)/losses on derivatives	245,060	3,658	3,538	—	252,256
Asset impairment	6,223	—	—	—	6,223
Write downs and gains/losses on sale of equity method investments	—	(15,894)	—	—	(15,894)
Gain on TermoRio settlement	—	(13,532)	—	—	(13,532)
Gain on sale of discontinued operations	—	(10,735)	—	—	(10,735)
Amortization of power contracts and emission credits	11,256	4,862	—	—	16,118
Amortization of unearned equity compensation	1,884	355	6,165	—	8,404
Collateral deposit payments in support of energy risk management activities	(598,111)	—	—	—	(598,111)
Cash used by changes in other working capital, net of disposition affects	314,505	(401,660)	215,699	—	128,544
Net Cash Provided/(Used) by Operating Activities	43,720	(341,993)	683,670	(499,199)	(113,802)
Cash Flows from Investing Activities					
Proceeds on sale of equity investments	—	69,575	—	—	69,575
Proceeds on sale of discontinued operations	—	35,658	—	—	35,658
Return of capital from equity investments	23	1,310	—	—	1,333
Decrease/(increase) in notes receivable	305,166	224,925	(429,737)	—	100,354
Capital expenditures	(32,163)	(10,433)	(2,922)	—	(45,518)
Decrease in restricted cash and trust funds	871	17,044	—	—	17,915
Net Cash Provided/(Used) by Investing Activities	273,897	338,079	(432,659)	—	179,317
Cash Flows from Financing Activities					
Payments for dividends	(477,885)	(21,314)	(12,272)	499,199	(12,272)
Net borrowings in revolving line of credit	—	—	80,000	—	80,000
Repayment of minority interest obligations	—	(3,581)	—	—	(3,581)
Accelerated share repurchase payment, net	—	—	(250,717)	—	(250,717)
Issuance of 3.625% Preferred Stock, net	—	—	246,126	—	246,126
Deferred debt issuance costs	—	(1,078)	(461)	—	(1,539)
Issuance expense of 4% Preferred Stock	—	—	(204)	—	(204)
Proceeds from issuance of long-term debt, net	—	249,139	—	—	249,139
Principal payments on debt	(12)	(331,404)	(647,963)	—	(979,379)
Net Cash Used by Financing Activities	(477,897)	(108,238)	(585,491)	499,199	(672,427)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	(481)	—	—	(481)

Change in Cash from Discontinued Operations	—	8,051	—	—	8,051
Change in cash and cash equivalents	(160,280)	(104,582)	(334,480)	—	(599,342)
Cash and Cash Equivalents at Beginning of Period	155,795	236,156	711,727	—	1,103,678
Cash and Cash Equivalents at End of Period	$ (4,485)	$ 131,574	$ 377,247	$ —	$ 504,336

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

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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	$ 236,156	$ 711,727	$ —	$ 1,103,678
Restricted cash	3,720	105,913	—	—	109,633
Accounts receivable, net	182,340	80,267	7,004	—	269,611
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	70,566	24,977	42,893	(2,916)	135,520
Collateral on deposit in support of energy risk management activities	33,325	—	—	—	33,325
Current assets — discontinued operations	(88)	15,909	—	—	15,821
Total current assets	742,350	569,502	811,848	(5,412)	2,118,288
Net property, plant and equipment	2,243,558	1,054,466	30,780	196	3,329,000
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	1,037,356	977	(642,581)	804,450
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	21,837	53,331	—	111,574
Non-current assets — discontinued operations	—	45,884	—	—	45,884
Total other assets	1,807,311	1,585,015	4,326,524	(5,335,855)	2,382,995
Total Assets	$ 4,793,219	$ 3,208,983	$ 5,169,152	$ (5,341,071)	$ 7,830,283
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt	$ 16	$ 97,883	$ 415,855	$ (2,496)	$ 511,258
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	37,370	50,051	(2,916)	209,367
Current liabilities — discontinued operations	—	2,912	—	—	2,912
Total current liabilities	545,343	275,911	271,182	(4,495)	1,087,941
Other Liabilities					
Long-term debt	202	1,726,798	2,128,177	(642,581)	3,212,596
Deferred income taxes	(32,379)	131,227	35,732	—	134,580
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	—	47,759	—	—	47,759
Total non-current liabilities	408,394	2,077,863	2,205,806	(642,581)	4,049,482
Total liabilities	953,737	2,353,774	2,476,988	(647,076)	5,137,423
Minority interest	—	696	—	—	696
Stockholders' Equity	3,839,482	854,513	2,692,164	(4,693,995)	2,692,164
Total Liabilities and Stockholders ' Equity	$ 4,793,219	$ 3,208,983	$ 5,169,152	$ (5,341,071)	$ 7,830,283

(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 September 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	$ 429,952	$ 163,763	$ 12,437	$ (1,520)	$ 604,632
Operating Costs and Expenses					
Cost of majority-owned operations	266,883	105,224	9,268	(1,520)	379,855
Depreciation and amortization	33,375	14,345	3,340	—	51,060
General, administrative and development	30,611	8,618	14,807	(5)	54,031
Corporate relocation charges	1	—	5,712	—	5,713
Reorganization charges	149	(33)	(5,361)	—	(5,245)
Impairment charges	987	24,520	15,000	—	40,507
Total operating costs and expenses	332,006	152,674	42,766	(1,525)	525,921
Operating Income/(Loss)	97,946	11,089	(30,329)	5	78,711
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	(18)	—	—	(18)
Equity in earnings of consolidated subsidiaries	27,641	—	142,448	(170,089)	—
Equity in earnings of unconsolidated affiliates	31,738	21,576	59	—	53,373
Write downs and gain/(losses) on sales of equity method investments	(13,525)	1	—	—	(13,524)
Other income, net	866	4,237	397	(22)	5,478
Interest expense	(400)	(19,475)	(46,252)	17	(66,110)
Total other income (expense)	46,320	6,321	96,652	(170,094)	(20,801)
Income From Continuing Operations Before Income Taxes	144,266	17,410	66,323	(170,089)	57,910
Income Tax Expense	420	1,737	12,402	—	14,559
Income From Continuing Operations	143,846	15,673	53,921	(170,089)	43,351
Income from discontinued operations, net of income taxes	3,523	7,047	300	—	10,870
Net Income	$ 147,369	$ 22,720	$ 54,221	$ (170,089)	$ 54,221

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

NRG Energy, Inc. and Subsidiaries

Condensed Consolidating Statements of Operations
For the Nine Months Ended September 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	$ 1,278,184	$ 459,292	$ 38,463	$ (5,270)	$ 1,770,669
Operating Costs and Expenses					
Cost of majority-owned operations	786,838	306,357	24,554	(5,270)	1,112,479
Depreciation and amortization	99,764	48,998	9,841	—	158,603
General, administrative and development	74,296	22,907	38,470	—	135,673
Corporate relocation charges	2	—	12,472	—	12,474
Reorganization charges	1,312	118	(3,086)	—	(1,656)
Impairment charges	2,663	24,520	15,000	—	42,183
Total operating costs and expenses	964,874	402,900	97,251	(5,270)	1,459,756
Operating Income/(Loss)	313,309	56,392	(58,788)	—	310,913
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	(18)	—	—	(18)
Equity in earnings of consolidated subsidiaries	74,577	—	299,669	(374,246)	—
Equity in earnings/(losses) of unconsolidated affiliates	65,609	52,328	(750)	—	117,187
Write downs and gains/(losses) on sales of equity method investments	(13,525)	(1,270)	738	—	(14,057)
Other income, net	4,524	16,239	3,421	(7,039)	17,145
Refinancing expense	—	—	(30,417)	—	(30,417)
Interest expense	187	(66,126)	(134,563)	7,039	(193,463)
Total other income (expense)	131,372	1,153	138,098	(374,246)	(103,623)
Income From Continuing Operations Before Income Taxes	444,681	57,545	79,310	(374,246)	207,290
Income Tax Expense/(Benefit)	139,901	13,405	(88,170)	—	65,136
Income From Continuing Operations	304,780	44,140	167,480	(374,246)	142,154
Income from discontinued operations, net of Income Taxes	3,319	22,007	—	—	25,326
Net Income	$ 308,099	$ 66,147	$ 167,480	$ (374,246)	$ 167,480

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

NRG Energy, Inc. and Subsidiaries

Condensed Consolidating Statements of Cash Flows
For the Nine Months Ended September 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	308,099	66,147	167,480	(374,246)	167,480
Adjustments to reconcile net income to net cash provided by operating activities					
Distribution s in excess of (less than) equity in earnings of unconsolidated affiliates and consolidated subsidiaries	(41,948)	(47,236)	(174,065)	249,546	(13,703)
Depreciation and amortization	99,764	55,267	9,841	—	164,872
Reserve for note and interest receivable	—	4,572	—	—	4,572
Amortization of debt issuance costs and debt discount	—	5,131	17,682	—	22,813
Write off of deferred finance cost /(debt premium)	—	—	15,312	—	15,312
Deferred income taxes	(64,259)	20,553	111,361	—	67,655
Minority interest	—	1,961	—	—	1,961
Unrealized (gains)/losses on derivatives	386	(33,206)	(412)	—	(33,232)
Asset impairment	2,663	24,520	15,000	—	42,183
Write downs and (gain)/loss on sales of equity method investments	13,525	1,270	(738)	—	14,057
Gain on sale of discontinued operations	439	(30,363)	—	—	(29,924)
Amortization of power contracts and emission credits	13,267	29,555	—	—	42,822
Amortization of unearned equity compensation	1,568	230	8,735	—	10,533
Collateral deposit payments in support of energy risk management activities	(28,783)	—	—	—	(28,783)
Cash provided (used) by changes in other working capital items, net of disposition affects	(1,211)	(93,606)	241,620	—	146,803
Net Cash Provided (Used) by Operating Activities	303,510	4,795	411,816	(124,700)	595,421
Cash Flows from Investing Activities					
Proceeds on sale of equity method investments	—	29,693	—	—	29,693
Proceeds on sale of discontinued operations	—	246,498	—	—	246,498
Return of capital from (investments in) equity methods investments and projects	1,757	(13,969)	11,540	—	(672)
Decrease in note receivable, net	(28,222)	64,831	—	—	36,609
Capital expenditures	(49,606)	(6,106)	(22,581)	—	(78,293)
Increase/(decrease) in restricted cash and trust funds	(11,412)	(11,712)	95	—	(23,029)
Investment in subsidiaries	—	—	(92,000)	92,000	—
Net Cash Provided/(Used) by Investing Activities	(87,483)	309,235	(102,946)	92,000	210,806
Cash Flows from Financing Activities					
Proceeds from issuance of long-term debt	94	39,888	491,225	—	531,207
Deferred debt issuance costs	—	53	(8,550)	—	(8,497)
Principal payments on short and long-term debt	—	(241,619)	(508,724)	—	(750,343)
Dividends to parent	(104,700)	(20,000)	—	124,700	—
Capital contributions from parent	92,000	—	—	(92,000)	—
Net Cash Provided /(Used) by Financing Activities	(12,606)	(221,678)	(26,049)	32,700	(227,633)
Change in Cash from Discontinued Operations	—	(26,486)	—	—	(26,486)
Effect of Exchange Rate Changes on cash and cash equivalents	—	(2,507)	—	—	(2,507)
Change in cash and cash equivalents	203,421	63,359	282,821	—	549,601

Cash and cash equivalents at Beginning of Period	295,509	158,392	95,280	—	549,181
Cash and cash equivalents at End of Period	$ 498,930	$ 221,751	$ 378,101	$ —	$ 1,098,782

(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, 19% 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. From time to time we may also consider and undertake other merger and acquisition transactions that are consistent with our strategy, such as the Texas Genco acquisition discussed below.

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 in compliance with applicable regulatory requirements. 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 September 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 September 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. Cal ISO allowed a switch to RMR Condition I, which allows 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. WCP was notified by the Cal ISO that effective January 1, 2006, Encina unit 4 and El Segundo units 3 and 4 were not being relisted as RMR qualifying facilities. A tolling agreement for the total capacity of the El Segundo plant has been executed with a major load serving entity for the period May 2006 through April 2008. With the loss of RMR designation, the Cal ISO no longer has the right to call on the facility as a reliability resource.

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.

Texas Genco Acquisition

On September 30, 2005, we entered into an Acquisition Agreement with Texas Genco LLC, a Delaware limited liability company, or Texas Genco, and each of the direct and indirect owners of Texas Genco, referred to as the Sellers. Pursuant to the Acquisition Agreement, NRG agreed to purchase all of the outstanding equity interests in Texas Genco for a total purchase price of $5.825 billion, which includes the assumption by the Company of approximately $2.5 billion of indebtedness. The purchase price is subject to adjustment, and includes an equity component valued at $1.8 billion based on a price per share of $40.50 of NRG's common stock. As a result of the Acquisition, Texas Genco will become a wholly owned subsidiary of NRG and will nearly double NRG's U.S. generation portfolio from 12,981 Megawatts to 23,920 Megawatts.

Pending closing of the Acquisition, Texas Genco and NRG are obligated to conduct their businesses in the ordinary course of business, to preserve the business, assets, properties and relationships, and to refrain from certain activities without prior written consent of the other party, such consent not to be unreasonably withheld or delayed. NRG is devoting substantial resources to satisfying conditions precedent, arranging financing, closing the Acquisition and planning the integration of the combined companies post-closing.

Of the approximately $5.825 billion payable to the Sellers upon consummation of the Acquisition, NRG will pay $4.025 billion in cash, subject to adjustment, and issue a minimum of 35,406,320 shares of NRG's common stock. At NRG's election, the remaining consideration may be comprised of an additional 9,038,125 shares of common stock, or at NRG's election the equivalent in the form of a combination of common stock, additional cash and shares of a new series of NRG's Cumulative Redeemable Preferred Stock. NRG expects to finance the Acquisition through a combination of a new senior secured credit facility, an unsecured high yield notes offering and the sale of common and preferred equity securities in the public markets. Subject to the satisfaction of certain customary conditions, the Acquisition is expected to be consummated in the first quarter of 2006.

In connection with the planned acquisition of Texas Genco, on October 14, 2005, the Company and Texas Genco filed an application with the Nuclear Regulatory Commission seeking consent to the indirect transfer of control of Texas Genco's licenses to own a 44% interest in the South Texas Project Electric Generating Station, units 1 and 2. The proposed transaction is subject to review and approval by the Federal Energy Regulatory Commission, or FERC, and an application for approval of the acquisition in accordance with Federal Power Act was filed on October 24, 2005. Also, notifications have been filed with the Federal Trade Commission and the Department of Justice under the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

Hurricanes Katrina and Rita

In September 2005, Hurricanes Katrina and Rita roiled the South Central region's power markets. Although our assets only sustained an approximate $1.2 million in damages, four of our region's 11 cooperative customers suffered extensive losses to their distribution systems and the region suffered a drop in contract sales during the ensuing power outages. The load loss and the transmission constraints had offsetting impacts on our South Central region's margins resulting in a $4 million in lost sales. In addition, NRG created a reserve for a receivable from Entergy New Orleans of $1.9 million because of their hurricane-related bankruptcy.

The reduced demand occurred during an unusually hot September, conditions in which our South Central region would otherwise normally be expected to purchase significant amounts of energy to cover its contract load obligations. Heavy damage to Entergy's transmission system coupled with Entergy's difficulty scheduling transmission resources limited our region's ability to sell power into the merchant market. We are evaluating the future impact of these hurricanes to our results of operations, financial condition and cash flows.

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 May 18, 2005, the US Environmental Protection Authority, or USEPA, published the Clean Air Mercury Rule, or CAMR, to permanently cap and reduce mercury emissions from coal-fired power plants. 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 the 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), fourteen states, together with five environmental organizations, have filed petitions for reconsideration of CAMR. The states (including California, Connecticut, Delaware, Illinois, Maine, Massachusetts, New Hampshire, New Jersey, New Mexico, New York, Pennsylvania, Rhode Island, Vermont and Wisconsin) allege that the rule violates the Clean Air Act, or 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 challenging CAMR, although this was narrowly defeated in the Senate on September 13, 2005. Independently, on October 21, 2005 the USEPA granted requests to reconsider seven specific aspects of CAMR (including state allocations). Each of our coal-fired electric power plants will be subject to mercury regulation. However, since the rule has yet to be implemented by individual states, it is not possible to identify in detail how CAMR will affect our operations. Nevertheless, we continue to actively review emerging mercury monitoring and mitigation technologies to identify the most cost-effective options for the Company in implementing 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 from CAMR based on 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 lodged legal challenges to the USEPA's delisting rule and the agency has agreed to reconsider this delisting, although it has not specified which issues will be reconsidered. 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. USEPA is scheduled to hold a public hearing on its reconsideration of both CAMR and the nickel MACT rules on November 17, 2005.

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 NOx emissions from power plants in two phases (2010 and 2015 for SO_2 and 2009 and 2015 for NOx). CAIR will apply to certain of the Company's power plants in New York, Massachusetts, Connecticut, Delaware, Louisiana, Illinois, Pennsylvania and Maryland. 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. On August 24, 2005 the USEPA published a proposed Federal Implementation Plan (FIP) to ensure that generators affected by CAIR reduce emissions on schedule. The FIP requires states to meet required CAIR emissions reductions through the CAIR cap-and-trade program. In parallel, on September 9, 2005 the USEPA proposed a rule to address attainment for fine particulates ("NAAQS for PM2.5") that will require affected states to implement further rules to address SO_2 and NOx emissions (as precursors of fine particulates in the atmosphere). 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 CAIR rule as issued by the USEPA, together with the FIP and NAAQS for PM2.5 requirements, are actually implemented by specific state legislation, it is not possible to identify with greater specificity the effect of CAIR on the Company's plants. However, investments in additional backend control technologies may be required and the Company continues to evaluate these issues. Additionally, eight petitions have been filed seeking reconsideration of CAIR by the USEPA. As of October 25, 2005, there has been no action from USEPA in response to these petitions.

In 2004, the 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 Air Visibility Rule (or so-called BART rule) was published by the USEPA on July 6, 2005. It contains BART requirements and guidelines and provides states with several options for determining whether sources should be subject to BART. States must develop implementation plans by December 2007 which, according to proposed revisions published by USEPA on August 1, 2005, may be satisfied through an emissions trading program. The BART rule will affect many of the Company's facilities, although consistent with analysis released by the USEPA, states which adopt the CAIR cap-and-trade program for SO_2 and NOx can apply CAIR controls to also satisfy BART, since emissions reductions required under CAIR are generally 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 Air Visibility Rule beyond those required by CAIR.

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 filed suit against the USEPA seeking confirmation that the 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 (in *Commonwealth of Massachusetts v. EPA*) supported the USEPA's opinion that it lacks authority to regulate GHGs from motor vehicles, although avoiding the broader issue of whether USEPA has authority, or an obligation, to regulate GHGs under the CAA. On September 1, 2005, five states requested reconsideration of this dismissal. While the specific issue under consideration is the USEPA's obligation to require GHG cuts from mobile sources, any decision implying that the USEPA has an obligation to regulate GHGs under the CAA has wider implications for the power generation sector. In 2004, eight states and the City of New York filed suit 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 (*Connecticut v. AEP*). An injunction was sought against each defendant to force it to abate its contribution to the "global warming nuisance" by requiring CO_2 emissions caps and annual reductions in those caps for at least a decade. On September 15, 2005, the public nuisance case was dismissed on the basis that the claims made raised "political questions" reserved to the legislative and executive branches of the federal government. The initiation of GHG-related litigation and proposed legislation is becoming more frequent, although the outcomes of such suits 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 scheduled 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 the program to start in 2009, with a review in 2015 and an assessment of further reductions after 2020. The proposal involves an overall RGGI cap (with state sub-caps) based on CO_2 emissions for the period 2000 to 2004. That cap, referred to as "stabilization", will remain the same through 2015, with a 10% reduction between 2015 and 2020. Decisions on allowance allocations will be made by each state, although at least 25% of the state allocations will be set aside for public purposes, suggesting that from implementation, generators in the RGGI region may receive an allocation of allowances that is materially less than required to cover existing emissions, potentially having a significant effect on the cost of operations. While the final parameters of RGGI are still under active debate in the industry and with state agencies, it is clear that 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 January 1, 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 and no general implementing regime in existence, 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 2009 may be the earliest year when such a carbon credit market exists, pursuant to RGGI. Given the regulatory uncertainty surrounding implementation of Massachusetts's carbon market and the corresponding costs of CO_2 credits when that market exists, 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. 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 redoubled 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 for power plants that exceed those under CAIR. The OTC targets and timelines are as follows: (a) through September 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, the 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)/Prevention of Significant Deterioration (PSD) 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 Appeals held in favor of Duke's position as to what type of modification triggers NSR and Prevention of Significant Deterioration provisions. Rehearing petitions that were filed in this matter by the Department of Justice and some environmental groups were denied on August 30, 2005. 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. However, divergent rulings are emerging on NSR issues across the country, with courts in Ohio and Indiana providing interpretations of the NSR provisions different from those in the Duke and Alabama cases. On August 29, 2005 the court ruled in *US v. Cinergy* in favor of the USEPA and specifically rejected the conclusion in the Duke case.

In an effort to codify the legal requirements in this area (i.e., what amounts to a major modification and what emissions tests apply), USEPA issued its NSR Reform Rule on December 31, 2002, although its implementation was stayed by court order on December 24, 2003. There have been a number of legal challenges to different aspects of the proposed rule. On October 13, 2005 USEPA proposed changes to its NSR permitting program to stipulate a standard based on power plants' hourly emission rates, as opposed to a cumulative measure of annual emissions. The proposed change must undergo a 60-day comment period. Given the divergent cases and rules in this area (at both the federal and state levels), it is difficult to predict with certainty the parameters of the final NSR/PSD regime. In the meantime, the Company continues to analyze all proposed projects at its facilities to ensure ongoing compliance with the applicable legal requirements.

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, our domestic plants are subject to regulatory oversight by the Federal Energy Regulatory Commission, or FERC. This regulatory oversight includes the sale of 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 Energy Policy Act of 2005, or EPAct 2005, became law on August 8, 2005. EPAct 2005 contains a wide range of provisions addressing many aspects of the electric industry. For example, EPAct 2005 contains incentives to encourage the development of clean coal projects, and the Company is considering these incentives. Among the many provisions of EPAct 2005 is the repeal of the Public Utility Holding Company Act 1935, and the enactment of the Public Utility Holding Company Act 2005, which may impose additional books and records obligations on the Company. EPAct 2005 eliminates the statutory restrictions on ownership of qualifying facilities, and thus increases the realm of prospective purchasers of QF facilities. EPAct 2005 also gives FERC enhanced merger authority, but this enhanced authority is not expected to materially impact the Company's application to acquire Texas Genco or other acquisition activity. In addition, many provisions of EPAct 2005 require FERC and other agencies to engage in numerous rulemakings, and the Company is evaluating the impacts and opportunities that might result from these rulemakings. Included among these rulemakings, FERC has been authorized to oversee new Electric Reliability Organizations that will develop and enforce national and regional electric reliability standards. Also related to transmission reliability, EPAct 2005 contains numerous provisions regarding Transmission Infrastructure, Operation and Pricing. Finally, EPAct 2005 greatly expands the criminal and civil penalties for violations of the Federal Power Act with a specific emphasis on market manipulation and market transparency.

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, where several of our Connecticut plants are located, 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. On August 10, 2005, FERC issued an order delaying the implementation of a LICAP market from January 1, 2006 until October 1, 2006, at the earliest, and conducted oral argument on September 20, 2005. On October 7, 2005, participants in NEPOOL filed a joint motion with the Commission for the expedited appointment of a settlement judge and the commencement of settlement negotiations regarding the establishment of a LICAP market. On October 12, 2005, in response to a motion filed by the ISO for clarification of the FERC’s order of August 10, 2005 delaying implementation of the LICAP market, the Commission clarified that a separate energy zone for southwestern Connecticut does not have to be implemented until January 2007.

Our Devon, Middletown and Montville units are currently subject to Reliability Must Run, or RMR, agreements, that expire on December 31, 2005. On November 1, 2005, the Company made a filing at FERC to establish the rates, terms and conditions for 2006 RMR agreements applicable to some or all of the existing RMR units. The anticipated regulatory proceeding could have a material impact on the operation and revenues of the related assets.

On September 12, 2005, Richard Blumenthal, Attorney General for the State of Connecticut, the Connecticut Office of Consumer Counsel, the Connecticut Municipal Electric Energy Cooperative and the Connecticut Industrial Energy Consumers filed a formal complaint against ISO-NE pursuant to section 206 and 212 of the Federal Power Act, seeking to amend the ISO-NE’s Market Rule 1 to require all electric generation facilities not currently operating under an RMR agreement in Connecticut to be placed under cost-of-service rates. On October 20, 2005, the Company filed an answer requesting that the Commission dismiss the complaint. The Company’s Jet Power and Norwalk units are not currently operating under an RMR agreement.

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.

On October 6, 2005, Niagara Mohawk Power Corporation, NiMo, filed a complaint against NYISO and the New York State Reliability Council, or NYSRC, requesting that the Commission direct the NYSRC to modify its methodology for calculating the statewide Installed Reserve Margin. NiMo's complaint also alleges that the NYISO incorrectly calculates the Installed Capacity Requirement.

Mid Atlantic

On August 31, 2005, PJM Interconnection, L.L.C., or PJM filed in the above-captioned dockets a proposed Reliability Pricing Model, or RPM, that modifies the capacity obligations and market mechanisms within PJM. The primary features of the RPM are locational capacity markets, using a downward-sloping demand curve; a four-year-forward commitment of capacity resources; establishing separate obligations and auction procurement mechanisms for quick start and load following resources; allowing certain planned resources, transmission upgrades and demand resources to compete with existing generation resources to satisfy capacity requirements; and market power mitigation rules. On October 19, 2005, the Company filed an intervention and protest in response to the PJM RPM proposal.

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, or 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. FERC is expected 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 this proceeding will be addressed in a future order.

Western Region

The Cal ISO and the California Energy Commission, or CEC, projected 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 one year in advance by September 2005. Once market mitigation measures such as the FERC "must offer" order is eliminated and firm liquidated contracts are phased out entirely, 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. The capacity for El Segundo units 3 and 4 has been secured under a tolling agreement with a major load serving entity for the period May 2006 through April 2008. 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 has just issued their final resource adequacy order thus creating greater opportunities for merchant generators in California. Finally, the state signed new legislation in September 2005 (AB 1576), that codifies cost recovery for utilities when securing generating contracts from repowered generation facilities. This provides opportunities for the Western region, as NRG currently holds a permit for repowering up to 650 MW at the El Segundo facility and options for redevelopment at the Long Beach facility. Both facilities are positioned for possible long-term contracts as the market rules and structure fall into place in the near future.

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, which came into effect on July 1, 2005, are not intended to alter the fundamental design or operation of the market, but are designed to improve the regulatory framework.

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, conducted an investigation into the event which was released on October 13, 2005. NRG Flinders was deemed to have breached their Performance Standards under the National Electricity Code on three occasions during the events of March 14. As a result, fines totaling AU $0.3 million (US $0.2 million) were imposed on NRG Flinders by the National Electricity Tribunal on August 15, 2005, 50 percent of which were suspended subject to no further breaches occurring in the following 12 months.

RESULTS OF OPERATIONS

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

	For the three months ended September 30, 2005 (In thousands)						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
Energy revenue	$ 567,059	$ 100,845	$ 430	$ 8,588	$ 35,712	$ 26,278	$ 738,912
Capacity revenue	73,694	46,555	—	660	—	19,824	140,733
Alternative revenue	3	—	—	619	—	46,536	47,158
O & M fees	—	—	—	—	—	4,910	4,910
Hedging & risk management activity	(254,018)	(218)	—	(90)	12,454	371	(241,501)
Other revenue	51,806	27,404	1	447	7,790	(12,344)	75,104
Operating revenues	438,544	174,586	431	10,224	55,956	85,575	765,316
Cost of energy	322,616	139,275	312	8,893	24,432	41,801	537,329
Derivative cost of energy	4,650	1,807	—	—	—	—	6,457
Other operating expenses[1]	88,710	23,535	1,185	8,750	25,512	36,246	183,938
Depreciation and amortization	18,643	15,284	30	1,670	7,117	6,058	48,802
Operating income/(loss)	3,980	(5,290)	(1,097)	(9,088)	(1,105)	5,816	(6,784)
MWh sold[2]	5,291	2,734	4	61	1,438		
Cooling Degree Days, or CDDs[3]	1,251	1,626	568	679			
Heating Degree Days, or HDDs[3]	109	2	53	57			

	For the three months ended September 30, 2004 (In thousands)						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
Energy revenue	$ 224,716	$ 55,695	$ 4,168	$ 8,826	$ 33,640	$ 17,256	$ 344,301
Capacity revenue	76,311	46,921	—	30,736	—	20,408	174,376
Alternative revenue	13	—	—	239	—	40,885	41,137
O & M fees	—	—	—	24	—	4,724	4,748
Hedging & risk management activity	6,204	186	—	1,125	9,659	846	18,020
Other revenue	13,853	4,338	(755)	(2,069)	4,107	2,576	22,050
Operating revenues	321,097	107,140	3,413	38,881	47,406	86,695	604,632
Cost of energy	139,122	57,345	3,284	5,068	21,034	40,660	266,513
Derivative cost of energy	(2,098)	1	—	—	—		(2,097)
Other operating expenses [1]	77,998	16,772	940	16,509	19,691	37,566	169,476
Depreciation and amortization	18,190	15,658	197	5,005	5,179	6,831	51,060
Operating income/(loss)	87,772	16,612	(1,008)	(12,188)	1,503	(13,980)	78,711
MWh sold[2]	3,765	2,921	56	13	1,398		
Cooling Degree Days, or CDDs[3]	810	1,353	588	408			
Heating Degree Days, or HDDs[3]	167	3	54	121			

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

2 Includes MWhs sold for wholly owned subsidiaries only.

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

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

	For the nine months ended September 30, 2005						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
				(In thousands)			
Energy revenue	$ 1,080,307	$ 229,691	$ 566	$ 14,613	$ 103,812	$ 64,851	$ 1,493,840
Capacity revenue	211,372	137,390	—	4,924	—	61,947	415,633
Alternative revenue	348	—	—	1,713	—	139,844	141,905
O & M fees	—	—	—	—	—	14,049	14,049
Hedging & risk management revenue	(292,247)	(265)	—	(90)	40,553	1,516	(250,533)
Other revenue	86,900	33,845	15	(4,325)	17,514	(6,015)	127,934
Operating revenues	1,086,680	400,661	581	16,835	161,879	276,192	1,942,828
Cost of energy	666,661	277,334	692	15,356	71,414	131,058	1,162,515
Derivative cost of energy	3,326	1,747	—	—	—	—	5,073
Other operating expenses [1]	284,127	74,520	3,846	18,322	72,648	96,201	549,664
Depreciation and amortization	55,834	45,511	425	5,014	19,829	17,704	144,317
Operating income/(loss)	76,732	1,549	(4,382)	(21,857)	(2,012)	31,229	81,259
MWh sold[2]	12,640	7,398	6	93	4,168		
Cooling Degree Days, or CDDs[3]	1,585	2,563	719	940			
Heating Degree Days, or HDDs[3]	8,159	1,178	1,847	3,851			

	For the nine months ended September 30, 2004						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
				(In thousands)			
Energy revenue	$ 666,968	$ 155,483	$ 7,118	$ 14,090	$ 115,972	$ 92,708	$ 1,052,339
Capacity revenue	207,005	136,760	(3,709)	71,614	—	61,863	473,533
Alternative revenue	24	—	—	1,257	—	128,644	129,925
O & M fees	—	—	(2)	148	—	15,124	15,270
Hedging & risk management revenue	2,204	144	—	1,125	27,793	1,718	32,984
Other revenue	50,465	12,515	(2,387)	(6,782)	2,663	10,144	66,618
Operating revenues	926,666	304,902	1,020	81,452	146,428	310,201	1,770,669
Cost of energy	396,718	155,838	4,205	9,733	62,941	126,188	755,623
Derivative cost of energy	(461)	—	—	—	—	(4)	(465)
Other operating expenses [1]	246,214	50,763	3,678	33,553	59,179	99,612	492,999
Depreciation and amortization	54,101	47,192	602	18,915	17,190	20,603	158,603
Operating income/(loss)	229,631	48,027	(7,465)	(5,387)	7,118	38,989	310,913
MWh sold[2]	11,146	7,830	64	27	3,970		
Cooling Degree Days, or CDDs[3]	1,030	2,257	842	587			
Heating Degree Days, or HDDs[3]	8,115	1,274	1,695	3,932			

1 Other operating expenses include "Cost of majority-owned operations" and "General, administrative and development" expenses, excluding Cost of energy.

2 Includes MWhs sold for wholly owned subsidiaries only.

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

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

Highlights for the Three Months Ended September 30, 2005

This summer, one of the hottest in the last 100 years[1], saw electricity prices and spark spreads at much higher levels than the summer of 2004. As compared to the third quarter of 2004, on-peak electricity prices increased 67% to 94% in the various markets we operate, while gas and oil prices increased over 75% and 66% respectively, resulting in higher absolute electricity prices and spark and oil spreads when compared to last year[2]. With electricity prices increasing greater than our coal costs, our dark spreads have increased as well. Given the hot weather, total generation from our domestic assets increased for the quarter by 20% over the third quarter of 2004. These favorable market conditions had a positive impact on our revenues and margins, prior to any energy trading. However, our hedging and risk management activity, and mark-to-market transactions in particular, had the most profound effect on our results. Quarterly highlights include:

- For the three months ended September 30, 2005 and 2004 we incurred a net loss of $26.9 million, or $(0.39) per diluted EPS and a $54.2 million gain or $0.54 per diluted EPS, respectively
- Total CDDs were 54.4% higher in the Northeast and 20.2% higher in the South Central region for the current quarter versus the same period in 2004
- Extreme weather conditions, including Hurricanes Katrina and Rita, benefited our generation portfolio by increasing the sale price of power. However, this increase in power prices also drove the net unrealized mark-to-market losses of $171.2 primarily associated with financial electric sales in support of our Northeast assets
- The sale of emissions credits amounting to $25.4 million
- $172.4 million in net mark-to-market derivative losses associated with the forward electricity sales supporting our Northeast assets

Consolidated Results

Revenues from Majority-Owned Operations

Revenues from majority-owned operations were $765.3 million for the three months ended September 30, 2005 compared to $604.6 million for the three months ended September 30, 2004, an increase of $160.7 million. Revenues for the three months ended September 30, 2005 included $738.9 million of energy revenues compared to $344.3 million of energy revenues for the three months ended September 30, 2004. Of the $738.9 million, 89.5% were merchant revenues, which are non-contracted and non-capacity generation revenues. In the third quarter of 2004, only 66% of our energy revenues were merchant. The increase in energy revenues in 2005 versus 2004 was due to increased power prices and increased generation from our Northeast assets. As the heat and strong plant reliability pushed volumes upward, generation from our Northeast assets increased by 40.5%, led primarily by our New York City and oil-fired assets. The New York City assets increased generation by 92% as compared to the third quarter of 2004. Generation from our peaking oil-fired assets, which rarely ran in the third quarter of 2004 due to limited demand, increased by over 325%, from .3 million MWh to 1.3 million MWh.

Capacity revenues for the three months ended September 30, 2005 were $140.7 million compared to $174.4 million for the three months ended September 30, 2004, a decrease of $33.7 million. This decrease is due to the loss of $15.8 million in capacity revenues from the Kendall facility, which was sold in the fourth quarter of 2004 and the May 2005 expiration of a tolling contract at our Rockford plant, which resulted in a $14.3 million reduction of capacity revenues. Alternative revenues for the three months ended September 30, 2005 were $47.2 million compared to $41.1 million in the third quarter of 2004. Our Thermal operations were positively impacted by $3.6 million due to increased generation driven by the hot weather and an increase in contract rates.

Other revenues include emission credits revenues, natural gas sales, Fresh Start-related contract amortization, and expense recovery revenues. For the three months ended September 30, 2005, other revenues totaled $75.1 million as compared to $22.1 million for the three months ended September 30, 2004. The increase is due to the increase in emission credit revenues and gas sales revenues. We actively manage our excess emissions credit position and this quarter initiated the sale of surplus credits, which resulted in $25.4 million in revenues as compared to $0.2 million in the third quarter of 2004. Gas sales increased quarter over quarter due to a gas sale agreement entered into this summer. This agreement in conjunction with power purchase agreements were entered into to minimize our market purchases during peak months. Gas sales increased $26.7 million of which $23 million is due to the new tolling agreement. These increases were offset by $6.1 million of lower contract amortization and $5 million in lower expense recovery revenues.

Hedging and Risk Management Activity

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1 National Climate Data Center/NESDIS/NOAA June and August 2005 Regional Ranks.

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

	For the three months ended September 30, 2005						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
				(In thousands)			
Net gains/(losses) on settled positions, or financial revenues	$ (86,720)	$ (1,242)	$ —	$ (90)	$ 10,435	$ 371	$ (77,246)
Mark-to-market results:							
Reversal of previously recognized unrealized gains/(losses) on settled positions	447	24	—	—	—	—	471
Net unrealized gains/(losses) on open positions	(172,395)	(807)	—	—	2,019	—	(171,183)
Subtotal mark-to-market results	(171,948)	(783)	—	—	2,019	—	(170,712)
Total derivative gain/(loss)	$ (258,668)	$ (2,025)	$ —	$ (90)	$ 12,454	$ 371	$ (247,958)

Hedging and Risk Management Activity — The total derivative loss for the quarter was $248 million, comprised of $77.2 million in financial revenue losses and $170.7 million of mark-to-market losses. The $77.2 million loss of financial revenues represent the settled value for the quarter of all financial instruments including but not limited to financial swaps on power. Of the $170.7 million of losses associated with forward risk management activities, $171.2 million represents fair value changes of forward sales of electricity and fuel — $164.7 million associated with electricity sales and $6.4 million associated with cost of fuel — and the reversal of $0.5 million of mark-to-market losses which ultimately settled as financial revenues. These economic hedging activities primarily support our Northeast assets.

Since economic hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on energy revenues and costs of energy. The total derivative loss for the quarter was $248 million, comprised of $77.2 million in financial revenue losses and $170.7 million of mark-to-market losses. Over the course of 2005, we hedged much of the fourth quarter 2005 and calendar year 2006 Northeast generation. Since that time and during the third quarter 2005 in particular, the settled and forward prices of electricity rose, driven by the extreme weather conditions. While this increase in electricity prices benefited our generation portfolio versus last year with higher energy revenues, it is also the reason for the mark-to-market recognition of the forward sales and the settlement of financial transactions as losses.

Cost of Majority-Owned Operations

Cost of majority-owned operations for the three months ended September 30, 2005 was $668.4 million or 87% of revenues from majority-owned operations. Cost of majority-owned operations for the three months ended September 30, 2004 was $379.9 million or 63% of revenues from majority-owned operations. Cost of majority-owned operations consists of the cost of energy (primarily fuel costs), operating and maintenance costs, or O&M costs, and non-income based taxes. Cost of energy for the third quarter of 2005 was $543.8 versus $264.4 million for the third quarter of 2004, an increase of $279.4 million. Higher gas and oil fuel cost in our domestic operations were the primary drivers of the increased fuel costs, with gas prices 73% higher and oil prices 66% higher than third quarter last year. Our gas fuel cost increased by $98.5 million. Of this total, $22.9 million and $7.3 million was related to gas sales by our South Central and Northeast regions, respectively. The balance is primarily related to the $62.2 million in higher gas costs at our New York City plants, 48% of which was due to higher generation with the balance due to increased prices. Oil fuel cost increased by $84.4 million, 75% of the increase was due to higher generation and 25% was due to an increase in price. Coal costs increased by $26.7 million, 94% due to higher prices as generation from our coal-fired plants was stable from third quarter 2005 as compared to third quarter 2004. Additionally, purchased energy increased by $52.6 million, due to both the hot weather and increased gas prices. Our South Central region purchased $58.4 million in additional energy as increased contract load and the 100 MW around-the-clock sale to Entergy required the purchase of an additional 821,554 MWh, or 856% more purchased energy than third quarter 2004.

O&M costs for the third quarter 2005 totaled $109.7 million versus $107.5 million in the third quarter of 2004. O&M costs are largely driven by scheduled major maintenance, but during the key summer month season, little major maintenance is scheduled. Non-income taxes for the quarter totaled $15 million as compared to $7.7 million in 2004. The increase of $7.3 million is due to favorable true-ups from 2003 and 2004 property tax estimates recorded in our 2004 results.

Depreciation and Amortization

Our depreciation and amortization expense for the three months ended September 30, 2005 and 2004 was $48.8 million and $51.1 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 $3.3 million in depreciation and amortization expense in the third quarter of 2004.

General, Administrative and Development

Our general, administrative and development, or G&A, costs for the three months ended September 30, 2005 were $47.2 million compared to $54 million for the three months ended September 30, 2004. These amounts include corporate costs of $20.4 million, or 2.7% of operating revenues, for the third quarter of 2005, as compared to $30.5 million, or 5% of operating revenues, for the third 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. The decrease of $6.8 million in G&A cost is explained by lower consulting fees related to the 2002 Sarbanes-Oxley Act, lower negotiated insurance rates, and a bad debt allowance recognized during the third quarter of 2004 of $4.5 million for a note receivable held by a third party.

Corporate Relocation Charges

During the three months ended September 30, 2005, charges related to our corporate relocation activities were $1.7 million as compared to $5.7 million for the same period in 2004. This decrease in expense reflects the fact that the relocation expenditure for our corporate headquarters are nearly complete. The relocation plan will be completed by the end of 2005, and we expect to incur an additional $0.4 million during the fourth quarter.

Impairment charges

On an annual basis we evaluate the possible impairment of our assets, unless certain events occur which trigger an impairment analysis. During the three months ended September 30, 2005, we recorded $6 million of impairment charges related to the decision to auction an idle turbine based on estimated sales prices for similar turbines. For the three months ended September 2004, we recorded $40.5 million in asset impairments related primarily to the impairment to the realizable values as a result of our decision to sell Kendall and the Meriden turbine.

Equity in Earnings of Unconsolidated Affiliates

During the three months ended September 30, 2005, we recorded $29.1 million of equity earnings from our investments in unconsolidated affiliates as compared to $53.4 million for the three months ended September 30, 2004, a decrease of $24.3 million. Our equity earnings from WCP comprised $6.7 million for the third quarter of 2005, a decline from the $17.2 million in WCP equity earnings for the third quarter of 2004. This decrease was due to the expiration of the CDWR contract in December 2004. Additionally, equity earnings in 2004 included $14.6 million of Enfield earnings. We sold our Enfield investment on April 1, 2005.

Other equity investments included in the 2005 results are MIBRAG and Gladstone, comprising $8.9 million and $6.0 million, respectively. During the three months ended September 30, 2004, we recorded earnings of $3.4 million for MIBRAG and $2.1 million for Gladstone. MIBRAG's equity earnings for 2004 were negatively impacted by an outage at our Schkopau plant, resulting in lower coal sales at MIBRAG.

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

During the third quarter of 2005 we sold our option to repurchase a Kendall interest for a gain of $4.3 million as there was no further benefit in retaining an interest in Kendall. This compares to $13.5 million loss on the sale of equity method investments recognized in the third quarter of 2004. During the third quarter of 2004, we recorded losses associated with the sales of Commonwealth Atlantic Limited Partnership, or CALP, James River Power, LLC, and several NEO investments. The CALP and the NEO investments sales closed in 2004.

Other income, net

During the three months ended September 30, 2005 and 2004, we recorded $10.0 million and $5.5 million, respectively, of other income, net, an increase of $4.5 million. Other income includes interest income, gain or loss on foreign exchange, and other miscellaneous items. Of this increase, interest income contributed $5.1 million due to improved cash management.

Refinancing Expense

During the three months ended September 30, 2005, we recorded $19.0 million of refinancing expense associated with the repurchase of $229 million of our Second Priority Notes.

Interest expense

Interest expense for the three months ended September 30, 2005 was $45.8 million as compared to $66.1 million, for the three months ended September 30, 2004, a decrease of $20.3 million. Interest expense declined, in part, due to the sale of Kendall in the fourth quarter of 2004. Kendall incurred $6.8 million of interest expense in the third quarter of 2004. Additionally, in December 2004 we refinanced our Senior Credit Facility and lowered our interest rate by 212.5 basis points, and since December 2004 we have redeemed a total of $645 million of our Second Priority Notes. Together, these transactions reduced interest expense by approximately $12.8 million.

Income Tax Expense

Income tax expense was $8.5 million and $14.6 million for the three months ended September 30, 2005 and 2004, respectively. The effective tax rate was (30.1)% and 25.1% for the three months ended September 30, 2005 and 2004, respectively. The effective income tax rate for the three months ended September 30, 2004 differs from the U.S. statutory rate of 35% due to lower tax rates for income derived in foreign jurisdictions. For the three months ended September 30, 2005, our effective tax rate differed from the U.S. statutory rate due to taxable income derived in foreign jurisdictions at a lower tax rate. In addition, our overall effective tax rate was affected by the taxable dividend received pursuant to the American Jobs Creation Act of 2004 combined with an increase in the deferred tax valuation allowance. Also see our tax rate reconciliation disclosure in Note 11, *Income Taxes*, to the Condensed Consolidated Financial Statements.

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

During the three months ended September 30, 2005 and 2004, we recorded income from discontinued operations, net of income taxes, of $9.9 million and $10.9 million, respectively, as we continued to divest our non-core assets. Discontinued operations for the three months ended September 30, 2005 is comprised of our Northbrook New York and Northbrook Energy operations and includes a $12.3 million pre-tax gain on the disposition of these activities. In addition to the Northbrook operations, during the three months ended September 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). With the exception of Northbrook New York and Northbrook Energy, all discontinued operations were sold prior to December 31, 2004.

Regional Discussion

Northeast Region Results

Operating Income

For the three months ended September 30, 2005, operating income for the Northeast region was $4.0 million, as compared to $87.8 million for the three months ended September 30, 2004, a decrease of $83.8 million. This decrease was driven by the $172.4 million unrealized mark-to-market losses related to forward sales of electricity supporting our Northeast assets. During the third quarter of 2004, the Northeast realized $4.9 million in mark-to-market losses. Excluding these mark-to-market losses, the Northeast operating income totaled $176.4 as compared to $92.7 million in the third quarter of 2004, an increase of $83.4 million. This increase was largely driven by the higher spark and dark spreads and increased generation from our Northeast assets. Total generation from our Northeast assets increased 40.5% versus the third quarter of 2004. Power prices in the Northeast region increased 67% to 94% in the various markets we operate. With gas prices 75.7% higher and oil prices 66% higher this quarter versus third quarter 2004, spark spreads and oil spreads widened. With few outages scheduled during the third quarter, O&M expenses in the Northeast region were relatively stable as compared to the third quarter of 2004. Non-income related taxes increased by $8.2 million due to the recognition of a larger amount of property tax credits recognized in 2004.

Revenues

Revenues from our Northeast region totaled $438.5 million for the three months ended September 30, 2005 compared to $321.1 million for the three months ended September 30, 2004, an increase of $117.4 million. Revenues for the three months ended September 30, 2005 included $567.1 million in energy revenues compared to $224.7 million for the three months ended September 30, 2004. This favorable increase of $342.4 million is due to a steep increase in power prices and a 40.5% increase in generation. Due to extreme weather conditions in 2005, combined with the increase in gas and power prices, financial results from our peaking plants improved quarter over quarter. With an increase of 441 CDDs for the Northeast region, or 54.4% for the third quarter of 2005 compared to 2004, and a 92% increase in generation from our

New York City assets, energy revenues from these plants increased $97.7 million, and an additional $10.7 million was recognized due to settlements from NYISO. Our oil-fired assets generated 327.7% more MWh this quarter versus the third quarter of 2004, realizing a $123.1 million increase in energy revenues. Generation from our Northeast base-load coal-fired plants also increased by 7.7%. Energy revenues from these assets increased $119.6 million.

Other revenues increased by $37.9 million and includes emission credits sales, natural gas sales, Fresh Start-related contract amortization, and expense recovery revenues. The Northeast recorded $40.6 million in revenues from the sale of emission credits. The $40.6 million represents $25.2 million in external sales and $15.4 million in intercompany sales to our Commercial Operations group. No emission credit revenues were recorded in the comparable period for 2004.

Hedging and Risk Management Activity - The Northeast's total derivative loss for the quarter was $258.7 million, comprised of $86.7 million in financial revenue losses and $171.9 million of mark-to-market losses. The $86.7 million loss of financial revenues represent the settled value for the quarter of all financial instruments including but not limited to financial swaps on power. Of the $171.9 million of losses associated with forward risk management activities, $172.4 million represents fair value of forward sales of electricity and fuel — $167.7 million associated with electricity sales and $4.7 million associated with cost of fuel — and the reversal of $0.5 million of mark-to-market losses which ultimately settled as financial revenues.

Since economic hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on energy revenues and costs of energy. Over the course of 2005, we hedged much of the fourth quarter 2005 and calendar year 2006 Northeast generation. Since that time and during the third quarter 2005 in particular, the settled and forward prices of electricity rose, driven by the extreme weather conditions. While this increase in electricity prices benefited our generation portfolio versus last year with higher energy revenues, it is also the reason for the mark-to-market recognition of the forward sales and the settlement of positions as losses.

Cost of energy

Cost of energy in the Northeast was $327.2 million or 75% of the Northeast revenue as compared to $137 million or 43% of the Northeast revenue in 2004, an increase of $190.2 million. Oil costs in our Northeast region increased by $82.9 million, with approximately 75% of the increase due to increased generation. Gas costs increased by $71.7 million over the third quarter of 2004. Of this total, $31 million was due to increased generation and $28.9 million was due to increased prices at our New York City assets, with the remainder associated with increased gas sales. Coal costs in our Northeast region increased by $26 million, 80% of the increase due to higher prices. The increase in coal prices is related to new coal and rail contracts which became effective in April 2005, as well as the non-PRB coal we use for blending purposes. We have increased our percentage blend of Western coal during the quarter versus the same period last year.

Other operating expenses

Other operating expenses consists of O&M, non-income tax expense, and G&A expenses which total $88.7 million for the third quarter of 2005 as compared to $78 million for the third quarter of 2004, an increase of $10.7 million. Other non-income based taxes increased by $8.2 million due to lower property tax credits in 2005. G&A expenses for the Northeast region include administrative regional office costs, insurance and corporate allocations which increased by $4.8 million. 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.

South Central Region Results

Operating Income

For the period ending September 30, 2005, the South Central region incurred an operating loss of $5.3 million, as compared to $16.6 million in operating income for the period ended September 30, 2004, a decrease of $21.9 million. This quarter, co-op and long term customer load demand was strong with 2.7 MWh delivered to such customers, an increase of 9.5%, with August setting a record high for summer load. Consequently, high customer demand required South Central to purchase energy to meet its load requirements. With on-peak power prices 85.7% higher this quarter versus the third quarter of 2004, South Central recorded $58.4 million more in purchased energy costs. Additionally, high customer load demand limited South Central's ability to sell into the merchant market where prices are generally more favorable than our contracted energy prices. Actual generation from the South Central facilities was down by 6.4%. The quarter on quarter results are also reflective of the impact of third quarter 2004's mild weather, which generally provides favorable financial results for South Central. Higher O&M and G&A costs also contributed to the operating loss this quarter.

Revenues

Revenues from our South Central region were $174.6 million for the three months ended September 30, 2005 compared to $107.1 million for the three months ended September 30, 2004, an increase of $67.5 million. Revenues for the three months ended September 30, 2005 included $100.8 million in energy revenues, of which 62% were contracted. This compares to $55.7 million of energy revenues for the three months ended September 30, 2004; 83.4% of which were contracted. New and higher contract rates became effective on January 1, 2005 and together with increased demand from contracted customers, increased contracted energy revenues by $15.2 million. Merchant revenues increased by $33.1 million, as merchant generation increased by 83.8% due to the hot weather over the third quarter of 2004. Other revenues include coal sales and Fresh Start-related contract amortization. For the three months ended September 30, 2005, other revenues totaled $27.4 million compared to $4.3 million for the three months ended September 30, 2004, an increase of $22.9 million due to a new gas sale agreement entered into in July 2005.

Cost of Energy

Total cost of energy in South Central was $141.1 million as compared to $57.3 million in 2004, an increase of $83.7 million. Of this increase, $23 million relates to the cost of gas purchased to resell to a third party under a tolling agreement entered into in July 2005, and $58.4 million is for purchased energy costs because of higher load from the Region's long-term contracts, a 100 MW around-the-clock sale to Entergy and increased pricing. As a result of the warm weather and the impact of Hurricanes Katrina and Rita, the average purchased energy price increased $13.21 per MWh. Purchases increased 856% from 96 thousand MWh in the third quarter of 2004 to 917 thousand MWh in 2005.

Other Operating Expenses

Other operating expenses were $23.5 million and $16.8 million for September 30, 2005 and 2004, respectively. O&M for our South Central region was $11.7 million for the third quarter 2005 as compared to $9.4 million in the third quarter 2004, with the increase related to higher maintenance costs. Additionally, in the third quarter of 2005, South Central recorded to a $1.9 million in bad debt allowance associated with a receivable with Entergy New Orleans, which filed for bankruptcy following Hurricanes Katrina and Rita. The balance of the increase is due to the new NRG allocations methodology as discussed in Note 10, *Segment Reporting,* to the Condensed Consolidated Financial Statements.

Western Region Results

For the period ending September 30, 2005, the Western region incurred an operating loss of $1.1 million, as compared to a $1.0 million loss for the period ended September 30, 2004. The negative variance in revenues and 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 September 30, 2005, the Other North America region realized an operating loss of $9.1 million on revenues of $10.2 million, as compared to an operating loss of $12.2 million and revenues of $38.9 million for the three months ended September 30, 2004. This decrease of $3.1 million in operating losses is due to the asset impairment of Kendall taken in the third quarter of 2004 and the subsequent sale of Kendall in late 2004, and the expiration of a tolling contract at our Rockford facility in May 2005. Kendall had operating income of $11.4 million and revenues of $25.5 million in the third quarter of 2004. Rockford had an operating loss this quarter of $0.9 million on revenues of $5.6 million as compared to operating income of $10 million on revenues of $12.9 million in the third quarter of 2004.

Australia Region Results

Operating Income

For the period ending September 30, 2005, the Australia region realized an operating loss was $1.1 million, as compared to $1.5 million operating income for the period ended September 30, 2004. Total generation increased by 2.9% due to the full commercialization of Playford and an outage in the third quarter of 2004. This increase was offset by higher maintenance cost at the Playford station, and lower pool prices this quarter versus the third quarter of 2004.

Revenues

Revenues from our Australia region totaled $56 million for the three months ended September 30, 2005 compared to $47.4 million for the three months ended September 30, 2004, an increase of $8.6 million. Revenues for the three months ended September 30, 2005 included $35.7 million in energy revenues compared to $33.6 million of energy revenues for the three months ended September 30, 2004. This increase was the result of higher generation due to the full commercialization of our Playford station in late 2004, however this was offset by 7% lower pool prices during the third quarter of 2005 compared to 2004. Other revenues include natural gas sales and Fresh Start-related contract amortization. Other revenues increased this quarter over third quarter 2004 from $4.1 million to $7.8 million. This increase is due to a reduction of $2.8 million in Fresh Start-related contract amortization in 2005 versus 2004.

Cost of Energy

Cost of energy for our Australia region for the three months ended September 30, 2005 was $24.4 million as compared to $21 million for the three months ended September 30, 2004. The $3.4 million increase in cost of energy is due to the increase in generation associated with our Playford facility, which was not fully operational in the third quarter of 2004.

Other Operating Expenses

Other operating expenses for Australia for the three months ended September 30, 2005 and 2004 were $25.5 million and $19.7 million, respectively. The increase is due to higher maintenance at the Playford plant as it became operational at the end of 2004, and the new NRG allocations methodology as discussed in Note 10, *Segment Reporting*, to the Condensed Consolidated Financial Statements.

For the nine months ended September 30, 2005 compared to the nine months ended September 30, 2004

Consolidated Results

Highlights for the nine months ended September 30, 2005

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[1]. This summer, however, was one of the hottest in the last 100 years[2], with electricity prices and spark spreads rising to much higher levels than the summer of 2004. As compared to the nine months ended September 30, 2004, on-peak electricity prices increased 32% to 37% in the various markets we operate, whereas our total coal costs, which are largely contracted, increased only 12% increasing our dark spreads. Gas and oil prices increased over 33.5% and 42.2%, resulting in higher spark spreads, but compressed oil margins as compared to the same period last year[3]. Total generation increased over the nine months ended September 30, 2004 by 5.5%. Other notable year-to-date events include:

- For the nine months ended September 30, 2005 and 2004, net income was $19.6 million, or $0.07 per diluted EPS and $167.5 million or $1.67 per diluted EPS, respectively.
- The sale of emission credits totaling $27.8 million
- Extreme weather conditions, including Hurricanes Katrina and Rita, benefited our generation portfolio by increasing the sale price of power. However, this increase in power prices also drove the net unrealized mark-to-market losses of $200.3 primarily associated with financial electric sales in support of our Northeast assets
- Planned and forced outages at our Huntley, Indian River and Big Cajun II plants during the second quarter of 2005 negatively impacted our generation
- The repurchase of $645 million par value of our Second Priority Notes, resulting in $44 million refinancing charges
- Receipt of $105.2 million in net proceeds for the sale of Enfield, our Northbrook assets, and Kendall interest

Revenues from Majority-Owned Operations

Revenues from majority-owned operations were $1,942.8 million for the nine months ended September 30, 2005 compared to $1,770.7 million for the nine months ended September 30, 2004, an increase of $172.1 million. Revenues for the nine months ended September 30, 2005 included $1,493.8 million of energy revenues compared to $1,052.3 million of energy revenues for the nine months ended September 30, 2004, an increase of $441.5 million. Of the $1,493.8 million, 86.8% are merchant revenues; in the third quarter of 2004, 68.7% of our energy revenues were merchant. The increase in energy revenues versus 2004 was driven by both increased prices and the increased merchant generation from our Northeast assets. With New York City generation 96% higher than the third quarter of 2004, energy revenue from our New York City assets increased by $159.4 million, $10.7 million due to settlements from NYISO. Of the remaining $148.7 million, approximately 55% was due to higher volumes generated. Energy revenues from our oil-fired assets rose by $162.9 million, 87% due to higher volumes; the generation from these assets increased by 129% for the nine months ended September 30, 2005 as compared to the same period in 2004. The Northeast coal assets' energy revenues increased by $91 million, all due to increased power prices, as generation from our Northeast coal assets decreased 8.2% for the nine

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

2 National Climate Data Center/NESDIS/NOAA June and August 2005 Regional Ranks.

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

months ended September 30, 2005 as compared to the same period in 2004. This decrease was due to both planned and unplanned outages at Huntley, Indian River, and Big Cajun II during the second quarter. 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 nine months ended September 30, 2005 were $415.6 million compared to $473.5 million for the nine months ended September 30, 2004, a reduction of $57.9 million. Capacity revenues were unfavorable versus last year due to the loss of capacity revenues of $45.9 million from the Kendall facility, which was sold in the fourth quarter of 2004, and the expiration of the Rockford tolling agreement in May 2005 which reduced quarter-on-quarter results by $20.6 million. Capacity revenues from our western New York plants decreased by $9.3 million due to 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 for the nine months ended September 30, 2005 were $141.9 million and $129.9 million, respectively. Increased generation due to the hotter weather and an increase in contract rates from our Thermal and Resource Recovery operations positively impacted the alternative revenues results.

Other revenues include emission credit sales, natural gas sales, Fresh Start-related contract amortization, and expense recovery revenues. For the nine months ended September 30, 2005, other revenues totaled a $127.9 million compared to $66.6 million of other revenues for the nine months ended September 30, 2004. We are actively managing our surplus emission credit position and initiated sales this quarter, recording $27.8 million in sales as compared to $3.6 million for the nine months ended 2004. The increase in other revenues was also attributed to $33.6 million in higher gas sales. The increase in gas sales is related to a new gas sale agreement entered into in the third quarter of 2005 by the South Central region. We entered into this agreement in conjunction with power purchase agreements were to minimize our market purchases during peak months. Lower contract amortization of $22.8 million is related to contracts rolling off over the course of time. Finally, during the nine months that ended September 30, 2005, lower expense recovery revenues were $19.5 million lower versus the comparable period in 2004. Expense recovery revenues is associated with our Connecticut RMR agreements and we reached our maximum payment under that agreement during the first quarter of 2005.

Hedging and Risk Management Activity

	For the nine months ended September 30, 2005						
	Northeast	South Central	Western	Other North America	Australia	All Other	Total
				(In thousands)			
Net gains/(losses) on settled positions, or financial revenues	$ (39,347)	$ (1,317)	$ —	$ (90)	$ 34,569	$ 1,516	$ (4,669)
Mark-to-market results							
Reversal of previously recognized unrealized gains/(losses) on settled positions	(50,420)	(257)	—	—	—	—	(50,677)
Net unrealized gains/(losses) on open positions	(205,806)	(438)	—	—	5,984	—	(200,260)
Subtotal mark-to-market results	(256,226)	(695)	—	—	5,984	—	(250,937)
Total derivative gain/(loss)	$ (295,573)	$ (2,012)	$ —	$ (90)	$ 40,553	$ 1,516	$ (255,606)

Hedging and Risk Management Activity - The total derivative loss for the quarter was $255.6 million, comprised of $4.7 million in financial revenue losses and $250.9 million of mark-to-market losses. The $4.7 million loss of financial revenues represent the settled value for the quarter of all financial instruments including but not limited to financial swaps on power. Of the $250.9 million of mark-to-market losses, $200.3 million represents the change in fair value of forward sales of electricity and fuel — $195.2 million losses associated with electricity sales and $5.1 million gain associated with cost of fuel — and the reversal of $50.7 million of mark-to-market gains which ultimately settled as financial revenues. These economic hedging activities primarily support our Northeast assets.

Since hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on energy revenues and costs of energy. In the fourth quarter of 2004 and over the course of 2005, we hedged much of our calendar year 2005 and 2006 Northeast generation. Since that time and during the third quarter 2005 in particular, the settled and forward prices of electricity rose, driven by the extreme weather conditions this summer. While this increase in electricity prices benefited our generation portfolio versus last year with higher energy revenues, it is also the reason for the mark-to-market recognition of the forward sales and the settlement of positions as losses.

Cost of Majority-Owned Operations

Cost of majority-owned operations for the nine months ended September 30, 2005 was $1,555.7 million or 80% of revenues. Cost of majority-owned operations for the nine months ended September 30, 2004 was $1,112.5 million or 62.8% of revenues from majority-owned operations. The increase over last year is primarily due to the cost of energy, which increased by $406.9 million, from $755.6 million for the period ended September 30, 2004 to $1,162.5 million for the same period in 2005. The increase in the cost of energy was driven by both higher price and generation in the Northeast region, higher gas sales in New York City, and higher purchased energy and gas sales in the South Central region. Total gas costs increased by $145.9 million, $112.1 million in the New York City assets alone. Of the increase from the New York City assets, $8.7 million was due to increased gas purchases for resale, with the 67% of the balance due to increased generation. South Central region gas costs increased by $24.2 million for the nine months that ended September 30, 2005 of which $23 million is due to physical gas purchases related to a new tolling agreement entered into in July 2005. Total oil costs for the company increased by $131.4 million, 65% due to increased generation from our oil-fired assets. Total coal costs increased by $43.2 million, $39.7 from our domestic generation assets. The increase at our domestic coal-fired assets is solely due to price increases, as overall generation from our coal-fired assets decreased for the nine months ended September 30, 2005 by 7% as compared to the same period in 2004 due to the planned and forced outages at our Huntley, Indian River and Big Cajun II facilities. The increase in coal prices is related to new coal and rail contracts which became effective in April 2005, as well the any non-PRB coal we use for blending purposes. We have increased our percentage blend of Western coal over the year as compared to the same period last year. This had the effect of mitigating the increase in non-PRB coal and coal transportation costs as PRB, or low sulfur coal prices were less volatile. Total purchased energy increased by $80.3 million, of which $90.5 million is due to increases at our South Central region. Higher long-term contract load demand due to the extreme weather, a 100 MW around-the-clock sale to Entergy, and the forced outages during the second quarter, required South Central to purchase energy to meet its contract load obligations.

Other Operating Expenses for the first nine months of 2005 totaled $388.2 million versus $357.3 million in the comparable period of 2004, an increase of $30.9 million. 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 nine months ended September 30, 2005 and 2004 was $144.3 million and $158.6 million, respectively. The decrease in depreciation and amortization from 2005 to 2004 is due to the 2004 sale of our Kendall plant, which contributed $13.7 million in depreciation and amortization expense in the first nine months of 2004.

General, Administrative and Development

Our G&A cost for the nine months ended September 30, 2005 were $149.6 million compared to $135.7 million for the nine months ended September 30, 2004, an increase of $13.9 million. Corporate costs represent $71.6 million or 3.7% of revenues and $70.1 million or 4% of revenues for the nine months ended September 30, 2005 and 2004, respectively. G&A costs have been adversely impacted by $6.3 million of increased insurance expense and increased consulting costs related to Sarbanes Oxley compliance for our 2004 year-end audit.

Corporate Relocation Charges

During the nine months ended September 30, 2005, charges related to our corporate relocation activities were $5.7 million as compared to $12.5 million for the same period in 2004. Included in this year's charges is $3.4 million related to the lease abandonment charges associated with our former Minneapolis office with the remainder related to the relocation, recruitment and transition costs. This decrease in expense reflects the fact that the relocation expenditure for our corporate headquarters are nearly complete. The relocation plan will be completed by the end of 2005, and we expect to incur an additional $0.4 million.

Equity in Earnings of Unconsolidated Affiliates

During the nine months ended September 30, 2005, equity earnings from our investments in unconsolidated affiliates were $82.5 million compared to $117.2 million for the nine months ended September 30, 2004, a decrease of $34.7 million. Our earnings in WCP accounted for $15.2 million and $45.1 million for the nine months ended September 30, 2005 and 2004, respectively. The decrease in WCP's equity earnings is due to the expiration of the CDWR contract in December 2004. Enfield's equity earnings are $10.6 million lower for the nine months ended September 30 2005 as compared to the same period in 2004 since Enfield was sold on April 1, 2005. For the nine months ended September 30, 2005 results for Enfield include approximately $11.9 million of unrealized gains associated with mark-to-market increases in the fair value of energy-related derivative instruments, as compared to $23 million of unrealized gain for the same period of 2004.

Other equity investments included in the 2005 results include MIBRAG and Gladstone which comprised $16.8 million and $17.7 million for the period ended September 30, 2005, respectively. For the comparable period in 2004, MIBRAG and Gladstone earned $14.2 million and $8.8 million, respectively.

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

During the nine months ended September 30, 2005, we recorded $15.9 million in gains on sales of equity earnings as we continued to divest of non-core assets. On April 1, 2005, we sold our 25% interest in Enfield, resulting 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. Additionally, during the nine months ended September 30, 2005, we sold our interest in Kendall for $5 million in net pre-tax proceeds and a pre-tax gain of $4.3 million. During the nine months ended September 30, 2004, we sold our Loy Yang investment which resulted in a $1.3 million loss, our interest in Commonwealth Atlantic Limited Partnership for a $3.7 million loss, and several NEO investments for $3.8 million loss. These losses were offset by a $0.7 million gain associated with the sale of Calpine Cogeneration. Additionally, during 2004, we wrote down our investment in James River LLC by $6 million since an impairment was necessary pending a prospective sale of our investment.

Other income, net

Other income had a net increase of $26.1 million during the nine months ended September 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 $18.3 million of higher interest income related to more efficient management of higher average cash balances.

Refinancing expense

Refinancing expenses for the nine months ended September 30, 2005 and 2004 were $44 million and $30.4 million, respectively. In the first nine months of 2005, in order to utilize our cash and reduce interest expense, we redeemed and purchased a total of $645 million of our Second Priority Notes. As a result of the redemption and purchases, we incurred $53.8 million in premiums and write-offs of deferred financing costs. Additionally, the Australia region refinanced their project debt for better terms, resulting in the write-off of $9.8 million of debt premium. During the nine months ended September 30, 2004, we refinanced certain amounts of our term loans with additional corporate level high yield notes for better terms, 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 nine months ended September 30, 2005 was $150.6 million as compared to $193.5 million for the nine months ended September 30, 2004, a reduction of $42.9 million. Interest expense was favorably impacted by the sale of Kendall in the fourth quarter of 2004 as Kendall incurred $19.9 million of interest expense in the nine months ended September 30, 2004. Additionally, the 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 and an additional $229 million in the third quarter of 2005 reduced interest expense on our corporate debt by approximately $33.6 million.

Income Tax Expense

Income tax expense was $21.2 million and $65.1 million for the nine months ended September 30, 2005 and 2004, respectively. The overall effective tax rate was 75.2% and 31.4% for the nine months ended September 30, 2005 and 2004, respectively. The effective income tax rate for the nine months ended September 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 13.1% and 11.8%, respectively, on foreign income. Our 2005 domestic income tax expense increased our overall effective tax rate due to our gain on the sale of Enfield, the taxable dividend received pursuant to the American Jobs Creation Act of 2004, and the recording of a valuation allowance. Also see our tax rate reconciliation disclosure in Note 11, *Income Taxes*, to the Condensed Consolidated Financial Statements.

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 adjustment 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

During the nine months ended September 30, 2005 and 2004, we recorded a gain from discontinued operations of $12.6 million and $25.3 million, respectively, as we continued to divest our non-core assets. Discontinued operations for the nine months ended September 30, 2005 consist of Northbrook New York and Northbrook Energy assets and various expenses related to NRG McClain to effect its liquidation. During the nine months ended September 30, 2004, discontinued operations consisted of the results of the two Northbrook entities, 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). With the exception of Northbrook New York and Northbrook Energy, all discontinued operations were sold prior to December 31, 2004.

Regional Discussion

Northeast Region Results

Operating Income

For the nine months ended September 30, 2005, operating income for the Northeast region was $76.7 million, as compared to $229.6 million for the same period in 2004, a decrease of $152.9 million. The period began with mild temperatures for the winter months and extreme weather conditions during the summer. This led to an increase in electricity prices and spark spreads rising to much higher levels than the summer of 2004. As compared to the nine months ended September 30, 2004, on-peak electricity prices increased 32% to 37% in the various markets we operate, while gas and oil prices increased over 33.5% and 42.2%, resulting in higher absolute electricity prices and spark spreads, but compressed oil margins as compared to the same period last year.[1] The Northeast's New York City assets benefited from the increased spark spreads as they nearly doubled their generation output versus last year, from 0.8 million MWh to 1.5 million MWh. Generation from our Northeast oil-fired assets increased by 129.4%, but oil margins decreased by 23% versus the first nine months of 2004, as our cost per MWh increased by 30% in comparison to the same period in 2004.

Revenues

Revenues from our Northeast region totaled $1,086.7 million for the nine months ended September 30, 2005 compared to $926.7 million for the nine months ended September 30, 2004, an increase of $160 million. Revenues for the nine months ended September 30, 2005 included $1,080.3 million in energy revenues compared to $667 million for the same period in 2004. Of this $413.3 million increase, $159.4 million can be attributed to our New York City assets. Due to outages of local competitors and extreme heat this summer, our New York City assets' generation increased by 96% for the nine months ended September 30, 2005 as compared to 2004. The increased generation accounted for 55% of the increase in energy revenues and an additional $10.7 million was recognized for NYISO settlements in 2005. Our oil-fired assets earned $162.9 million more in energy revenues, and generated 129% this period as compared to the nine months ended September 30, 2004; 87% of the increased energy revenues were due to increased generation. Our coal assets recorded higher energy revenues of $159.7 million due to higher power prices as generation from our coal assets decreased for the nine months ended September 30, 2005.

Capacity revenues for the nine months ended September 30, 2005 were $211.4 million compared to $207 million for the nine months ended September 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 western New York were negatively impacted by the addition of new capacity supply and increased imports into the state.

Other revenues include emission credit sales, natural gas sales, Fresh Start-related contract amortization, and expense recovery revenues and totaled $86.9 million for the nine months ended September 30, 2005 as compared to $50.4 million the same period in 2004, an increase of $36.5 million. This increase is related to the additional $41.7 million in emission credit sales to both external parties and inter-company sales. In addition, other revenues increased from $8.1 million in higher gas sales, and $6.4 million in lower contract amortization as the intangible balances decrease over time. Other revenues were adversely impacted by $19.5 million in

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

lower expense recovery revenues related to the Connecticut RMR agreement. Expense recovery revenues is associated with our Connecticut RMR agreements and we have reached our maximum payment under that agreement during the first quarter of 2005.

Hedging and Risk Management Activity – The total derivative loss for the quarter was $295.6 million, comprised of $39.3 million in financial revenue losses and $256.2 million of mark-to-market losses. The $39.3 million loss of financial revenues represent the settled value for the quarter of all financial instruments including by not limited to financial swaps and options on power. Of the $256.2 million of mark-to-market losses, $205.8 million represents fair value of forward sales of electricity and fuel — $202.5 million losses associated with electricity sales and $3.3 million gain associated with cost of fuel – and $50.4 million of mark-to-market losses which ultimately settled as financial revenues. These hedging activities primarily support our Northeast assets.

Since hedging activities are intended to mitigate the risk of commodity price movements on revenues and cost of energy sold, the changes in such results should not be viewed in isolation, but rather taken together with the effects of pricing and cost changes on energy revenues and costs of energy. In the fourth quarter of 2004 and over the course of 2005, we hedged much of our calendar year 2005 and 2006 Northeast generation. Since that time and during the third quarter 2005 in particular, the settled and forward prices of electricity rose, driven by the extreme weather conditions this summer. While this increase in electricity prices benefited our generation portfolio versus last year with higher energy revenues, it is also the reason for the mark-to-market recognition of the forward sales and the settlement of positions as losses.

Cost of energy

Cost of energy increased by $273.7 million for our Northeast region for the nine months ended September 30, 2005 compared to the same period in 2004. Oil fuel costs in our Northeast region increased by $132.4 million, where 65% of the increase was due to increased generation. The Northeast's gas fuel costs increased by $112.6 million. Higher generation and gas sales from our New York City assets drove the $112.6 million increase by $103.9 million and $8.7 million, respectively. Of the $103.9 million increase, 67% was due to higher generation from our New York assets. Coal costs increased by $35.1 million, due to increased prices, as our coal-fired generation in the Northeast decreased for the first nine months of 2005 as compared to 2004, with outages at our western New York and Indian River facilities during the second quarter.

Other Operating Expenses

Other operating costs for our Northeast region increased by $37.9 million for the nine months ended September 30, 2005 compared to the same period in 2004. Major maintenance increased by $12.3 million as the low-sulfur conversion projects continue at our Western New York plants and began at our Indian River plant this year and 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, which increased by $21.5 million in 2005 compared to 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.

South Central Region Results

Operating Income

For the nine months ended September 30, 2005, the South Central region realized operating income of $1.5 million, as compared to $48 million for the nine months ended September 30, 2004. During the first nine months of the 2005, our Big Cajun II facility experienced several forced outages. Generation for the first nine months of 2005 decreased by 5.5% from 7.8 to 7.4 million MWh versus the same period in 2004, with 0.43 million MWh more lost to forced outages. These outages required the purchase of $90.5 million in additional energy to meet its contract load-following obligation in the merchant market at costs higher than our coal-based generating assets. In addition, during the first nine months of 2005, South Central had two planned outages versus one major outage during the first nine months of 2004, which increased major maintenance by $9 million as compared to the nine months ended September 30, 2004.

Revenues

Revenues from our South Central region were $400.7 million for the nine months ended September 30, 2005 compared to $304.9 million for the same period in 2004, an increase of $95.8 million. Revenues for the nine months ended September 30, 2005 included $229.7 million in energy revenues, of which 66% were contracted. This compares to $155.5 million of energy revenues for the nine months ended September 30, 2004, 78% of which were contracted. This increase of $74.2 million in energy revenues was due to increased merchant energy sales following higher power prices, favorable weather, and nuclear plant outages in the region. Other revenues include physical gas sales and Fresh Start-related contract amortization. For the nine months ended September 30, 2005, other revenues totaled $33.8 million compared to $12.5 million for the nine months ended September 30, 2004, with the increase due to $22.9 million increase in physical gas sales related to a new gas sale agreement entered into in July 2005. We entered into this agreement in conjunction with power purchase agreements to minimize our market purchases during peak months.

Cost of Energy

South Central's cost of energy increased by $123.2 million for the nine months ended September 30, 2005 compared to the same period in 2004. Of this amount, $90.5 million is due to higher purchased energy costs as compared to the nine months ended September 30, 2004. Over the first nine months of 2005, our Big Cajun II facility experienced a number of forced outages, encountered high demand from the Region's long-term contracts, and entered into 100 MW around-the-clock sale to Entergy, all of which required the purchase of energy to meet contract load obligations. Purchased energy per MWh increased by 1.4 million MWh or 856% versus the same period in 2004. Additionally, due to the extreme weather conditions and increasing gas prices, the average purchased energy price increased $11.82 per MWh for the nine months ended September 2005 as compared to the same period in 2004.

Other Operating Expenses

Other operating expenses increased by $23.8 million for the nine months ended September 30, 2005 compared to the same period in 2004, with $9 million of the increase related to increased major maintenance as our Big Cajun II facility experienced a number of forced outages, and $13.5 million related to regional office and the new NRG allocations methodology discussed in Note 10, *Segment Reporting*, to the Condensed Consolidated Financial Statements.

Western Region Results

For the nine months ended September 30, 2005, the Western region realized an operating loss of $4.4 million, as compared to an operating loss of $7.5 million for the nine months ended September 30, 2004, a reduction of $3.1 million in our loss. This reduction is due 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 nine months ended September 30, 2005, the Other North America region realized an operating loss of $21.9 million on revenues of $16.8 million, as compared to an operating loss of $5.4 million and revenues of $81.5 million for the nine months ended September 30, 2004. This unfavorable variance is primarily related to the sale of Kendall and the expiration of a tolling agreement at our Rockford facility. Kendall and Rockford had operating income of $1.0 million and $6.9 million, respectively, for the nine months ended September 30, of 2004 and revenues of $62.6 million and $16.4 million, respectively. Other operating expenses and depreciation and amortization for our Other North America region for the nine months ended September 30, 2005 were $18.3 million and $5 million, respectively. For the nine months ended September 30, 2004, other operating expenses and depreciation and amortization were $33.6 million and $18.9 million, respectively. The favorable variance in both of these is due to the sale of Kendall.

Australia Region Results

Operating Income

For the nine months ended September 30, 2005, the Australia region realized an operating loss of $2.0 million, as compared to $7.1 million in operating income for the nine months ended September 30, 2004. Unseasonably mild weather and weak pool prices in the first quarter drove the unfavorable results as compared to last year. Higher generation for the nine months ended September 30, 2005 helped to offset weak pool prices, with generation increasing 5.0% over the generation from the same period of 2004.

Revenues

Revenues from our Australia region totaled $161.9 million for the nine months ended September 30, 2005 compared to $146.4 million for the nine months ended September 30, 2004, an increase of $15.5 million. Energy revenues decreased by $12.2 million primarily due to the weak pool prices experienced in the first quarter of the year partially offset by the increased generation. An unseasonably mild summer in Australia drove the average pool price down to $24.22 per MWh from $29.11 per MWh in the first nine months of 2005, a reduction of 7.1%. The 5% increase in generation was due to the full commercialization of the Playford station during the fourth quarter of 2004, compared to 2004. For the nine months ended September 30, 2005, other revenues totaled $17.5 million compared to $2.7 million of other revenues for the nine months ended September 30, 2004. Other revenues were favorably impacted by lower contract amortization of $12.1 million as contracts amortize over time.

Cost of Energy

Fuel costs increased by $8.5 million due to the additional cost of Playford Station as it only became fully operational in the fourth quarter of 2004.

Other Operating Expenses

Other operating expenses for Australia for the nine months ended September 30, 2005 increased by $13.5 million 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

Highlights of events for the nine months ended September 30, 2005

- The repurchase of $645 million par value of our Second Priority Notes, resulting in $44 million of refinancing charges
- The issuance of $250 million in 3.625% Preferred Stock
- The execution of the Accelerated Share Repurchase Agreement whereby we repurchased $250 million of common stock
- Repatriation of $271 million of foreign funds utilizing the tax benefits of the American Jobs Creation Act of 2004
- Cash collateral payments of $598.1 million supporting our hedging activities
- Collection of $70.8 million in an arbitration award related to Termo Rio.
- Execution of the Texas Genco Acquisition Agreement and related financing commitments

Redemption of $645 million of our Second Priority Notes

In February 2005 we redeemed $375.0 million of the Second Priority Notes using the proceeds from the issuance of $420.0 million of 4% Preferred Stock in December 2004. During the first quarter we used existing cash to purchase, at market prices, $40.8 million in face value of our Second Priority Notes. During the third quarter we redeemed an additional $228.8 million in Second Priority Notes using the net proceeds of $246.2 million from the issuance of 3.625% Preferred Stock.

Issuance of 3.625% Preferred Stock

On August 11, 2005, we issued 250,000 shares of 3.625% Preferred Stock to Credit Suisse First Boston Capital LLC, or CSFB, in a private placement. The 3.625% Preferred Stock is recorded based on the proceeds of $250 million net of issuance costs of $3.81 million. We issued the 3.625% Preferred Stock to enable the redemption of our Second Priority Notes.

Accelerated Share Repurchase Plan

On August 11, 2005, we entered into an Accelerated Share Repurchase Agreement with CSFB, pursuant to which we repurchased $250 million of our common stock on that date that equaled a total of 6,346,788 shares which are held in treasury. We funded the repurchase with cash on hand. On or about February 13, 2006, we will receive from, or pay to, CSFB a purchase price adjustment based upon the weighted average value of NRG's common stock over a period of approximately six months, subject to a minimum price of 97% and a maximum price of 103% of the closing price per share on August 10, 2005, or $39.39. Based on the analysis of our common stock price volatility, we have recorded a liability of $7.5 million reflecting the maximum purchase price adjustment expected as of February 13, 2006.

Repatriation of Foreign Funds

During the three month period ended September 30, 2005, NRG repatriated approximately $271 million of accumulated foreign earnings. Only a portion of this amount represents the current earnings and profits which will result in approximately $6.7 million of tax expense. This repatriation was initiated to utilize the tax benefits of the American Jobs Creation Act of 2004 which will expire on December 31, 2005.

To the extent that NRG does not provide deferred income taxes for unremitted earnings, it is management's intent to permanently reinvest those earnings overseas in accordance with Accounting Principle Board Opinion No. 23 *Accounting for Income Taxes-Special Areas*, or APB No. 23.

Liquidity

As of September 30, 2005 and November 3, 2005, we had $1.08 billion in aggregate principal amount of Second Priority Notes, $446.6 million in principal amount outstanding under the term loan, $80.0 million in principal amount outstanding under the revolving credit facility and $350.0 million of the funded letter of credit facility outstanding. As of September 30, 2005 and November 3, 2005, $22.9 million and $14.1 million, respectively, of undrawn letters of credit capacity remained available under the funded letter of credit facility. As of November 3, 2005, the revolving credit facility was undrawn.

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 September 30, 2005 and November 3, 2005, the balance of our collateral posted in support of these contracts was $631.4 million and $452.2 million, respectively.

As of September 30, 2005 our liquidity was $688.7 million and includes $595.8 million of unrestricted and restricted cash. Our liquidity also included $70.0 million of available capacity under our revolving line of credit and $22.9 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. Management believes that these amounts and cash flows from operations will be adequate to finance capital expenditures, to fund dividends to our preferred shareholders and other liquidity commitments. Management continues to regularly monitor the company's ability to finance the needs of its operating, financing and investing activity in a manner consistent with its intention to maintain a steady debt equity ratio of approximately 50%.

Capital Expenditures

Capital expenditures were approximately $45.5 million and $78.3 million for the nine months ended September 30, 2005 and September 30, 2004, respectively. We anticipate that our 2005 capital expenditures will be approximately $115 million and will relate to the operation and maintenance of our existing generating facilities.

Other Liquidity Matters — NOLs and Deferred Tax Assets

As of September 30, 2005, we have no U.S. NOL carryforward due to utilization during the current period. We believe that it is more likely than not that the benefit will not be realized on a substantial portion of the deferred tax assets relating to future tax benefits. This assessment included consideration of positive and negative factors, including our current financial position, historical results of operations and current results of operations, projected future taxable income, including projected operating and capital gains, and available tax planning strategies. Therefore, as of September 30, 2005, a consolidated valuation allowance of $861 million was recorded against the net deferred tax assets, in accordance with SFAS No. 109. However, we have not provided a valuation allowance for approximately $44 million of net deferred tax assets which consist of mark-to-market adjustments per SFAS No.133 and utilization of carryover net operating losses to the extent of taxable income generated for the nine months ended September 30, 2005.

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Cash Flows

	For the Nine Months Ended	
	September 30, 2005	September 30, 2004
	(In thousands)	
Net cash provided (used) by operating activities	(113,802)	595,421
Net cash provided by investing activities	179,317	210,806
Net cash used in financing activities	(672,427)	(227,633)

Net Cash Used or Provided By Operating Activities

For the nine months ended September 30, 2005, cash used by operating activities was $113.8 million, a decrease in operating cash flows of $709.2 million from the nine months ended September 30, 2004. The main contributors to the decrease were payments of $598.1 million during the nine months ended September 30, 2005 for cash collateral to support our hedging and risk management activities, and a non-recurring net receipt of $125 million during the nine months ended September 30, 2004 for a bankruptcy-related net receivable. Excluding the affect of the cash collateral payments mentioned above, cash provided by working capital decreased by $18.3 million during the nine months ended September 30, 2005 compared to the same period in 2004. In addition, distributions from equity method investments during the nine months ended September 30, 2005 decreased by $19.9 million compared to the same period in 2004.

Net Cash Provided By Investing Activities

For the nine months ended September 30, 2005, cash provided by investing activities decreased by $31.5 million, compared to the same period in 2004. During the nine months ended September 30, 2005 we continued to divest non-core assets reflected in the receipt of $105.2 million for the sale of Enfield, Kendall, Northbrook New York and Northbrook Energy, whereas for the same period in 2004 we received $276.2 million for the sale of equity method investments and discontinued operations, a decrease of $170.6 million. This decrease in proceeds was offset by the receipt of $70.8 million related to the TermoRio settlement during 2005 and a comparative increase in cash and cash equivalents from the release of $40.9 million of restricted cash from 2005 to 2004. This amount is explained by the release of $38.2 million of restricted cash at our Flinders facility as a result of our refinancing of Flinders' debt.

Our capital expenditures for the nine months ended September 2005 was $32.8 million less than the same period in 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 facility, which qualified as a capital expenditure.

Net Cash Used in Financing Activities

For the nine months ended September 30, 2005, cash used by financing activities increased by $444.8 million compared to the same period of 2004. The activity for the nine months ended September 30, 2005 consisted of the redemption and repurchase of $644.6 million of our Second Priority Secured Notes, the refinancing of Flinders' debt, our accelerated share repurchase payment and issuance of our 3.625% Preferred Stock. In order to redeem our Second Priority Notes, we issued $420 million of the 4% Preferred Stock in December 2004, and subsequently, $250 million of the 3.625% Preferred Stock in August of 2005. The increase in cash used is explained by this timing difference and normal scheduled principal payments, offset by a net prepayment of $11.1 million of Flinders' debt.

For the nine months ended September 30, 2004, cash used by financing activities of $86.9 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 $508.7 million of our then recently issued term loan.

Texas Genco Acquisition and Future Changes in our Liquidity and Resources

On September 30, 2005, we entered into an Acquisition Agreement with Texas Genco LLC, a Delaware limited liability company, or Texas Genco, and each of the direct and indirect owners of Texas Genco, referred to as the Sellers. Pursuant to the Acquisition Agreement, NRG agreed to purchase all of the outstanding equity interests in Texas Genco for a total purchase price of approximately $5.825 billion, which includes the assumption by the Company of approximately $2.5 billion of indebtedness. The purchase price is subject to adjustment, and includes an equity component valued at $1.8 billion based on a price per share of $40.50 of NRG's common stock and we will assume approximately $2.5 billion of Texas Genco indebtedness. As a result of the Acquisition, Texas Genco will become a wholly owned subsidiary of NRG and will nearly double NRG's U.S. generation portfolio from 12,981 Megawatts to 23,920 Megawatts.

Of the approximately $5.825 billion payable to the Sellers upon consummation of the Acquisition, the Company will pay $4.025 billion in cash, subject to adjustment, and issue a minimum of 35,406,320 shares of the Company's common stock. At the Company's election, the remaining consideration may be comprised of an additional 9,038,125 shares of common stock, or at the Company's election the equivalent in the form of any combination of common stock, additional cash and shares of a new series of the Company's Cumulative Redeemable Preferred Stock. NRG expects to finance the Acquisition through a combination of a new senior secured credit facility, an unsecured high yield notes offering and the sale of common and preferred equity securities in the public markets. Subject to the satisfaction of certain customary conditions, the Acquisition is expected to be consummated in the first quarter of 2006.

If the Texas Genco Acquisition is consummated, the Company intends to refinance substantially all of its currently outstanding indebtedness, to incur a significant amount of new indebtedness and to issue a significant number of shares of common stock and preferred securities. These transactions will significantly alter the Company's capital structure and substantially increase the Company's total debt.

As discussed in more detail above, the consummation of the Acquisition is subject to a number of conditions, including the receipt of certain regulatory approvals. If these conditions are not satisfied or the Acquisition is not consummated for any reason, we could suffer a number of consequences that may adversely affect our business, financial position, results of operations, cash flows and prospects.

In addition to the foregoing, the proposed Acquisition, if consummated, will subject the Company to a number of significant risks and uncertainties, including those relating to our substantial leverage and the increased size of our operations.

Brownfield Developments

As part of our strategy to reinvest capital in our existing assets for reason of repowering and expansion of current generation sites, management is evaluating opportunities within our core areas of operations.

During the third quarter, we received a Title V Air Permit from the Louisiana Department of Environmental Quality to add a fourth unit of generating capacity at our Big Cajun II Generating Station in New Roads, Louisiana. The total capital expenditure expected from the construction of the 675 MW expansion project is $1 billion and would take four years to build. Our Big Cajun II facility serves the electricity needs of Louisiana's 11 electric cooperatives and we believe that there is additional unmet demand for electricity in the area. We are currently evaluating potential partners and customers for this project as they are critical to the consideration of when to proceed with this project.

OFF-BALANCE SHEET ARRANGEMENTS

Obligations Under Certain Guarantee Contracts

NRG and certain of its subsidiaries enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial and performance guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Note 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 does not have any material retained or contingent interests in assets transferred to an unconsolidated entity.

Derivative Instrument obligations

On August 11, 2005 NRG issued the 3.625% Preferred Stock which include a conversion feature which is considered a derivative per FAS 133. Although it is considered a derivative, it is exempt from derivative accounting as it is excluded from the scope pursuant to paragraph 11(a) of SFAS No. 133. Despite this exclusion, per the guidance of EITF Topic D-98 the conversion feature must be marked-to-market. Currently, the conversion feature is valued at $0 as our stock price is outside the conversion range. See Note 15 *Convertible Perpetual Preferred Stock* for further discussion.

Obligations Arising Out of a Variable Interest in an Unconsolidated Entity

As of September 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 $191.9 million and $251.7 million as of September 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.

See Note 13, *Commitments and Contingencies*, to the Condensed Consolidated Financial Statements for a discussion of commitments and contingencies that also include contractual obligations and commercial commitments that occurred during 2005.

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 September 30, 2005	$ 39.0
Average	30.2
High	41.2
Low	19.6

	(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 September 30, 2005 is $39.0 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.

Our collateral posted in support of our management of our electric generation facilities fluctuates based on amount of the portfolio hedged using collateralized contracts and market price movements. Based on a sensitivity analysis a $1 per MWh increase or decrease in electricity prices would cause a change in margin collateral outstanding of approximately $15.3 million. This sensitivity uses simplified assumptions and may not reflect actual market movements.

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 September 30, 2005, we had various interest rate swap agreements with notional amounts totaling approximately $1.2 billion. If the swaps had been discontinued on September 30, 2005, we would have owed the counter-parties approximately $31.7 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 September 30, 2005, a 100 basis point change in interest rates would result in a $7.4 million change in interest expense on a rolling twelve month basis.

At September 30, 2005, the fair value of our long-term debt was $3.1 billion, compared with the carrying amount of $3.0 billion. We estimate that a 1% decrease in market interest rates would have increased the fair value of our long-term debt by $42.3 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 September 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 September 30, 2005 and November 3, 2005, we held collateral support of $184.4 million and $204.3 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 ISOs or RTOs 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 nine months ended September 30, 2005, we derived approximately 52.8% of our total revenues from majority-owned operations from two customers: NYISO accounted for 37.9% and ISO New England accounted for 14.9%. 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 optimization 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 transaction and throughout the period it is held, as is the case with our base-load coal plants. For this reason, transactions 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 transactions 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 optimization 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 September 30, 2005 based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at September 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	(60,380)
Changes in fair value	(584,127)
Fair value of contracts at September 30, 2005	$ (688,178)

Sources of Fair Value Gains/(Losses)

	Fair Value of Contracts at Period End as of September 30, 2005				
	Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years (In thousands)	Maturity in excess of 5 Years	Total Fair Value
Prices actively Quoted	$(414,695)	$(49,906)	$ —	$ —	$ (464,601)
Prices provided by other external sources	(110,332)	(12,090)	(6,692)	(21,971)	(151,085)
Prices based on models and other valuation methods	(1,784)	(21,727)	(18,255)	(30,726)	(72,492)
Total	$(526,811)	$(83,723)	$ (24,947)	$(52,697)	$ (688,178)

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 September 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

Item 2(c). Purchase of Equity Securities by NRG

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
July 1, 2005 – July 31, 2005	—	—	—	—
August 1, 2005 – August 31, 2005	6,346,788(1)	$ 39.39	6,346,788	(1)
September 1, 2005 – September 30, 2005	—	—	—	—
Total Third Quarter	6,346,788	$ 39.39	6,346,788	(1)

(1) On August 9, 2005, we announced that we had committed to repurchase, on August 11, 2005, $250.0 million of our outstanding common stock from Credit Suisse First Boston Capital LLC, or CSFB. On August 11, 2005, we entered into an Accelerated Share Repurchase Agreement, pursuant to which we repurchased 6,346,788 shares of our common stock at a purchase price of $39.39 per share, or an aggregate purchase price of $250.0 million. On or about February 13, 2006, we will receive from, or pay to, CSFB a purchase price adjustment based on the weighted average value of our common stock over a period of approximately six months, to fix our price risk at the time of settlement within a range of 97% to 103% of the closing price of our common stock on August 10, 2005, or $39.39.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Submission of Matters to a Vote of Security Holders

None.

Item 5. Other Information

On October 6, 2005, the Board of Directors of NRG Energy, Inc. formed a Commercial Operations Oversight Committee consisting of Stephen L. Cropper (Chair), Maureen Miskovic and David Crane. The primary responsibility of the new committee is to assist the Board of Directors in fulfilling its responsibilities with respect to the oversight of trading, power marketing and risk management issues at the Company.

Item 6. Exhibits

(a) Exhibits

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: November 7, 2005

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Exhibits	
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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.

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: November 7, 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: November 7, 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: November 7, 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 September 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: November 7, 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.