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: March 31, 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)

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12 b-2 of the Exchange Act).

Yes ☑ No ☐

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

Yes ☑ No ☐

As of May 3, 2005, there were 87,045,501 shares of common stock outstanding.

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
	(In thousands, except per share amounts)	
Operating Revenues		
Revenues from majority-owned operations	$ 601,142	$ 600,265
Operating Costs and Expenses		
Cost of majority-owned operations	452,922	381,753
Depreciation and amortization	48,424	55,006
General, administrative and development	49,894	36,392
Other charges		
Corporate relocation charges	3,455	1,116
Reorganization items	—	6,250
Total operating costs and expenses	554,695	480,517
Operating Income	46,447	119,748
Other Income/(Expense)		
Minority interest in earnings of consolidated subsidiaries	(474)	(508)
Equity in earnings of unconsolidated affiliates	36,964	17,713
Write downs and losses on sales of equity method investments	—	(1,738)
Other income, net	25,502	3,657
Refinancing expenses	(25,024)	(30,417)
Interest expense	(55,991)	(62,729)
Total other expense	(19,023)	(74,022)
Income From Continuing Operations Before Income Taxes	27,424	45,726
Income Tax Expense	4,802	14,280
Income From Continuing Operations	22,622	31,446
Loss From Discontinued Operations, net of Income Taxes	(4)	(1,211)
Net Income	22,618	30,235
Dividends for Preferred Shares	3,872	—
Income Available for Common Stockholders	$ 18,746	$ 30,235
Weighted Average Number of Common Shares Outstanding — Basic	87,043	100,018
Income From Continuing Operations per Weighted Average Common Share — Basic	$ 0.21	$ 0.31
Loss From Discontinued Operations per Weighted Average Common Share — Basic	—	(0.01)
Net Income per Weighted Average Common Share — Basic	$ 0.21	$ 0.30
Weighted Average Number of Common Shares Outstanding — Diluted	87,722	100,018
Income From Continuing Operations per Weighted Average Common Share — Diluted	$ 0.21	$ 0.31
Loss From Discontinued Operations per Weighted Average Common Share — Diluted	—	(0.01)
Net Income per Weighted Average Common Share — Diluted	$ 0.21	$ 0.30

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2005	December 31, 2004
	(In thousands)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 763,025	$ 1,110,045
Restricted cash	78,259	112,824
Accounts receivable — trade, less allowance for doubtful accounts of $1,011 and $1,011	229,392	272,101
Accounts receivable - affiliates	503	—
Current portion of notes receivable and other investments	26,860	85,447
Income taxes receivable	36,650	37,484
Inventory	208,757	248,010
Derivative instruments valuation	35,196	79,759
Prepayments and other current assets	294,149	169,608
Deferred income taxes	1,023	—
Current assets — discontinued operations	3,019	3,010
Total current assets	1,676,833	2,118,288
Property, Plant and Equipment		
In service	3,562,719	3,564,658
Under construction	24,601	17,429
Total property, plant and equipment	3,587,320	3,582,087
Less accumulated depreciation	(254,886)	(207,536)
Net property, plant and equipment	3,332,434	3,374,551
Other Assets		
Equity investments in affiliates	754,240	734,950
Notes receivable and other investments, less current portion — affiliates, less reserve for uncollectible notes receivable of $14,304 and $4,402	118,281	128,046
Notes receivable and other investments, less current portion, less reserve for uncollectible notes receivable of $3,794 and $3,794	650,837	676,476
Intangible assets, net of accumulated amortization of $59,823 and $55,010	284,909	294,350
Debt issuance costs, net of accumulated amortization of $4,120 and $3,635	40,807	48,485
Derivative instruments valuation	24,464	41,787
Funded letter of credit	350,000	350,000
Other assets	60,493	63,095
Total other assets	2,284,031	2,337,189
Total Assets	$7,293,298	$ 7,830,028

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2005	December 31, 2004
	(In thousands, except for share data)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 85,092	$ 512,252
Accounts payable — trade	129,741	166,131
Accounts payable — affiliates	—	5,591
Accrued property, sales and other taxes	13,608	11,134
Accrued salaries, benefits and related costs	23,781	35,206
Accrued interest	44,575	11,057
Derivative instruments valuation	123,742	16,772
Deferred income taxes	—	334
Other bankruptcy settlement	177,425	175,576
Other current liabilities	147,721	152,526
Current liabilities — discontinued operations	1,374	1,362
Total current liabilities	747,059	1,087,941
Other Liabilities		
Long-term debt and capital leases	3,143,369	3,253,866
Deferred income taxes	123,055	134,325
Postretirement and other benefit obligations	109,754	116,383
Derivative instruments valuation	158,458	148,445
Non-current out-of-market contracts	314,021	318,664
Other long-term obligations	79,835	71,055
Non-current liabilities — discontinued operations	1,081	1,081
Total non-current liabilities	3,929,573	4,043,819
Total Liabilities	4,676,632	5,131,760
Minority Interest	6,576	6,104
Commitments and Contingencies		
Stockholders' Equity		
4% Convertible perpetual preferred stock; $.01 par value; 10,000,000 shares authorized, 420,000 issued and outstanding at March 31, 2005 and December 31, 2004 (shown at liquidation value, net of issuance costs)	406,306	406,359
Common stock; $.01 par value; 500,000,000 shares authorized; 100,045,104 and 100,041,935 shares issued at March 31, 2005 and December 31, 2004; 87,045,104 and 87,041,935 outstanding at March 31, 2005 and December 31, 2004	1,000	1,000
Additional paid-in capital	2,420,982	2,417,021
Retained earnings	215,388	196,642
Less treasury stock, at cost — 13,000,000 shares	(405,312)	(405,312)
Accumulated other comprehensive income/(loss)	(28,274)	76,454
Total stockholders' equity	2,610,090	2,692,164
Total Liabilities and Stockholders' Equity	$ 7,293,298	$ 7,830,028

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
	(In thousands)	
Cash Flows from Operating Activities		
Net income	$ 22,618	$ 30,235
Adjustments to reconcile net income to net cash provided by operating activities		
Distributions less/(more) than equity earnings of unconsolidated affiliates	(31,996)	19,709
Depreciation and amortization	48,423	59,114
Reserve for note and interest receivable	(98)	—
Amortization of financing costs and debt discount	2,344	9,243
Write-off of deferred financing costs and debt premium	(8,413)	15,312
Write down and loss on sale of equity method investments	—	1,738
Deferred income taxes and investment tax credits	(5,548)	11,948
Unrealized (gains)/losses on derivatives	85,082	(5,393)
Minority interest	474	1,428
Amortization of power contracts and emission credits	11,153	22,747
Amortization of unearned equity compensation	2,064	—
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions		
Accounts receivable, net	41,506	(29,674)
Xcel Energy settlement receivable	—	288,000
Inventory	39,700	21,035
Prepayments and other current assets	(124,549)	29,793
Accounts payable	(35,701)	(1,978)
Accounts payable – affiliates, net	(9,030)	—
Accrued expenses	18,683	40,529
Other current liabilities	(2,482)	(6,410)
Creditor pool obligation payments	—	(163,000)
Other assets and liabilities	9,611	5,779
Net Cash Provided by Operating Activities	63,841	350,155
Cash Flows from Investing Activities		
Proceeds from sale of investments	—	2,500
Decrease (Increase) in restricted cash and trust funds	34,325	(17,714)
Decrease in notes receivable	68,202	15,940
Capital expenditures	(11,782)	(34,728)
Return of capital from projects	1,095	—
Investments in projects	—	(476)
Net Cash Provided by (Used in) Investing Activities	91,840	(34,478)
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt	203,545	486,028
Payment of dividends to preferred stockholders	(3,872)	—
Deferred debt issuance costs	(1,293)	(7,233)
Issuance expense of preferred shares	(53)	—
Principal payments on short and long-term debt	(698,943)	(516,912)
Net Cash Used in Financing Activities	(500,616)	(38,117)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(2,033)	(401)
Change in Cash from Discontinued Operations	(52)	3,098
Net Increase/(Decrease) in Cash and Cash Equivalents	(347,020)	280,257
Cash and Cash Equivalents at Beginning of Period	1,110,045	551,223
Cash and Cash Equivalents at End of Period	$ 763,025	$ 831,480

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME/(LOSS)
Three Months Ended March 31, 2005 and 2004
(Unaudited)

	Serial Preferred		Common						
	Stock	Shares	Stock	Shares	Additional Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income/(Loss)	Total Stock-holders' Equity
					(in thousands)				
Balances at December 31, 2003	$ —	—	$1,000	100,000	$2,403,429	$ 11,025	$ —	$ 21,802	$2,437,256
Net income						30,235			30,235
Foreign currency translation adjustments and other								(2,413)	(2,413)
Deferred unrealized loss on derivatives, net								(22,565)	(22,565)
Comprehensive income for the three months ended March 31, 2004									5,257
Equity based compensation					3,342				3,342
Balances at March 31, 2004	$ —	—	$1,000	100,000	$2,406,771	$ 41,260	$ —	$ (3,176)	$2,445,855
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						22,618			22,618
Foreign currency translation adjustments and other								(22,841)	(22,841)
Deferred unrealized loss on derivatives, net								(81,887)	(81,887)
Comprehensive loss for the three months ended March 31, 2005									(82,110)
Preferred stock issue costs	(53)								(53)
4% preferred stock dividend						(3,872)			(3,872)
Equity based compensation				3	3,961				3,961
Balances at March 31, 2005	$406,306	420	$1,000	87,045	$2,420,982	$215,388	$(405,312)	$ (28,274)	$2,610,090

See notes to consolidated financial statements.

NRG ENERGY, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1 — General

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

Note 2 — Summary of Significant Accounting Policies

Basis of Presentation

The accompanying unaudited interim 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 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 consolidated financial statements contain all material adjustments (consisting of normal, recurring accruals) necessary to present fairly our consolidated financial position as of March 31, 2005, the results of our operations and stockholders’ equity for the three months ended March 31, 2005 and 2004, and our cash flows for the three months ended March 31, 2005 and 2004. Certain prior-year amounts have been reclassified for comparative purposes.

Restricted Cash

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

Accounting Estimates

Management of the Company is required to make certain estimates and assumptions during the preparation of the consolidated financial statements in accordance with generally accepted accounting principles. These estimates and assumptions impact the reported amount of assets and liabilities and disclosures of contingent assets and liabilities as of the date of the consolidated financial statements. They also impact the reported amount of net earnings during any period. Actual results could differ from those estimates.

Note 3 — Discontinued Operations

We have classified certain business operations, and gains/(losses) recognized on sale, as discontinued operations for projects that were sold or have met the required criteria for such classification. The financial results for all of these businesses have been accounted for as discontinued operations. Accordingly, current period operating results and prior periods have been restated to report the operations as discontinued.

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

The assets and liabilities reported in the balance sheets as of March 31, 2005 and 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 months ended March 31, 2005, discontinued operations consisted of various expenses related to NRG McClain as noted above. For the three months ended March 31, 2004, discontinued operations included our NRG McClain LLC; Penobscot Energy Recovery Company, or PERC; Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee; Hsin Yu, LSP Energy (Batesville) and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha and NEO Tajiguas LLC). McClain, PERC and LSP Energy (Batesville) are included in our Wholesale Power Generation — Other North America segment. Cobee and Hsin Yu are included in the All Other — Other International segment and the four NEO projects are included in the All Other - Alternative Energy segment.

Summarized results of operations of discontinued operations were as follows:

	Three Months Ended	
	March 31, 2005	March 31, 2004
	(In thousands)	
Operating revenues	$ —	$ 58,876
Pretax loss from operations of discontinued components	(4)	(230)
Loss from operations of discontinued operations, net of income taxes	(4)	(1,211)

Note 4 —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 three months ended March 31, 2005 and 2004, we recorded $3.5 million and $1.1 million, respectively, for charges related to our corporate relocation activities, primarily for employee severance and termination benefits, employee related transition costs and lease termination costs. These charges are classified separately in our statement of operations, in accordance with SFAS No. 146, "*Accounting for Costs Associated with Exit or Disposal Activities*". Relocation charges for the year ended December 31, 2004 were $16.2 million. We expect to incur an additional $1.8 million in the second and third quarters of 2005 of SFAS No. 146-classified expenses in connection with corporate relocation charges for a total of $21.4 million.

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

	Year Ended December 31, 2004	Three Months Ended March 31, 2005	Yet to be Incurred	Expected Total Charges
		(In thousands)		
Employee related transition costs	$ 8,595	$ 510	$ 1,211	$ 10,316
Severance and termination benefits	6,505	137	19	6,661
Lease termination costs	1,067	2,808	588	4,463
Total corporate relocation charges	$ 16,167	$ 3,455	$ 1,818	$ 21,440

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 March 31, 2005
		(In thousands)		
Employee related transition costs	$ (1,425)	$ 510	$ 611	$ (304)
Severance and termination benefits	4,189	137	(2,803)	1,523
Lease termination costs	796	2,808	(143)	3,461
Total	$ 3,560	$ 3,455	$ (2,335)	$ 4,680

As of March 31, 2005, the restructuring liability was $4.7 million the majority of which is included in other current liabilities on the consolidated balance sheet. All restructuring costs are recorded at our corporate level within our All Other — Other segment, in the corporate relocation charges line on the consolidated statement of operations. Severance and termination benefits will require that cash payments be made through the fourth quarter of 2005. Lease termination costs will require that cash payments be made through the fourth quarter of 2006.

Note 5 — Investments Accounted for by the Equity Method

We have investments in various international and domestic energy projects, certain of which are accounted for under the equity method of accounting. The equity method of accounting is applied to such investments in affiliates, which include joint ventures and partnerships, because the ownership structure prevents us from exercising a controlling influence over operating and financial policies of the projects. Under this method, equity in pretax income or losses of domestic partnerships and, generally, in the net income or losses of international projects, are reflected as equity in earnings of unconsolidated affiliates.

We have ownership interests in two companies that were considered significant as defined by applicable SEC regulations as of March 31, 2005: West Coast Power LLC and Enfield Energy Centre Limited. We account for our ownership share of these investments using the equity method. On April 1, 2005, we completed the sale of our 25% interest in Enfield to Infrastructure Alliance Limited. The sale resulted in net pretax proceeds of $59.5 million. A pre-tax gain of approximately $6.0 million will be recorded in the second quarter of 2005 upon completion of the sale. Additionally, we expect to receive an additional amount of approximately $4.0 million based upon the post-closing working capital adjustment, which will also be recorded as a pre-tax gain on sale when determinable.

West Coast Power LLC Summarized Financial Information

For the three months ended March 31, 2005, we recorded equity earnings of $4.1 million for West Coast Power after adjustments for the reversal of $3.2 million of project level depreciation expense. For the three months ended March 31, 2004, we recorded equity earnings of $6.0 million for West Coast Power after adjustments for the reversal of $2.0 million of project level depreciation expense, offset by a decrease in earnings related to $31.0 million of amortization of the intangible asset for the California Department of Water Resources, or CDWR contract. This contract terminated on December 31, 2004. The following table summarizes financial information for West Coast Power, including interests owned by us and other parties for the periods shown below:

Summarized Results of Operations

	Three Months Ended	
	March 31, 2005	March 31, 2004
	(In millions)	
Operating revenues	$ 86	$ 167
Operating income	$ —	$ 70
Net income (pretax)	$ 2	$ 70

Note 6 — Accounting for Derivative Instruments and Hedging Activities

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

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

For derivatives that are neither designated as cash flow hedges or do not qualify for hedge accounting treatment, the changes in the fair value will be immediately recognized in earnings.

Under the guidelines established by SFAS No. 133, as amended, certain derivative instruments may qualify for the normal purchase and sale exception and are therefore exempt from fair value accounting treatment.

SFAS No. 133 applies to our energy related commodity contracts, interest rate swaps and foreign exchange contracts.

Accumulated Other Comprehensive Income (OCI)

The following table summarizes the effects of SFAS No. 133 on our OCI balance attributable to hedged derivatives for the three months ended March 31, 2005 before income taxes:

	Energy Commodities	Interest Rate	Foreign Currency	Total
		(In thousands)		
Accumulated OCI balance at December 31, 2004	$ 5,482	$ 1,987	$ —	$ 7,469
Unwound from OCI during the period:				
— Due to unwinding of previously deferred amounts	(2,755)	604	—	(2,151)
Mark to market of hedge contracts (net of tax)	(89,770)	10,034	—	(79,736)
Accumulated OCI balance at March 31, 2005	$ (87,043)	$ 12,625	$ —	$(74,418)
Gains/(Losses) expect to unwind from OCI during the next 12 months	(76,283)	6,473	—	(69,810)

The following table summarizes the effects of SFAS No. 133 on our OCI balance attributable to hedged derivatives for the three months ended March 31, 2004:

	Energy Commodities	Interest Rate	Foreign Currency	Total
		(In thousands)		
Accumulated OCI balance at December 31, 2003	$ (1,953)	$ 1,600	$ (170)	$ (523)
Unwound from OCI during the period:				
— Due to unwinding of previously deferred amounts	400	(4)	170	566
Mark to market of hedge contracts (net of tax of $0)	(13,718)	(9,413)	—	(23,131)
Accumulated OCI balance at March 31, 2004	$ (15,271)	$ (7,817)	$ —	$(23,088)

Gains of $2.2 million and losses of $0.6 million were reclassified from OCI to current period earnings during the three months ended March 31, 2005 and 2004, 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 months ended March 31, 2005 and 2004, we recorded losses in OCI of $79.7 million and $23.1 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 March 31, 2005 was an unrecognized loss of approximately $74.4 million. We expect $69.8 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 table summarizes the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the three months ended March 31, 2005:

	Energy Commodities	Interest Rate	Foreign Currency	Total
		(In thousands)		
Revenue from majority-owned subsidiaries	$ (87,213)	$ —	$ —	$(87,213)
Equity in net earnings of unconsolidated affiliates	11,868	—	—	11,868
Cost of operations	4,428	—	—	4,428
Total statement of operations impact before tax	$ (70,917)	$ —	$ —	$(70,917)

The following table summarizes the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the three months ended March 31, 2004:

	Energy Commodities	Interest Rate	Foreign Currency	Total
		(In thousands)		
Revenue from majority-owned subsidiaries	$ 896	$ —	$ —	$ 896
Equity in net earnings of unconsolidated affiliates	(1,158)	—	—	(1,158)
Cost of operations	(503)	—	—	(503)
Interest expense	—	411	—	411
Total statement of operations impact before tax	$ (765)	$ 411	$ —	$ (354)

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.

Any ineffectiveness on commodity cash flow hedges during the three months ended March 31, 2005 and 2004 was immaterial to our financial results.

During the three months ended March 31, 2005 and 2004, our pre-tax earnings were affected by an unrealized loss of $82.8 million and an unrealized gain of $0.4 million $0, 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 months ended March 31, 2005 and 2004, we reclassified gains of $2.8 million and losses of $0.4 million, respectively, from OCI to current period earnings and expect to reclassify approximately $76.3 million of deferred losses to earnings during the next twelve months on energy related derivative instruments accounted for as hedges. At March 31, 2005, we had hedge and non-hedge energy related commodities financial instruments extending through March 2025.

Interest Rates

We are exposed to changes in interest rates through our issuance of variable rate and fixed rate debt. In order to manage this interest rate risk, we have entered into interest-rate swap agreements. At March 31, 2005, all of our interest rate swap arrangements have been designated as either cash flow or fair value hedges. No ineffectiveness was recognized on interest rate swaps that qualify as hedges during the three months ended March 31, 2005 and 2004.

During the three months ended March 31, 2005 and 2004, our pre-tax earnings were not impacted and increased by an unrealized gain of $0.4 million, respectively, associated with changes in the fair value of interest rate derivative instruments not accounted for as hedges in accordance with SFAS No. 133. One of these instruments is a $400 million swap to pay fixed for floating, which was not designated as a 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, changes in value subsequent to April 1, 2004 are deferred and recorded as part of OCI.

During the three months ended March 31, 2005 and 2004, we reclassified losses of $0.6 million and $4,000, respectively, from OCI to current period earnings and expect to reclassify approximately $6.5 million of deferred gains to earnings during the next twelve months associated with interest rate swaps accounted for as hedges.

At March 31, 2005, we had various interest-rate swap agreements extending through June 2019.

Foreign Currency Exchange Rates

To preserve the U.S. dollar value of projected foreign currency cash flows, we may hedge, or protect those cash flows if appropriate foreign hedging instruments are available. As of March 31, 2005, the results of any outstanding foreign currency exchange contracts were immaterial to our financial results.

Note 7 —Long-term Debt and Capital Leases

NRG Energy Corporate Debt

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

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

As of May 3, 2005, our $150.0 million corporate revolving credit facility remained undrawn.

Certain Events Related to Project-Level Debt

In February 2005, NRG Flinders amended its debt facility of AUD 279.4 million (approximately US $218.5 million) in floating-rate debt. The amendment extended the maturity to February 2017, reduced borrowing costs and reserve requirements, reduced debt service coverage ratios, removed mandatory cash sharing arrangements, and made other minor modifications to terms and conditions. The facility includes an AUD 20.0 million (US $15.7 million) working capital and performance bond facility, under which an AUD 15.5 million (US $12.0 million) indemnity has been issued as of March 31, 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 another voluntary prepayment of AUD 10.5 million (US $8.1 million), reducing the outstanding amount to AUD 198.9 million (US $153.9 million). NRG Flinders retains the right to redraw these amounts at any time.

Note 8 — Earnings Per Share

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

	Three Months Ended March 31, 2005	Three Months Ended March 31, 2004
	(In thousands, except per share data)	
Basic earnings per share		
Numerator:		
Income from continuing operations	$ 22,622	$ 31,446
Preferred stock dividends	(4,200)	—
Net income available to common stockholders from continuing operations	18,422	31,446
Discontinued operations, net of tax	(4)	(1,211)
Net income available to common stockholders	$ 18,418	$ 30,235
Denominator:		
Weighted average number of common shares outstanding	87,043	100,018
Basic earnings per share:		
Income from continuing operations	$ 0.21	$ 0.31
Discontinued operations, net of tax	—	(0.01)
Net income	$ 0.21	$ 0.30
Diluted earnings per share		
Numerator		
Net income available to common stockholders from continuing operations	$ 18,422	$ 31,446
Discontinued operations, net of tax	(4)	(1,211)
Net income available to common stockholders	$ 18,418	$ 30,235
Denominator:		
Weighted average number of common shares outstanding	87,043	100,018
Incremental shares attributable to the issuance of nonvested restricted stock units (treasury stock method)	398	—
Incremental shares attributable to the assumed conversion of deferred stock units (if-converted method)	68	—
Incremental shares attributable to the issuance of nonvested nonqualifying stock options (treasury stock method)	213	—
Total dilutive shares	87,722	100,018
Diluted earnings per share:		
Income from continuing operations	$ 0.21	$ 0.31
Discontinued operations, net of tax	—	(0.01)
Net income	$ 0.21	$ 0.30

For the three months ended March 31, 2005, outstanding preferred shares which are convertible into 10,500,000 shares of common stock were not included in the computation because the effect would be anti-dilutive. For the three months ended March 31, 2004, options to purchase 727,751 shares of common stock at an average price of $23.14 per share were not included in the computation because the effect would be anti-dilutive.

Note 9 — 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 – West Coast, Wholesale Power Generation – Other North America and Wholesale Power Generation – Australia. These reportable segments are distinct components with separate operating results and management structures in place. Included in the All Other category are our Wholesale Power Generation – Other International operations, our Alternative Energy operations, our Non – Generation operations and an Other component which includes primarily our corporate charges (primarily interest expense) that have not been allocated to the reportable segments and the remainder of our operations which are not significant. We have presented this detail within the All Other category, as we believe that this information is important to a full understanding of our business.

Beginning January 1, 2005 management decided to change the allocation criteria of corporate general and administrative expenses to the segments. Prior to 2005, corporate general and administrative expenses were allocated based on an analysis of man hours spent on work for each segment. As of January 1, 2005, corporate general and administrative expenses are allocated based on the forecasted revenue to be generated by each segment. In the following table, we have included a reconciliation of the increase/(decrease) in net income by segment for the three month period ended March 31, 2005, assuming the prior allocation criteria was still in effect.

	Three Months Ended March 31, 2005									
	Wholesale Power Generation						All Other			
	Northeast	South Central	West Coast	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	(in thousands)									
Operations										
Operating revenues	$ 332,460	$ 117,146	$ 175	$ 5,147	$ 48,786	$ 43,037	$ 14,946	$ 40,878	$ (1,433)	$ 601,142
Depreciation and amortization	18,609	15,142	198	1,993	6,594	796	1,316	2,739	1,037	48,424
Equity in earnings (losses) of unconsolidated affiliates	—	—	4,725	1,806	6,137	24,277	19	—	—	36,964
Income/(loss) from continuing operations before income taxes	32,860	9,306	3,287	(4,937)	10,814	46,337	780	5,124	(76,147)	27,424
Net income/(loss) from continuing operations	32,860	9,306	3,259	(5,158)	10,180	42,268	538	5,109	(75,740)	22,622
Net income/(loss) from discontinued operations, net of income taxes	—	—	—	(4)	—	—	—	—	—	(4)
Net income/(loss)	$ 32,860	$ 9,306	$ 3,259	$ (5,162)	$ 10,180	$ 42,268	$ 538	$ 5,109	$ (75,740)	$ 22,618
Total assets	$1,951,943	$1,073,851	$ 291,320	$ 769,367	$872,198	$ 950,431	$ 60,208	$ 546,671	$777,309	$7,293,298

If the Company continued using the previous years allocation method for corporate general and administrative expenses, the effect to the net income of each segment for the three months ended March 31, 2005 would be as follows:

Net income/(loss) as reported	$ 32,860	$ 9,306	$ 3,259	$ (5,162)	$ 10,180	$ 42,268	$ 538	$ 5,109	$ (75,740)	$ 22,618
Increase/(decrease) in net income	6,589	3,550	(296)	(325)	1,694	1,078	382	1,469	(14,142)	—
Adjusted net income/(loss)	$ 39,449	$ 12,856	$ 2,963	$ (5,487)	$ 11,874	$ 43,346	$ 920	$ 6,578	$ (89,882)	$ 22,618

	Three Months Ended March 31, 2004									
	Wholesale Power Generation						All Other			
	Northeast	South Central	West Coast	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	(in thousands)									
Operations										
Operating revenues	$330,540	$95,265	$ (3,322)	$ 20,835	$62,229	$ 40,066	$ 13,599	$ 42,726	$ (1,673)	$600,265
Depreciation and amortization	18,529	16,962	202	7,610	5,125	724	1,389	3,124	1,341	55,006
Equity in earnings/(losses) of unconsolidated affiliates	—	—	6,597	232	3,172	7,482	229	—	1	17,713
Income/(loss) from continuing operations before income taxes	87,428	11,377	1,363	(9,902)	16,400	14,354	894	8,911	(85,099)	45,726
Net income/(loss) from continuing operations	87,428	11,377	1,211	(10,237)	13,136	10,210	890	8,734	(91,303)	31,446
Net income/(loss) on discontinued operations, net of income taxes	—	—	—	(982)	—	120	(346)	—	(3)	(1,211)
Net income/(loss)	$ 87,428	$11,377	$ 1,211	$ (11,219)	$13,136	$ 10,330	$ 544	$ 8,734	$(91,306)	$ 30,235

Note 10 — Income Taxes

Income tax expense was $4.8 million and $14.3 million for the three months ended March 31, 2005 and 2004, respectively. The income tax expense for the three months ended March 31, 2005 and 2004 includes domestic tax expense of $0 million and $6.7 million, respectively, and foreign tax expense of $4.8 million and $7.6 million, respectively.

A reconciliation of the U.S. statutory rate to our effective tax rate from continuing operations for the three months ended March 31, 2005 and March 31, 2004 are as follows:

	Three Months Ended March 31, 2005		Three Months Ended March 31, 2004	
	Amount	Rate	Amount	Rate
	(Dollars in thousands)			
Income/(Loss) From Continuing Operations Before Income Taxes	$ 27,424		$ 45,726	
Tax at 35%	9,598	35.0%	16,004	35.0%
State taxes	(2,373)	(8.7)%	719	1.6%
Foreign operations	(23,050)	(84.1)%	(1,944)	(4.3)%
Valuation allowance	20,424	74.5%	—	—
Permanent differences, reserves, other	203	0.7%	(499)	(1.1)%
Income Tax Expense/(Benefit)	$ 4,802	17.5%	$ 14,280	31.2%

For U.S. income tax purposes, the Company generated additional net deferred tax assets for the three months ended March 31, 2005 of which a full valuation allowance was applied due to the uncertainty of utilization in future periods.

No U.S. income tax expense is realized for the three months ended March 31, 2005.

The effective income tax rate for the three months ended March 31, 2005 differs from the U.S. statutory rate of 35% due to the appropriation of a full valuation allowance and due to earnings in foreign jurisdictions taxed at rates lower than the U.S. statutory rate.

We believe that it is more likely than not that a benefit will not be realized on a substantial portion of our deferred tax assets. This assessment included consideration of positive and negative evidence, including our current financial position and results of current operations, projected future taxable income, including projected operating and capital gains and our available tax planning strategies. Therefore, as of March 31, 2005, a valuation allowance of $736 million was recorded against the net deferred tax assets, including net operating loss carryforwards.

Note 11 — Benefit Plans and Other Postretirement Benefits

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

NRG Energy Pension and Postretirement Medical Plans

Components of Net Periodic Benefit Cost

The net annual periodic pension cost for the three months ended March 31, 2005 and 2004 related to all of our plans, include the following components:

	Pension Benefits		Other Benefits	
	Three Months Ended		Three Months Ended	
	March 31, 2005	March 31, 2004	March 31, 2005	March 31, 2004
	(In thousands)			
Service cost benefits earned	$ 3,056	$ 2,950	$ 488	$ 465
Interest cost on benefit obligation	938	738	731	630
Amortization of net (gain)/loss	—	—	19	—
Expected return on plan assets	(81)	—	—	—
Curtailment gain	(335)	—	—	—
Net periodic benefit cost	$ 3,578	$ 3,688	$ 1,238	$ 1,095

Note 12 — Commitments and Contingencies

Legal Issues

Set forth below is a description of our material legal proceedings. In addition to the matters described below, we are party to 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 financial condition, results of operations or cash flows.

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

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

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

California Wholesale Electricity Litigation and Related Investigations

We, West Coast Power, LLC, or WCP, WCP's four operating subsidiaries, Dynegy, Inc. and numerous other unrelated parties are the subject of numerous lawsuits arising based on events occurring in the California power market. Through our subsidiary, NRG West Coast Power LLC, we are a 50 percent beneficial owner with Dynegy of WCP, which owns, operates and markets the power of four California plants. Dynegy and its affiliates and subsidiaries are responsible for gas procurement and marketing and trading activities on behalf of WCP. The complaints primarily allege that the defendants engaged in unfair business practices, price fixing, antitrust violations, and other market "gaming" activities. Certain of these lawsuits, which seek unspecified treble damages and injunctive relief, were consolidated and made a part of a Multi-District Litigation proceeding before the U.S. District Court for the Middle District of California. 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 and on February 22, 2005, the Supreme Court ordered the U.S. Solicitor General to submit its views on the petition.

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

Regarding the remaining cases, in December 2002, the U.S. District Court for the Southern District of California 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. We anticipate that the cases will be remanded to state court in 2005 at which time the defendants will again raise filed rate and federal preemption challenges. In the Northern California cases, on February 25, 2005, the Ninth Circuit affirmed the district court's decision to dismiss all of the defendants' cases.

In addition to the Multi-District Litigation discussed above, numerous other cases, including putative class actions, have been filed in state and federal court on behalf of business and residential electricity consumers which name us and/or WCP and/or certain subsidiaries of WCP, in addition to numerous other defendants. The complaints allege the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades, and violated California's antitrust law and unfair business practices law. The complaints seek restitution and disgorgement, civil fines, compensatory and punitive damages, attorneys' fees and declaratory and injunctive relief. Motion practice is proceeding in these cases and dispositive motions have been filed in several.

In certain of the above referenced cases, Dynegy is defending WCP and/or its subsidiaries pursuant to a limited indemnification agreement while in the others, Dynegy's counsel is representing it and WCP and/or its subsidiaries with each party responsible for half of the costs. Where NRG Energy is named, we are defending the case and bear our own costs of defense.

FERC Proceedings

There are a number of proceedings in which WCP and WCP subsidiaries are parties, which are either pending before FERC or on appeal from FERC to various U.S. Courts of Appeal. These cases involve, among other things, allegations of physical withholding, a FERC-established price mitigation plan determining maximum rates for wholesale power transactions in certain spot markets, and the enforceability of, and obligations under, various contracts with, among others, the California Independent System Operator, the CDWR and the State of California. Among these is a demand by the State of California for FERC to abrogate the CDWR contract between the State and subsidiaries of WCP. In 2003, FERC rejected this demand and denied rehearing. The case was appealed to the 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." As has Dynegy, we and subsidiaries of WCP have responded to interrogatories, document requests, and to requests for interviews.

NRG Bankruptcy Cap on California Claims

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

New York Operating Reserve Markets

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

Connecticut Congestion Charges

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

New York Environmental Settlement

In January 2002, the New York Department of Environmental Conservation, or NYSDEC, sued Niagara Mohawk Power Corporation, or NiMo, and us in federal court in New York asserting that projects undertaken at our Huntley and Dunkirk plants by

NiMo, the former owner of the facilities, violated federal and state laws. On January 11, 2005, we reached an agreement to settle this matter whereby we will reduce levels of sulfur dioxide by over 86 percent and nitrogen oxide by over 80 percent in aggregate at the Huntley and Dunkirk plants. We are not subject to any penalty as a result of the settlement. Through the end of the decade, we expect that our ongoing compliance with the emissions limits set out in the settlement will be achieved through capital expenditures already planned. This includes our conversion to low sulfur western coal at the Huntley and Dunkirk plants that will be completed by spring 2006. On April 6, 2005, NYSDEC filed a motion with the court to enter the Consent Decree and on April 19, 2005, we filed a supporting motion. In a related case, on October 18, 2004, the parties reached a confidential settlement with respect to NiMo's obligation to indemnify us for any related compliance costs associated with resolution of the NYSDEC action.

Station Service Disputes

On October 2, 2000, NiMo commenced an action against us in New York state court seeking damages related to our alleged failure to pay retail tariff amounts for utility services at the Dunkirk Plant between June 1999 and September 2000. The parties agreed to consolidate this action with two other actions against the Huntley and Oswego Plants. On October 8, 2002, by Stipulation and Order, this action was stayed pending submission to FERC of some or all of the disputes in the action. The potential loss inclusive of amounts paid to NiMo and accrued is approximately $23.2 million. In a companion action at FERC, NiMo asserted the same claims and legal theories and on November 19, 2004, FERC denied NiMo's petition and ruled that the NRG facilities could net their service station obligations over a 30 calendar day period from the day NRG acquired the facilities. In addition, FERC ruled that neither NiMo nor the New York Public Service Commission could impose a retail delivery charge on the NRG facilities, because they are interconnected to transmission and not to distribution. On April 22, 2005, FERC denied NiMo's motion for rehearing. As NiMo has the right to appeal the FERC's denial, we will not reverse any amounts accrued until such time as it is assured that our risk of loss has ceased. At this time, we cannot predict the outcome of this matter.

On December 14, 1999, NRG Energy acquired certain generating facilities from CL&P. A dispute arose over station service power and delivery services provided to the facilities. On December 20, 2002, as a result of a petition filed at FERC by Northeast Utilities Services Company on behalf of itself and CL&P, FERC issued an Order finding that at times when NRG Energy is not able to self-supply its station power needs, there is a sale of station power from a third-party and retail charges apply. In August 2003, the parties agreed to submit the dispute to binding arbitration, however, the parties have yet to agree on a description of the dispute and on the appointment of a neutral arbitrator. The potential loss inclusive of amounts paid to CL&P and accrued could exceed $6 million.

U.S. Environmental Protection Agency

On January 27, 2004, our subsidiaries, Louisiana Generating, LLC and Big Cajun II, received an initial and, thereafter, subsequent requests under Section 114 of the federal Clean Air Act from EPA Region 6 seeking information primarily relating to physical changes made at Big Cajun II. Louisiana Generating, LLC and Big Cajun II submitted several responses to the USEPA. On February 15, 2005, Louisiana Generating, LLC received a Notice of Violation alleging violations of the New Source Review provisions of the Clean Air Act at Big Cajun II Units 1 and 2 from 1998 through the Notice of Violation date. On April 7, 2005, a meeting was held with USEPA and the Department of Justice and additional information was provided to the agency. Given the preliminary stage of this NOV process, the Company cannot predict the outcome of this matter at this time, but it is actively engaged with USEPA to address the issues.

TermoRio Litigation

TermoRio was a green field 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. On March 8, 2003, the arbitral tribunal decided most, but not all, of the issues in our favor and awarded us approximately US$80 million. On June 4, 2004, NRG Energy commenced a lawsuit in the U.S. District Court for the Southern District of New York seeking to enforce the arbitration award. On February 16, 2005, a conditional settlement agreement was signed with our former partner Petrobras, whereby Petrobras is obligated to pay us US$70.825 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 US$12.3 million that is currently being held by Petrobras pending a ruling in a related dispute with a third-party. This related dispute is also being accounted for as a gain contingency.

Itiquira Energetica, S.A.

Our Brazilian project company, Itiquira Energetica S.A., the owner of a 156 MW hydro project in Brazil, is in arbitration with the former EPC contractor for the project, Inepar Industria e Construcoes, or Inepar. The dispute was commenced by Itiquira in September of 2002 and pertains to certain matters arising under the former EPC contract. Itiquira seeks $40 million and asserts that Inepar breached the contract. Inepar seeks $10 million and alleges that Itiquira breached the contract. Final written arguments were submitted on January 28, 2005, to the court of arbitration and a decision is expected by the close of the second quarter of 2005.

CFTC Trading Litigation

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

Additional Litigation

In addition to the foregoing, 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 financial condition, results of operations or cash flows.

The Company believes that it has valid defenses to the legal proceedings and investigations described above 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 above, the Company is unable to predict the outcome 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.

Pursuant to the requirements of Statement of Financial Accounting Standards 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. 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.

Disputed Claims Reserve

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

Environmental Matters

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

Northeast Region

Significant amounts of ash are contained in landfills at on and off-site locations. At Dunkirk, Huntley, Somerset and Indian River, ash is disposed at landfills owned and operated by the Company. The Company maintains financial assurance to cover costs associated with closure, post-closure care and monitoring activities. The Company has funded a trust in the amount of approximately $5.9 million to provide such financial assurance in New York and $6.8 million in Delaware. The Company must also maintain financial assurance for closing interim status "RCRA facilities" at the Devon, Middletown, Montville and Norwalk Harbor Generating Stations and has funded a trust in the amount of $1.5 million accordingly.

The Company inherited historical clean-up liabilities when it acquired the Somerset, Devon, Middletown, Montville, Norwalk Harbor, Arthur Kill and Astoria Generating Stations. During installation of a sound wall at Somerset Station in 2003, oil contaminated soil was encountered. The Company has delineated the general extent of contamination, determined it to be minimal, and has placed an activity use limitation on that section of the property. Site contamination liabilities arising under the Connecticut Transfer Act at the Devon, Middletown, Montville and Norwalk Harbor Stations have been identified. The Company has proposed a remedial action plan to be implemented over the next two to eight years (depending on the station) to address historical ash contamination at the facilities. The total estimated cost is not expected to exceed $1.5 million. Remedial obligations at the Arthur Kill generating station have been established in discussions between the Company and the NYSDEC and are estimated to cost between $1 million and $2 million. Remedial investigations continue at the Astoria generating station with long-term clean-up liability expected to be within the range of $2.5 million to $4.3 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.

We estimate that we will incur total environmental capital expenditures of $197.6 million during 2005 through 2010 for the facilities in New York, Connecticut, Delaware and Massachusetts. These expenditures will be primarily related to installation of particulate, SO_2 and NO_X controls, as well as installation of BTA under the Phase II 316(b) Rule.

Huntley Power LLC, Dunkirk Power LLC and Oswego Power LLC were issued Notices of Violation for opacity exceedances and entered into a Consent Order with NYSDEC, effective March 31, 2004. The Consent Order required the respondents to pay a civil penalty of $1.0 million which was paid in April 2004. The Order also establishes stipulated penalties (payable quarterly) for future violations of opacity requirements and a compliance schedule. The Company is currently in dispute with NYSDEC over the method of calculation for stipulated penalties. The Company has placed $1.3 million in a reserve account as of March 31, 2005, and does not believe that the final resolution will involve a material larger amount.

South Central Region

Liabilities associated with closure, post-closure care and monitoring of the ash ponds owned and operated on site at the Big Cajun II Generating Station are addressed through the use of a trust fund maintained by the Company in the amount of approximately $5.0 million. Annual payments are made to the fund in the amount of approximately $116,000.

We estimate approximately $271 million of capital expenditures will be incurred during the period 2005 through 2010 for our South Central facilities, primarily related to installation of particulate, SO_2 and NO_X controls, as well as studies for installation of BTA under the Phase II 316(b) Rule.

West Coast Region

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

Regulatory Matters

NYISO Claims

In November 2002, NYISO notified us of claims related to New York City mitigation adjustments, general NYISO billing adjustments and other miscellaneous charges related to sales between November 2000 and October 2002. New York City mitigation adjustments totaled $11.4 million. The issue related to NYISO's concern that NRG would not have sufficient revenue to cover subsequent revisions to its energy market settlements. As of December 31, 2004, NYISO held $3.9 million in escrow for such future settlement revisions.

Commitments

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

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

In December 2004, we entered into a long-term coal transport agreement with the Burlington Northern and Santa Fe Railway Company and affiliates of American Commercial Lines LLC to deliver low sulfur coal to our Big Cajun II facility in New Roads, Louisiana beginning April 1, 2005. In March 2005, we entered into an agreement to purchase coal over a period of four years and nine months from Buckskin Mining Company, or Buckskin. The coal will be sourced from Buckskin's mine in the Powder River Basin, Wyoming, and will be used primarily in NRG Energy's coal-burning generation plants in the South Central region of the United States. Including this contract and other contracts, total coal purchase obligations increased by $160.1 million.

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 13 — 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.

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.

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.

On February 28, 2005, concurrent with the amendment of its debt facility, our Flinders subsidiary issued, under its amended AUD 20.0 million (US $15.5 million) working capital and performance bond facility sponsored by National Australia Bank Limited, an AUD 15.5 million (US $12.0 million) indemnity to the Australia and New Zealand Banking Group Limited (ANZ), the previous sponsor of the facility. The indemnity expires on October 31, 2006 and indemnifies ANZ against potential claims for guarantees or letters of credit issued under the facility prior to February 28, 2005.

On February 18, 2005, we issued a guarantee to the benefit of General Electric Railcar Service Corporation. We guarantee the performance and payment obligations of NRG PMI under the railcar lease described in Item 2. - Contractual Obligations and Commercial Commitments. Payment obligations include future rental and termination payments, which are estimated to total $58.6 million over the first five years of the lease, and $49.9 million over the last 5 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 quarter ended March 31, 2005, we issued guarantees of the performance of NRG PMI under various agreements with counter-parties for the purchase and sale of fuel, emission credits and power generation products. These new guarantees total $17.8 million. At this time, we do not believe we will be obligated to perform under these guarantees.

At March 31, 2005, we were contingently obligated for approximately $173.2 million under our funded standby letters of credit facility, and we had $16.1 million issued under an unfunded standby letter of credit facility. Obligations of the unfunded letter of credit facility were reserved through our bankruptcy restructuring. Most of these standby letters of credit are issued in support of our obligations to perform under commodity agreements, financing or other arrangements. These letters of credit expire within one year of issuance, and it is typical for us to renew many of them on similar terms.

On April 1, 2005, in conjunction with the sale of our interest in the Enfield Energy Center Ltd, a minority-owned, indirectly held affiliate of ours, we issued a guarantee of the obligations of a subsidiary of ours under the sale and purchase agreement, to the buyers of our interest. The maximum liability for this guarantee is estimated to be approximately $55.4 million, subject to adjustments. 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 14 — Condensed Consolidating Financial Information

As of March 31, 2005, we have $1.35 billion of 8% Second Priority Senior Secured Notes outstanding. These notes are guaranteed by each of our current and future wholly-owned domestic subsidiaries, or Guarantor Subsidiaries. Each of the following Guarantor Subsidiaries fully and unconditionally guarantee the Notes.

Arthur Kill Power LLC
Astoria Gas Turbine Power LLC
Berrians I Gas Turbine Power LLC
Big Cajun II Unit 4 LLC
Capistrano Cogeneration Company
Chickahominy River Energy Corp.
Commonwealth Atlantic Power LLC
Conemaugh Power LLC
Connecticut Jet Power LLC
Devon Power LLC
Dunkirk Power LLC
Eastern Sierra Energy Company
El Segundo Power II LLC
Hanover Energy Company
Huntley Power LLC
Indian River Operations Inc.
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

Indian River Power LLC
James River Power LLC
Kaufman Cogen LP
Keystone Power LLC
Louisiana Generating LLC
Middletown Power LLC
Montville Power LLC
NEO California Power LLC
NEO Chester-Gen LLC
NEO Corporation
NEO Freehold-Gen LLC
NEO Landfill Gas Holdings Inc.
NEO Power Services Inc.
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 North Central Operations Inc.
NRG Northeast Affiliate Services Inc.
NRG Northeast Generating LLC
NRG Norwalk Harbor Operations Inc.
NRG Operating Services, Inc.
NRG Oswego Harbor Power Operations Inc.
NRG Power Marketing Inc.
NRG Rocky Road LLC
NRG Saguaro Operations Inc.
NRG South Central Affiliate Services Inc.
NRG South Central Generating LLC
NRG South Central Operations Inc.
NRG West Coast LLC
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 Energy, the Guarantor Subsidiaries and the Non-Guarantor Subsidiaries in accordance with Rule 3-10 under the Securities and Exchange Commission’s Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the Guarantor Subsidiaries or Non-Guarantor Subsidiaries operated as independent entities.

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2005

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$ 451,593	$ 138,176	$ 12,807	$ (1,434)	$ 601,142
Operating Costs and Expenses					
Cost of majority-owned operations	338,448	106,965	8,943	(1,434)	452,922
Depreciation and amortization	33,276	12,839	2,309	—	48,424
General, administrative and development	10,538	8,667	30,689	—	49,894
Other charges					
Corporate relocation charges	—	—	3,455	—	3,455
Reorganization items	27	—	(27)	—	—
Total operating costs and expenses	382,289	128,471	45,369	(1,434)	554,695
Operating Income/(Loss)	69,304	9,705	(32,562)	—	46,447
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	(474)	—	—	(474)
Equity in earnings of consolidated subsidiaries	45,197	—	79,200	(124,397)	—
Equity in earnings of unconsolidated affiliates	6,981	29,964	19	—	36,964
Other income, net	585	22,172	2,806	(61)	25,502
Refinancing expenses	—	9,783	(34,807)	—	(25,024)
Interest expense	(121)	(16,252)	(39,679)	61	(55,991)
Total other income/(expense)	52,642	45,193	7,539	(124,397)	(19,023)
Income From Continuing Operations Before Income Taxes	121,946	54,898	(25,023)	(124,397)	27,424
Income Tax Expense/(Benefit)	45,508	6,935	(47,641)	—	4,802
Income/(Loss) From Continuing Operations	76,438	47,963	22,618	(124,397)	22,622
Loss on Discontinued Operations, net of Income Taxes	—	(4)	—	—	(4)
Net Income/(Loss)	$ 76,438	$ 47,959	$ 22,618	$ (124,397)	$ 22,618

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

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEETS
March 31, 2005

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ 131,781	$ 303,374	$ 327,870	$ —	$ 763,025
Restricted cash	3,737	74,522	—	—	78,259
Accounts receivable-trade, net	134,075	80,548	14,769	—	229,392
Accounts receivable – affiliates	(24,236)	177,788	(153,081)	32	503
Current portion of notes receivable — affiliates	(222)	232	38,884	(38,894)	—
Current portion of notes receivable	—	26,560	300	—	26,860
Income taxes receivable	1	(7,851)	44,500	—	36,650
Inventory	177,631	29,687	1,439	—	208,757
Derivative instruments valuation	22,899	12,297	—	—	35,196
Prepayments and other current assets	225,401	23,888	45,000	(140)	294,149
Deferred income taxes	113,937	(113)	(113,938)	1,137	1,023
Current assets — discontinued operations	(88)	3,107	—	—	3,019
Total current assets	784,916	724,039	205,743	(37,865)	1,676,833
Property, Plant and Equipment					
In service	2,362,577	1,158,386	41,756	—	3,562,719
Under construction	28,541	(6,893)	2,757	196	24,601
Total property, plant and equipment	2,391,118	1,151,493	44,513	196	3,587,320
Less accumulated depreciation	(172,637)	(66,342)	(15,907)	—	(254,886)
Net property, plant and equipment	2,218,481	1,085,151	28,606	196	3,332,434
Other Assets					
Investment in subsidiaries	799,922	—	4,006,843	(4,806,765)	—
Equity investments in affiliates	333,979	419,811	450	—	754,240
Notes receivable, less current portion -affiliates, net	403,387	118,059	—	(403,165)	118,281
Notes receivable and other investments, less current portion, net	1,533	648,327	977	—	650,837
Intangible assets, net	253,460	31,449	—	—	284,909
Debt issuance costs, net	—	1,301	39,506	—	40,807
Derivative instruments valuation	257	17,405	6,802	—	24,464
Deposits	—	—	350,000	—	350,000
Other assets	36,436	18,990	5,067	—	60,493
Total other assets	1,828,974	1,255,342	4,409,645	(5,209,930)	2,284,031
Total Assets	$4,832,371	$ 3,064,532	$ 4,643,995	$ (5,247,600)	$7,293,298
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt	$ 17	$ 80,575	$ 4,500	$ —	$ 85,092
Current portion of long-term debt — affiliates	32,000	6,894	—	(38,894)	—
Accounts payable — trade	37,002	88,464	4,275	—	129,741
Accounts payable — affiliates	140,759	10,919	(151,679)	1	—
Accrued property, sales and other taxes	3,688	8,632	1,288	—	13,608
Accrued salaries, benefits and related costs	13,077	5,502	5,202	—	23,781
Accrued interest	362	9,932	34,421	(140)	44,575
Derivative instruments valuation	107,408	16,334	—	—	123,742
Other bankruptcy settlement	—	177,425	—	—	177,425
Other current liabilities	81,176	24,155	42,390	—	147,721
Current liabilities — discontinued operations	—	1,374	—	—	1,374
Total current liabilities	415,489	430,206	(59,603)	(39,033)	747,059
Other Liabilities					
Long-term debt	197	1,033,027	2,110,145	—	3,143,369
Long-term debt — affiliates	(350)	403,515	—	(403,165)	—
Deferred income taxes	54,498	121,891	(54,471)	1,137	123,055
Postretirement and other benefit obligations	102,703	8,113	(1,062)	—	109,754
Derivative instruments valuation	30,563	106,055	21,840	—	158,458
Other long-term obligations	336,333	40,468	17,055	—	393,856
Non-current liabilities — discontinued operations	—	1,081	—	—	1,081
Total non-current liabilities	523,944	1,714,150	2,093,507	(402,028)	3,929,573
Total Liabilities	939,433	2,144,356	2,033,904	(441,061)	4,676,632
Minority Interest	—	6,576	—	—	6,576
Stockholders' Equity	3,892,938	913,600	2,610,090	(4,806,538)	2,610,090
Total Liabilities and Stockholders' Equity	$4,832,371	$ 3,064,532	$ 4,643,994	$ (5,247,599)	$7,293,298

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

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2005

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income/(loss)	$ 76,438	$ 47,959	$ 22,618	$ (124,397)	$ 22,618
Adjustments to reconcile net income to net cash provided by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates and consolidated subsidiaries	(51,751)	(25,463)	77,661	(32,443)	(31,996)
Depreciation and amortization	33,275	12,839	2,309	—	48,423
Reserve for note and interest receivable	—	(98)	—	—	(98)
Amortization of financing costs and debt discount	—	1,414	930	—	2,344
Write-off of deferred financing costs and debt premium	—	(9,783)	1,370	—	(8,413)
Deferred income taxes and investment tax credits	(27,320)	(1,981)	23,753	—	(5,548)
Unrealized (gains)/losses on derivatives	76,047	10,808	(83,295)	81,522	85,082
Minority interest	—	474	—	—	474
Amortization of power contracts and emission credits	8,179	2,974	—	—	11,153
Amortization of unearned equity compensation	686	80	1,298	—	2,064
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions					
Accounts receivable	48,265	1,006	(7,765)	—	41,506
Inventory	40,021	(343)	22	—	39,700
Prepayments and other current assets	(121,510)	9,999	(2,107)	(10,931)	(124,549)
Accounts payable	(32,917)	(1,966)	(818)	—	(35,701)
Accounts payable – affiliates	75,986	(14,489)	10,995	(81,522)	(9,030)
Accrued expenses	3,392	(5,277)	9,637	10,931	18,683
Other current liabilities	(25,687)	9,233	13,972	—	(2,482)
Other assets and liabilities	(10,885)	20,291	205	—	9,611
Net Cash Provided (Used) by Operating Activities	92,219	57,677	70,785	(156,840)	63,841
Cash Flows from Investing Activities					
Decrease/(increase) in restricted cash and trust funds	(17)	34,342	—	—	34,325
Decrease/(increase) in notes receivable	4,000	56,504	(33,402)	41,100	68,202
Capital expenditures	(8,198)	(3,449)	(135)	—	(11,782)
Return of capital from equity investments	—	1,095	—	—	1,095
Net Cash Provided (Used) by Investing Activities	(4,215)	88,492	(33,537)	41,100	91,840
Cash Flows from Financing Activities					
Proceeds from issuance of long-term debt	37,986	206,660	(1)	(41,100)	203,545
Payments for dividends	(150,000)	(6,840)	(3,872)	156,840	(3,872)
Deferred debt issuance costs	—	(1,077)	(216)	—	(1,293)
Payment for preferred share issuance cost	—	—	(53)	—	(53)
Principal payments on short and long-term debt	(4)	(281,976)	(416,963)	—	(698,943)
Net Cash Provided (Used) by Financing Activities	(112,018)	(83,233)	(421,105)	115,740	(500,616)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	(2,033)	—	—	(2,033)
Change in Cash from Discontinued Operations	—	(52)	—	—	(52)
Net Increase (Decrease) in Cash and Cash Equivalents	(24,014)	60,851	(383,857)	—	(347,020)
Cash and Cash Equivalents at Beginning of Period	155,795	242,523	711,727	—	1,110,045
Cash and Cash Equivalents at End of Period	$ 131,781	$ 303,374	$ 327,870	$ —	$ 763,025

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

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATING STATEMENTS OF OPERATIONS
For the Three Months Ended March 31, 2004

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$ 426,496	$ 163,434	$ 12,007	$ (1,672)	$ 600,265
Operating Costs and Expenses					
Cost of majority-owned operations	271,987	103,774	7,664	(1,672)	381,753
Depreciation and amortization	34,895	17,419	2,692	—	55,006
General, administrative and development	19,822	2,969	13,587	14	36,392
Other charges					
Corporate relocation charges	—	—	1,116	—	1,116
Reorganization items	1,733	150	4,367	—	6,250
Total operating costs and expenses	328,437	124,312	29,426	(1,658)	480,517
Operating Income/(Loss)	98,059	39,122	(17,419)	(14)	119,748
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	(508)	—	—	(508)
Equity in earnings of consolidated subsidiaries	21,586	—	57,829	(79,415)	—
Equity in earnings of unconsolidated affiliates	7,728	10,810	(825)	—	17,713
Write downs and losses on sales of equity method investments	—	(1,973)	235	—	(1,738)
Other income, net	702	7,449	778	(5,272)	3,657
Refinancing expenses	—	—	(30,417)	—	(30,417)
Interest expense	714	(25,440)	(43,289)	5,286	(62,729)
Total other income/(expense)	30,730	(9,662)	(15,689)	(79,401)	(74,022)
Income/(Loss) From Continuing Operations Before Income Taxes	128,789	29,460	(33,108)	(79,415)	45,726
Income Tax Expense/(Benefit)	70,967	6,656	(63,343)	—	14,280
Income From Continuing Operations	57,822	22,804	30,235	(79,415)	31,446
Loss from Discontinued Operations, net of Income Taxes	(72)	(1,139)	—	—	(1,211)
Net Income/(Loss)	$ 57,750	$ 21,665	$ 30,235	$ (79,415)	$ 30,235

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

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATING BALANCE SHEETS
December 31, 2004

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ 155,795	$ 242,523	$ 711,727	$ —	$ 1,110,045
Restricted cash	3,720	109,104	—	—	112,824
Accounts receivable-trade, net	182,340	82,757	7,004	—	272,101
Current portion of notes receivable and other investments – affiliates	—	(2,986)	5,482	(2,496)	—
Current portion of notes receivable and other investments	—	85,147	300	—	85,447
Taxes receivable	1	(5,498)	42,981	—	37,484
Inventory	216,932	29,617	1,461	—	248,010
Derivative instruments valuation	79,759	—	—	—	79,759
Prepayments and other current assets	103,891	25,740	42,893	(2,916)	169,608
Current assets — discontinued operations	(88)	3,098	—	—	3,010
Total current assets	742,350	569,502	811,848	(5,412)	2,118,288
Property, Plant and Equipment					
In service	2,359,090	1,163,986	41,582	—	3,564,658
Under construction	24,481	(10,044)	2,796	196	17,429
Total property, plant and equipment	2,383,571	1,153,942	44,378	196	3,582,087
Less accumulated depreciation	(140,013)	(53,925)	(13,598)	—	(207,536)
Net property, plant and equipment	2,243,558	1,100,017	30,780	196	3,374,551
Other Assets					
Investment in subsidiaries	776,922	—	3,916,352	(4,693,274)	—
Equity investments in affiliates	327,425	407,054	471	—	734,950
Notes receivable and other investments, less current portion — affiliates	407,165	363,462	—	(642,581)	128,046
Notes receivable and other investments, less current portion	1,533	673,966	977	—	676,476
Intangible assets, net	256,392	37,958	—	—	294,350
Debt issuance costs, net	—	247	48,238	—	48,485
Derivative instruments valuation	1,468	34,926	5,393	—	41,787
Funded letter of credit	—	—	350,000	—	350,000
Other assets	36,406	21,596	5,093	—	63,095
Total other assets	1,807,311	1,539,209	4,326,524	(5,335,855)	2,337,189
Total Assets	$4,793,219	$ 3,208,728	$ 5,169,152	$ (5,341,071)	$ 7,830,028
LIABILITIES AND STOCK HOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt	$ 16	$ 98,877	$ 415,855	$ (2,496)	$ 512,252
Accounts payable — trade	69,919	91,119	5,093	—	166,131
Accounts payable — affiliate	333,514	(129,041)	(199,799)	917	5,591
Accrued property, sales and other taxes	1,841	8,188	1,105	—	11,134
Accrued salaries, benefits and related costs	15,723	6,493	12,990	—	35,206
Accrued interest	435	6,000	7,538	(2,916)	11,057
Derivative instruments valuation	16,772	—	—	—	16,772
Current deferred income taxes	260	92	(18)	—	334
Other bankruptcy settlement	—	175,576	—	—	175,576
Other current liabilities	106,863	17,245	28,418	—	152,526
Current liabilities — discontinued operations	—	1,362	—	—	1,362
Total current liabilities	545,343	275,911	253,615	(4,495)	1,087,941
Other Liabilities					
Long-term debt	202	1,768,068	2,128,177	(642,581)	3,253,866
Deferred income taxes	(32,379)	130,972	35,732	—	134,325
Postretirement and other benefit obligations	98,439	8,987	8,957	—	116,383
Derivative instruments valuation	172	132,209	16,064	—	148,445
Other long-term obligations	341,960	30,883	16,876	—	389,719
Non-current liabilities — discontinued operations	—	1,081	—	—	1,081
Total non-current liabilities	408,394	2,072,200	2,205,806	(642,581)	4,043,819
Total liabilities	953,737	2,348,111	2,476,988	(647,076)	5,131,760
Minority interest	—	6,104	—	—	6,104
Stockholders' Equity	3,839,482	854,513	2,692,164	(4,693,995)	2,692,164
Total Liabilities and Stockholders' Equity	$4,793,219	$ 3,208,728	$ 5,169,152	$ (5,341,071)	$ 7,830,028

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

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATING STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2004

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income	$ 57,750	$ 21,664	$ 30,235	$ (79,414)	$ 30,235
Adjustments to reconcile net income to net cash provided by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates	2,115	(5,002)	(26,819)	49,415	19,709
Depreciation and amortization	34,895	21,527	2,692	—	59,114
Amortization of financing costs and debt discount	—	7,524	1,719	—	9,243
Write off of deferred financing cost and debt premium	—	—	15,312	—	15,312
Write down and loss on sale of equity investments	—	1,973	(235)		1,738
Deferred income taxes and investment tax credits	(110,818)	(15,866)	211,185	(72,553)	11,948
Unrealized (gains)/losses on derivatives	1,482	(34,047)	(8,251)	35,423	(5,393)
Minority interest	—	1,428	—	—	1,428
Amortization of out of market power contracts and emission credits	8,589	14,158	—	—	22,747
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions					
Accounts receivable, net	(16,981)	(12,594)	(99)	—	(29,674)
Xcel Energy settlement receivable	—	—	288,000	—	288,000
Inventory	20,304	735	(4)	—	21,035
Prepayments and other current assets	(25,026)	(36,492)	59,564	31,747	29,793
Accounts payable	86,353	46,636	(114,752)	(20,215)	(1,978)
Accrued expenses	(5,887)	50,396	39,139	(43,119)	40,529
Other current liabilities	18,184	(2,614)	(17,180)	(4,800)	(6,410)
Creditor pool obligation payments	—	—	(163,000)	—	(163,000)
Other assets and liabilities	2,850	5,957	3,349	(6,377)	5,779
Net Cash Provided by Operating Activities	73,810	65,383	320,855	(109,893)	350,155
Cash Flows from Investing Activities					
Investments in subsidiaries	—	—	(92,000)	92,000	—
Proceeds from the sale of investments	—	—	2,500	—	2,500
Decrease/(increase) in restricted cash and trust funds	3,640	(21,354)	—	—	(17,714)
Decrease/(increase) in notes receivable	(83,612)	14,214	(10,129)	95,467	15,940
Capital expenditures	(29,831)	(4,588)	(309)	—	(34,728)
Investments in projects	(476)	—	—	—	(476)
Net Cash Used by Investing Activities	(110,279)	(11,728)	(99,938)	187,467	(34,478)
Cash Flows from Financing Activities					
Capital contributions from parent	92,000	—	—	(92,000)	—
Payment of dividends to NRG Energy, Inc.	(30,000)	—	—	30,000	—
Proceeds from issuance of long-term debt	6,799	—	494,803	(15,574)	486,028
Deferred debt issuance costs	—	53	(7,286)	—	(7,233)
Principal payments on short and long-term debt	(335)	(11,336)	(505,241)	—	(516,912)
Net Cash Provided (Used) by Financing Activities	68,464	(11,283)	(17,724)	(77,574)	(38,117)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	(401)	—	—	(401)
Change in Cash from Discontinued Operations	—	3,098	—	—	3,098
Net Increase in Cash and Cash Equivalents	31,995	45,069	203,193	—	280,257
Cash and Cash Equivalents at Beginning of Period	295,509	160,434	95,280	—	551,223
Cash and Cash Equivalents at End of Period	$ 327,504	$ 205,503	$ 298,473	$ —	$ 831,480

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

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

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

Overview

NRG Energy, Inc., or "NRG Energy", the "Company", "we", "our", or "us", is a wholesale power generation company, primarily engaged in the ownership and operation of power generation facilities, the transacting in and trading of fuel and transportation services and the marketing and trading of energy, capacity and related products in the United States and internationally. We have a diverse portfolio of electric generation facilities in terms of geography, fuel type and dispatch levels. Our principal domestic generation assets consist of a diversified mix of natural gas-, coal- and oil-fired facilities, representing approximately 40%, 31% and 29% of our total domestic generation capacity, respectively. In addition, 23% of our domestic generating facilities have dual- or multiple-fuel capacity, which may allow 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 serve the requirements of the load-serving entities in our core markets. 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 or for alternative use, among other reasons. Our business also may involve acquisitions intended to complement the asset portfolios in our core regions, and from time to time we may also consider and undertake other merger and acquisition transactions that are consistent with our strategy.

The wholesale energy industry entered a prolonged slump in 2001, from which it is only beginning to emerge. We expect that generally weak market conditions will continue for the foreseeable future in many U.S. markets. We further expect that the merchant power industry will continue to experience corporate restructuring, debt restructuring, and consolidation over the coming years.

We seek to maximize operating income through the generation of energy, marketing and trading of energy, capacity and ancillary services into spot, intermediate and long-term markets and the effective transacting in and trading of fuel supplies and transportation-related services. We perform our own power marketing (except with respect to our West Coast Power and Rocky Road affiliates), which is focused on maximizing the value of our North American and Australian assets through the pursuit of asset-focused power and fuel marketing and, trading activities in the spot, intermediate and long-term markets. We also seek to manage and mitigate commodity market risk, reduce cash flow volatility over time, realize the full market value of the asset base, and add incremental value by using market knowledge to effectively trade positions associated with our asset portfolio. Additionally, we work with independent system operators, regional transmission organizations, regulators and other 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 March 31, 2005, we owned interests in 51 power projects in five countries having an aggregate net generation capacity of approximately 15,151 MW. Approximately 7,900 MW of our capacity consists of merchant 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 March 31, 2005, our assets in the West Coast 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 right for the facility's generating capacity. The agreement is subject to the amendment of the El Segundo RMR agreement to switch to RMR Condition I and to otherwise allow the purchaser to exercise its primary dispatch rights under this agreement while preserving Cal ISO's ability to call on the El Segundo facility as a reliability resource under the RMR agreement, if necessary. Approximately 265 MW of capacity at the Long Beach generating facility was retired January 1, 2005.

We own approximately 1,600 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 2,100 MW in various international markets, including Australia, Europe 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.

Asset Sales. We have substantially completed our divestment of major non-core assets; however, as part of our strategy, we plan to continue the selective divestment of certain non-core assets. We have no current plans to market actively any of our core assets, although our intention to maximize over time the value of all of our assets could lead to additional asset sales.

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 pending final disposition. Accounting regulations require that continuing operations be reported separately in the income statement from discontinued operations, and that any gain or loss on the disposition of any such business be reported along with the operating results of such business. Assets classified as discontinued operations on our balance sheet as of March 31, 2005 consist of the McClain project. NRG McClain was sold in July 2004 however certain assets and liabilities remain to effect its liquidation. Discontinued results of operations for the three months ended March 31, 2005 consist of various expenses related to NRG McClain to effect its liquidation. For the three months ended March 31, 2004, discontinued results of operations include McClain, PERC, Cobee, Hsin Yu, LSP Energy (Batesville) and several NEO Corporation projects. All discontinued operations were sold prior to December 31, 2004.

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 and safety requirements could have a material effect on our operations or competitive position.

On March 15, 2005, the US Environmental Protection Authority, or USEPA, issued the Clean Air Mercury Rule, or CAMR, to permanently cap and reduce mercury emissions from coal-fired power plants. CAMR imposes limits on mercury emissions from new and existing coal-fired plants and creates a market-based cap-and-trade program that will reduce nationwide utility emissions of mercury in two phases (2010 and 2018). Consistent with the significant debate on whether USEPA has authority to regulate mercury emissions through a cap-and-trade mechanism (as opposed to a command-and-control requirement to install "maximum achievable control technology", or MACT, on a unit basis), ten states, together with certain environmental organizations, have sued the federal government over CAMR. The states (including California, Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New Mexico, New York, Vermont and Wisconsin) allege that the rule violates the Clean Air Act (CAA) because it fails to treat mercury as a hazardous air pollutant. Each of our coal-fired electric power plants will be subject to mercury regulation. However, since the final rule has yet to be implemented by individual states, it is not possible to identify in detail how the final mercury rules will affect our operations located in those states. Nevertheless, we continue to actively review emerging mercury monitoring and mitigation technologies and assess appropriate options for the Company.

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, when CAMR was released the nickel MACT provisions were omitted on the basis of the USEPA's reconsideration of the requirement for new controls on nickel emissions from oil-fired generators.

On March 10, 2005, the USEPA announced the Clean Air Interstate Rule, or CAIR. This rule applies to 28 eastern states and the District of Columbia and caps SO_2 and NO_X emissions from power plants in two phases (2010 and 2015 for SO_2 and 2009 and 2015 for NO_X). CAIR will apply to certain of the Company's power plants in New York, Massachusetts, Connecticut, Delaware and Louisiana. States must achieve the required emission reductions through: (a) requiring power plants to participate in a USEPA-administered interstate cap-and-trade system; or (b) measures to be selected by individual states. While the Company's current business plans include initiatives to address emissions (for example, the conversion of Huntley and Dunkirk to burn low sulfur coal), until the final rule as issued by USEPA is actually implemented by specific state legislation, it is not possible to identify with greater specificity the effect of CAIR on the Company.

In 2004, USEPA re-proposed the Regional Haze Rule, designed to improve air quality in national parks and wilderness areas. This rule requires regional haze controls (by targeting SO_2 and NO_X emissions from sources including power plants) through the installation of Best Available Retrofit Technology, or BART, for certain sources. While the so-called BART rule had been expected to be finalized in April 2005, a two month extension has been agreed, with USEPA amendments expected by June 15, 2005, together with rules for associated trading programs by November 2005. It is likely that the BART rule, if implemented, will affect many of the Company's facilities, although it is also expected that actions taken for compliance with CAIR and certain state initiatives will satisfy the current BART rule.

Federal legislation has been proposed that would impose annual caps on U.S. power plant emissions of NO_X, 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 have filed suit against USEPA asking the Court to address whether USEPA has an existing obligation to regulate GHGs under the Clean Air Act (CAA). Oral arguments in the case were scheduled for April 8, 2005 and this matter is still in process. Further, eight states and the City of New York filed suit in 2004 against American Electric Power Company, Southern Company, Tennessee Valley Authority, Xcel Energy, Inc. and Cinergy Corporation, alleged to be the nation's five largest emitters of GHGs and all of which are owners of electric generation. In the latter case, an injunction is sought against each defendant to force it to abate its contribution to the "global warming nuisance" by requiring it to cap its CO_2 emissions and then reduce them by a specified percentage each year for at least a decade. The outcome of GHG-related litigation and proposed legislation cannot be predicted. The Company's compliance costs with any mandated GHG reductions in the future could be material.

Nine northeastern states have created a regional initiative to establish a cap-and-trade GHG program for electric generators, referred to as the Regional Greenhouse Gas Initiative, or RGGI. The model RGGI rule is to be announced in late Spring or Summer 2005, with an estimate of two to three years for participating states to finalize implementing regulations. A proposed level of the RGGI cap has not been determined at this time. If implemented, our plants in New York, Delaware, Massachusetts, and Connecticut may be materially affected.

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

The Ozone Transport Commission, or OTC, was established by Congress and governs ozone and the NO_X budget program in certain eastern states, including Massachusetts, Connecticut, New York and Delaware. In January 2005, the OTC stepped up its efforts to develop a multi-pollutant regime (SO_2, NO_X, mercury and CO_2) that is expected to be completed by mid-2006 (with individual state implementation to follow). 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 seeks to effect emissions requirements that are more stringent than currently proposed or 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 federal Acid Rain Program starting in January 2008). In addition, under ADRP generators now also have to meet the ozone season NO_X 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 12 to the Financial Statements. 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 in New York (including under the recent settlement) through the end of the decade.

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 the facilities over the years. As a result, USEPA and several states filed suits against a number of coal-fired power plants in mid-western and southern states alleging violations of the CAA New Source Review (NSR) requirements. One of the more prominent suits of this type, involving Ohio Edison, announced an agreement on March 18, 2005 which settles NSR issues with respect to 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 is still expected by summer 2005. In the meantime, the USEPA's proposed NSR rule from October 2003 is still pending review.

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 12 to the Financial Statements.

Regulatory Developments

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

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 will decide the issue in a litigated proceeding before an administrative law judge ("ALJ"). Under the proposal, separate capacity markets would be created for distinct areas of New England, including southwest Connecticut and the rest of the state of Connecticut. While we view this proposal as a positive development, as it is currently proposed it would not permit us to recover all of our fixed costs. In response, we have submitted testimony which includes an alternative proposal. The trial before the ALJ ended in early April 2005, and NRG and other participants in the case filed post-hearing briefs on April 15, 2005. Reply briefs are due on April 29, 2005. FERC's goal is to issue a decision on the precise terms of the NEPOOL LICAP market in the fall of 2005, so that the LICAP market can be implemented on January 1, 2006.

New York

In April 2003, NYISO implemented a demand curve in its capacity market and scarcity pricing improvements in its energy market. The New York demand curve eliminated the previous market structure's tendency to price capacity at either its cap (deficiency rate) or near zero. FERC had previously approved the demand curve, but on December 19, 2003, the Electricity Consumers Resource Council ("ELCON") appealed the FERC decision to the United States Court of Appeals for the District of Columbia Circuit. On December 3, 2004, NRG Energy and other suppliers filed a brief in opposition. On April 11, 2005, the central parties to the ELCON case argued their positions before the court of appeals. An adverse decision by the Court of Appeals could require the elimination of the demand curve for the capacity market, and would negatively impact the development of LICAP in New England and PJM in addition to New York.

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. It is anticipated that the capacity prices for the New York state excluding New York City and Long Island will probably increase by $1 per KW-year. The FERC's modifications should also increase the capacity prices in New York City but the existing In-City mitigation measures will prevent us from obtaining these higher prices.

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

South Central

Entergy has filed an Independent Coordinator of Transmission proposal at FERC and with the public service commissions of the states of Louisiana, Mississippi and Arkansas. Entergy states that this proposal will achieve greater oversight of its transmission system operation and provide greater efficiency for providing and pricing transmission service. On March 22, 2005 FERC approved Entergy's ICT proposal for a two year period, subject to certain conditions. On April 21, 2005, NRG and other generators and municipalities filed a motion for rehearing, claiming that the ICT is not sufficiently independent and that the FERC was in error in approving Entergy's transmission pricing proposal, even for a two year period. Also on April 21, 2005 Entergy notified FERC that it accepted the March 22, 2005 order subject to certain conditions and that it would make a filing with the FERC on or about May 27, 2005 to implement the ICT proposal.

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 March 25, 2005, FERC permitted Entergy's proposal to reserve 2,900 MWs of import capacity for emergency purposes to go into effect, subject to refund. On April 19, 2005, Entergy and the other parties to the case agreed that there would not be any import capacity reserved for emergencies.

West Coast

The Cal ISO projects a southern California peak load shortage this summer of nearly 2,000 MW. The warnings from the Cal ISO 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 CPUC now requires that load-serving entities meet a 15-17% reserve margin by June 2006. This has prompted RFOs from load-serving entities, with the stated goal of engaging in bilateral contract negotiations with the merchant generators to secure their long term capacity needs. They must demonstrate that they have secured at least 90% of their capacity needs by June 2005. This will, in effect, create a de facto capacity market that should reflect the long term marginal cost of new generation. It is possible that such a capacity market will also reward generation located in transmission constrained areas within load pockets, such as El Segundo and possibly Long Beach.

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

Australian Region

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

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

On 14 March 2005, a black out occurred in the South Australian region of the NEM, triggered by a transmission fault. The National Electricity Code Administrator (NECA), the regulatory body currently responsible for the enforcement of the market rules, is conducting an investigation into these events. NRG is assisting in the investigation, but at this time cannot opine on the eventual outcome of the investigation.

RESULTS OF OPERATIONS

The following tables provide selected financial information by segment for the three months ended March 31, 2005 and 2004:

	For the three months ended March 31, 2005						
	Northeast	South Central	West Coast	Other North America	Australia	All Other	Total
				(In thousands)			
Energy revenue	$276,548	$ 68,883	$ 163	$ 4,960	$ 31,829	$ 19,792	$402,175
Capacity revenue	64,833	45,276	—	2,404	—	21,461	133,974
Alternative revenue	16	—	—	728	—	48,156	48,900
O & M fees	—	—	—	—	—	4,664	4,664
Other revenues	(8,937)	2,987	12	(2,945)	16,957	3,355	11,429
Operating revenues	332,460	117,146	175	5,147	48,786	97,428	601,142
Fuel costs	185,153	66,460	360	1,484	22,630	49,138	325,225
Other operating expenses *	94,962	23,915	1,076	7,667	22,138	27,833	177,591
Depreciation and amortization	18,609	15,142	198	1,993	6,594	5,888	48,424
Operating income/(loss)	33,732	11,629	(1,459)	(5,997)	(2,576)	11,118	46,447

	For the three months ended March 31, 2004						
	Northeast	South Central	West Coast	Other North America	Australia	All Other	Total
				(In thousands)			
Energy revenue	$257,636	$ 46,387	$ 1,204	$ 5,289	$ 54,062	$ 18,329	$382,907
Capacity revenue	58,770	45,327	(3,709)	17,112	—	21,131	138,631
Alternative revenue	5	—	—	655	—	45,468	46,128
O & M fees	—	—	(2)	214	—	5,373	5,585
Other revenues	14,129	3,551	(815)	(2,435)	8,167	4,417	27,014
Operating revenues	330,540	95,265	(3,322)	20,835	62,229	94,718	600,265
Fuel costs	146,035	48,090	118	1,776	23,462	46,199	265,680
Other operating expenses *	79,066	15,848	1,592	9,174	17,074	29,711	152,465
Depreciation and amortization	18,529	16,962	202	7,610	5,125	6,578	55,006
Operating income/(loss)	86,590	13,642	(5,234)	2,125	16,569	6,056	119,748

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

Management’s discussion of our results of operations for the three months ended March 31, 2005 and 2004

Net Income

For the three months ended March 31, 2005, we recorded net income of $22.6 million, or $0.21 per diluted weighted average share of common stock compared to net income of $30.2 million or $0.30 per diluted weighted average share of common stock for the three months ended March 31, 2004. Unseasonably mild weather in January and February characterized the first quarter of 2005 and kept spark spreads in the Northeast compressed. Though absolute gas prices were 14% higher than first quarter last year resulting in higher power prices, due to increasing fuel costs, our overall realized oil spark spreads and coal dark spreads were compressed versus the first quarter last year. Higher generation from our domestic operations helped to offset the compressed spreads, with total generation for the quarter 4% higher than first quarter last year. Additionally, we recorded $39.5 million of net unrealized losses associated with forward sales of electricity supporting our Northeast assets. During the latter part of 2004 and early 2005, we hedged much of 2005 Northeast generation. Since that time, and through March 31, 2005, gas prices continued to rise. While this benefited our portfolio versus last year with higher power prices and increased gas prices, with the forward curve at a high point at quarter end we were required to mark-to-market recognition of these forward sales. First quarter 2005 results were also unfavorably impacted by an unseasonably mild summer in Australia, which resulted in weak pool prices versus the first quarter of 2004 when Australia experienced unseasonably warm weather.

Net income results were favorably impacted by lower interest expense and higher other income and higher equity earnings for the quarter. In December 2004, we refinanced our Senior Credit Facility, decreasing our interest expense by 212.5 basis points as compared to the facility in place during the first quarter of 2004. This, combined with the lower outstanding debt reduced interest expense. Other income for the quarter was favorable versus the first quarter 2004 by $21.8 million, primarily due to reaching settlement on the TermoRio note receivable, resulting in a $13.5 million gain, and a recorded $3.5 million in other income related to a contingent purchase price adjustment received for a previously sold project, the Crockett Cogeneration Facility. Additionally, equity earnings for the first quarter 2005 were favorably impacted by approximately $12 million mark-to-market gain associated with our Enfield investment. In the first quarter 2004, the Enfield investment recorded a $1 million loss. These favorable results were offset by higher operating expenses versus last quarter due to the increased number of more extensive planned outages for the year versus last year. Additionally, G&A expenses adversely impacted results versus last year due to increased audit fees, Sarbanes Oxley compliance and a number of one-time credits recorded last year.

Revenues from Majority-Owned Operations

Revenues from majority-owned operations were $601.1 million for the three months ended March 31, 2005 compared to $600.3 million for the three months ended March 31, 2004. Revenues for the three months ended March 31, 2005 included $402.2 million of energy revenues compared to $382.9 million of energy revenues for the three months ended March 31, 2004. Of the $402.2 million, 87% are merchant revenues; in the first quarter of 2004, 74% of our energy revenues were merchant. The increase in energy revenues versus 2004 were largely driven by the increased merchant generation from our New York City, South Central and Indian River facilities. Capacity revenues for the three months ended March 31, 2005 were $133.9 million compared to $138.6 million for the three months ended March 31, 2004. Capacity revenues were unfavorable versus the first quarter last year due to the loss of capacity revenues from the Kendall facility, which was sold in the fourth quarter of 2004, and the addition of new generation and increased imports in New York, which depressed capacity prices for our assets in the Western New York market. This loss was partially offset by $23.9 million additional capacity revenues during the quarter related to our Connecticut RMR settlement agreement which was approved by FERC on January 22, 2005. Alternative revenues and O&M fees for the three months ended March 31, 2005 were $48.9 million and $4.7 million, respectively. This compares to $46.1 million of alternative energy revenues and $5.6 million of O&M fees in the first quarter of 2004. Other revenues include derivative and financial revenues, natural gas sales, Fresh Start Contract amortization, and expense recovery revenues. For the three months ended March 31, 2005, other revenues totaled $11.4 million compared to $27 million of other revenues for the three months ended March 31, 2004. Other revenues were positively impacted by less contract amortization in 2005 versus 2004 as contracts have rolled off over the course of 2004 and gains from financial hedges relative to the first quarter of 2004. This is offset, however, by the net $39.5 million in mark-to-market losses we recorded this quarter, as compared to the $1 million in unrealized losses in the first quarter of 2004.

Cost of Majority-Owned Operations

Cost of majority-owned operations for the three months ended March 31, 2005 was $452.9 million or 75% of revenues from majority-owned operations. Cost of majority-owned operations for the three months ended March 31, 2004 was $381.8 million or 63.6% of revenues from majority-owned operations. Cost of majority-owned operations consists of the cost of energy (primarily fuel costs), operating labor, operating and maintenance costs and non-income based taxes. Cost of energy for the first quarter of 2005 was $325.2 versus $265.7 million for the first quarter of 2004. Higher coal, gas, and oil prices from our domestic operations were the primary drivers of the increased fuel costs. Fuel costs for our Northeast and South Central operations increased by $51.3 million, $45.4 million of which was driven by price increases. An increase of 4% in our generation from our domestic operations was a secondary contributing factor.

Operating and maintenance costs for the first quarter 2005 totaled $111.6 million versus $97.5 million in the first quarter of 2004. This increase is driven by the increase in major maintenance projects and more extensive outages in 2005, as compared to 2004. The low-sulfur coal conversion of the Western New York plants and Indian River plant is a main focus for many of the major maintenance and outages in 2005; the conversion projects were not in progress during the first quarter of 2004.

Depreciation and Amortization

Our depreciation and amortization expense for the three months ended March 31, 2005 and 2004 was $48.4 million and $55.0 million, respectively. Depreciation and amortization consists primarily of the allocation of our historical depreciable fixed asset costs over the remaining lives of such property. The decrease in depreciation and amortization from 2005 to 2004 is primarily due to the 2004 sale of our Kendall plant, which had recorded $5.5 million in depreciation and amortization expense in the first quarter of 2004.

General, Administrative and Development

Our general, administrative and development costs for the three months ended March 31, 2005 were $49.9 million or 8.3% of operating revenue compared to $36.4 million or 6.1% of operating revenue for the three months ended March 31, 2004. These amounts include corporate costs of $25.5 million, or 4.2% of operating revenues, for the first quarter of 2005, as compared to $16.3 million, or 2.7% of operating revenues, for the first quarter of 2004. General, administrative and development 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. General, administrative and development costs have been adversely impacted by increased costs associated with increased audit fees, insurance costs and increased consulting costs related to Sarbanes Oxley compliance for our 2004 year-end audit.

Corporate Relocation Charges

During the three months ended March 31, 2005, we recorded $3.5 million for charges related to our corporate relocation activities as compared to $1.1 million for the prior year's corresponding period. Included in the first quarter 2005 charge is $2.8 million related to the lease abandonment charges associated with our former Minneapolis office, with $0.7 million primarily related to the relocation, recruitment and transition costs. In 2004, we recorded $1.1 million for charges primarily related to employee severance and termination benefits.

Equity in Earnings of Unconsolidated Affiliates

During the three months ended March 31, 2005, we recorded $37 million of equity earnings from our investments in unconsolidated affiliates as compared to $17.7 million for the three months ended March 31, 2004. Our investment in West Coast Power comprised $4.1 million for the first quarter of 2005 as compared to $6 million for the first quarter of 2004. However, during 2004, our equity earnings in the project as reported were reduced by a net $27.2 million primarily related to non-cash Fresh Start basis adjustments due to the California Department of Water Resources (CDWR) contract. The CDWR contract expired December 31, 2004, which is the primary driver for the change in equity earnings from first quarter 2004 to first quarter 2005. Equity earnings for our Enfield investment was $16 million for the first quarter of 2005 versus $0.8 million in the first quarter of 2004. First quarter 2005 results for Enfield included approximately $12 million of unrealized gain associated with changes in the fair value of energy-related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

Other equity investments included in the 2005 results are Mibrag and Gladstone, comprising $7.4 million and $6.1 million, respectively. During the three months ended March 31, 2004, we recorded earnings of $6.3 million for Mibrag and $3.2 million for Gladstone.

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

As part of our periodic review of our equity method investments for impairments, we have taken write downs and losses on sales of equity method investments for the three months ended March 31, 2004 of $1.7 million. We did not incur any write downs or losses on equity method investments for the three months ended March 31, 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 pretax proceeds of $59.5 million. A pre-tax gain of approximately $6.0 million will be recorded upon completion of the sale. Additionally, we expect to receive an additional amount of approximately $4.0 million based upon the post-closing working capital adjustment, which will also be recorded as a pre-tax gain on sale when the cash is received.

Other income, net

During the three months ended March 31, 2005 and 2004, we recorded $25.5 million and $3.6 million, respectively, of other income, net. Other income in 2005 was favorably impacted by a $13.5 million gain from the settlement related to our TermoRio project in Brazil. Additionally, during the first quarter of 2005, we realized 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 higher interest income earned on notes receivable and higher average cash balances.

Refinancing expense

Refinancing expense for the three months ended March 31, 2005 and 2004 was $25 million and $30.4 million, respectively. In the first quarter 2005, we redeemed and purchased a total of $416 million of our Second Priority Notes. As a result of the redemption and purchases, we recorded a total of $34.8 million in fees, and write-offs of deferred financing costs and premiums received from the bond issuance, and premium fees we paid for the redeemed and purchased bonds. Additionally, our Australia region refinanced their project debt during the first quarter 2005. As a result of this refinancing, we recorded a credit of $9.8 million reflecting the write-off of debt premium.

In the first quarter ended March 31, 2004, we refinanced certain amounts of our term loans with additional corporate level high yield notes. Related to this transaction, we recorded $15.1 million of prepayment penalties and $15.3 million of write-off of deferred financing costs.

Interest expense

Interest expense for the three months ended March 31, 2005 was $55.9 million as compared to $62.7 million, for the three months ended March 31, 2004. Interest expense was favorably impacted by the sale of Kendall in the fourth quarter of 2004. Kendall incurred $6.6 million of interest expense in the first quarter of 2004. Additionally, due to refinancing of our Senior Debt whereby we lowered our interest rate by 212.5 basis points and due to the $416 million redemption and purchases of our Second Priority Notes during the first quarter, interest expense on our corporate debt was reduced by approximately $3 million. These favorable impacts were offset by the addition of $2.6 million interest expense associated with our Itiquira project’s debt. Interest expense consists of both our project and corporate level interest bearing debt. Also included in interest expense is the amortization of debt financing costs and the amortization expense related to debt discounts and premiums recorded as part of Fresh Start. Additionally, interest expense includes the impact of any interest rate swaps that we have entered in order to manage our exposure to changes in interest rates.

Income Tax Expense

Income tax expense was $4.8 million and $14.3 million for the three months ended March 31, 2005 and 2004, respectively. The overall effective tax rate was 17.5% and 31.2% for the three months ended March 31, 2005 and 2004, respectively. The effective income tax rate for the three months ended March 31, 2005 differs from the U.S. statutory rate of 35% due to the appropriation of a full valuation allowance and due to earnings in foreign jurisdictions taxed at rates lower than the U.S. statutory rate.

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.

Loss from Discontinued Operations, net of Income Taxes

We classified as discontinued operations the operations and gains/losses recognized on the sale of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. During the three months ended March 31, 2005 and 2004, we recorded a loss from discontinued operations of $4,000 and $1.2 million, respectively. Discontinued operations for the three months ended March 31, 2005 consist of various expenses related to NRG McClain to effect its liquidation. During the period ended March 31, 2004, discontinued operations consisted of the results of our NRG McClain LLC, Penobscot Energy Recovery Company, or PERC, Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee, Hsin Yu, LSP Energy (Batesville) and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha and NEO Tajiguas LLC). All discontinued operations were sold prior to December 31, 2004.

Northeast Region Results

Operating Income

For the period ending March 31, 2005, operating income for Northeast Region was $33.7 million, as compared to $86.6 million for the period ended March 31, 2004. Unseasonably mild weather during the first quarter kept spark spreads in the Northeast compressed. Though absolute gas prices were 14% higher than first quarter last year resulting in higher power prices, overall spreads were compressed for coal and oil based generating assets versus first quarter 2004. Northeast generation increased slightly over the quarter last year and helped to partially offset the compressed margins. Additionally, the Northeast recorded a net $39.5 million unrealized loss associated with forward sales of electricity supporting our Northeast assets.

Revenues

Revenues from our Northeast region totaled $332.5 million for the three months ended March 31, 2005 compared to $330.5 million for the three months ended March 31, 2004. Revenues for the three months ended March 31, 2005 included $276.6 million in energy revenues compared to $257.6 million for the three months ended March 31, 2004. These favorable results versus 2004 were largely driven by the increased generation from our New York City and Indian River facilities, as outages from other suppliers in their respective areas provided the opportunity to sell more merchant energy. Capacity revenues for the three months ended March 31, 2005 were $64.8 million compared to $58.8 million for the three months ended March 31, 2004. Capacity revenues were favorable versus the first quarter last year due to $23.9 million additional capacity revenues recorded during the quarter related to our Connecticut RMR settlement agreement which was approved by FERC on January 22, 2005. These settlement revenues were offset, however, by lower capacity revenues from our Western New York plants. Capacity prices in this region were negatively impacted by the addition of new capacity supply and increased imports into New York. Other revenues include derivative and financial revenues, natural gas sales, Fresh Start Contract amortization, and expense recovery revenues. For the three months ended March 31, 2005, other revenues totaled a loss of $8.9 million compared to $14.1 million of other revenues for the three months ended March 31, 2004. Other revenues were adversely impacted by the $39.5 million in mark-to-market unrealized losses we recorded this quarter, as compared to the $1 million in unrealized losses in the first quarter of 2004. These mark-to-market unrealized losses were partly offset by less contract amortization in 2005 versus 2004 and gains realized on hedge transactions booked to financial revenues as compared to the first quarter of 2004.

Operating Expenses

Operating expenses for our Northeast operations for the three months ended March 31, 2005 were $280.9 million or 84% of the Northeast's revenues, as compared to $225.1 million or 68% of revenues for the three months ended March 31, 2004. The increase in operating expenses is primarily driven by the increase in the cost of energy, as fuel prices and the Northeast's generation increased from the first quarter 2005 over the first quarter 2004. Fuel costs in the Northeast were $185.2 million as compared to $146 million in 2004. Oil fuel costs at our Northeast region increased by $19 million, where $12.3 million of the increase was due to increased generation. Average coal costs at our Northeast region increased by $11.1 million. Nearly all the fuel cost increase is due to the rise in coal prices, with our Indian River facility driving the overall increase. Indian River burns eastern coal which has experienced high price volatility versus western coal. As such, this plant was more adversely affected by the overall increase in coal prices. Our Indian River facility is currently undertaking a Western coal conversion to mitigate some of this price volatility exposure.

Operations and Maintenance (O&M) expenses includes operating labor, normal and major maintenance, and other operating costs. O&M for our Northeast region was $56.5 million for the first quarter 2005 as compared to $51 million in the first quarter 2004. The low-sulfur conversion projects continue at our Western New York plants and have been initiated at our Indian River plant this quarter. The low-sulfur conversion projects were not underway as of the first quarter of 2004. An increase in forced outages in the Northeast versus last year also unfavorably impacted the O&M cost. Other operating expenses for the Northeast region include the administrative regional office costs, insurance and corporate allocations. Other operating costs totaled $24.6 million for the first quarter of 2005 as compared to $14.9 million in 2004. This increase is due to the increase in the corporate allocations per our new allocation methodology as discussed in Note 9 to the Consolidated Financial Statements. Additionally, the Northeast's regional office costs were largely recorded as corporate costs in 2004.

South Central Region Results

Operating Income

For the period ending March 31, 2005, operating income for South Central Region was $11.6 million, as compared to $13.6 million for the period ended March 31, 2004. This quarter, our Big Cajun II facility experienced several forced outages which required the purchase of additional energy at higher cost to meet its contract load-following obligation in the merchant market at higher costs than our coal-based generating assets. With the higher power price environment, total generation from the South Central assets increased by 8.8% over last year, helping to offset the impacts of the outages.

Revenues

Revenues from our South Central region were $117.1 million for the three months ended March 31, 2005 compared to $95.3 million for the three months ended March 31, 2004. Revenues for the three months ended March 31, 2005 included $68.9 million in energy revenues, of which 61% were contracted. This compares to $46.4 million of energy revenues for the three months ended March 31, 2004; 79% of which were contracted. South Central energy revenues were favorably impacted by this favorable variance in contract revenues in increased merchant energy sales. Merchant energy sales were favorable versus last year due to the higher gas price environment, favorable weather, and nuclear plant outages in the region. Additionally, during the first quarter of 2004, a one-month scheduled outage resulted in less generation being available for sale in the merchant market than this year. Capacity revenues were $45.3 million in each of the three months ended March 31, 2004 and 2005. Capacity revenues are fully contracted. Other revenues include derivative and financial revenues and Fresh Start Contract amortization. For the three months ended March 31, 2005, other revenues totaled $3 million compared to $3.5 million for the three months ended March 31, 2004.

Operating Expenses

Operating expenses for our South Central region for the three months ended March 31, 2005 were $90.3 million or 77% of South Central's revenues, as compared to $63.9 million or 67% of revenues for the three months ended March 31, 2004. The increase of operating expenses is primarily driven by the increase in fuel costs. Total cost of energy in South Central was $66.5 million as compared to $48.1 million in 2004. Of this $18.4 million increase, $8.3 million is due to higher coal and transportation prices. Additionally, the cost of purchased energy increased over last quarter due to higher prices. The increase in purchased energy cost is responsible for $8.5 million of the $18.4 million increase in cost of energy. The average price of purchased energy increased by nearly $4 per megawatt hour over last year, while two forced outages required additional purchases of energy to meet contract load versus first quarter last year. O&M for our South Central region was $13.3 million for the first quarter 2005 as compared to $10 million in the first quarter 2004. The increase in O&M is related to increased major maintenance. During the first quarter 2005, South Central had two planned outages versus one major outage during the first quarter of 2004. Other operating expenses for South Central for the three months ended March 31, 2005 were $9.1 million as compared to $4.3 million for the three months ended March 31, 2004. The increase is largely due to the new NRG allocations methodology as discussed in Note 9 to the Consolidated Financial Statements. Additionally, much of the South Central regional office had been recorded as corporate costs in the first quarter of 2004.

West Coast Region Results

For the period ending March 31, 2005, the West Coast region realized an operating loss of $1.5 million, as compared to an operating loss of $5.2 million for the period ended March 31, 2004. The primary driver of the lower operating loss is related to the payment of CAISO penalties paid by our Red Bluff and Chowchilla facilities in 2004, offset by the expiration of their RMR contract as of December 31. 2004. These results do not include the equity earnings of Saguaro or West Coast Power.

Other North America Region Results

For the period ending March 31, 2005, the Other North America region realized an operating loss of $6 million on revenues of $5.2 million, as compared to operating income of $2.1 million and revenues of $20.8 million for the period ended March 31, 2004. This unfavorable variance is primarily related to the sale of Kendall. Kendall had operating income of $6.9 million and revenues of $17 million in the first quarter of 2004. Operating expenses and depreciation and amortization for our Other North America region for the three months ended March 31, 2005 were $9.2 million and $2 million respectively. For the first quarter of 2004, operating expenses and depreciation and amortization were $11 million and $7.6 million, respectively. The favorable variance in both of these is driven by the sale of Kendall, with the variance in operating expense partially offset by a bad debt allowance taken this quarter for a receivable due from a third-party. These results do not include the equity earnings of our Rocky Road investment.

Australia Region Results

Operating Income

For the period ending March 31, 2005, the Australia region realized an operating loss of $2.6 million, as compared to $16.6 million in operating income for the period ended March 31, 2004. Unseasonably mild weather drove the decrease in operating income, as weak pool prices characterized the first quarter of 2005.

Revenues

Revenues from our Australia Region totaled $48.8 million for the three months ended March 31, 2005 compared to $62.2 million for the three months ended March 31, 2004. Revenues for the three months ended March 31, 2005 included $31.8 million in energy revenues compared to $54.1 million of energy revenues for the three months ended March 31, 2004. These unfavorable results versus 2004 were largely driven by weak pool prices, partially offset by the increased generation. An unseasonably mild summer in Australia drove the average pool price down to $23.26 per megawatt hour from $40.33 per megawatt hour in the first quarter of 2004, a reduction of 42% versus the first quarter in 2004. Due to the full commercialization of the Playford station, generation for the first quarter of 2005 was 1.3 million MWh which was slightly ahead of the 1.2 million MWh generated in the first quarter of 2004. Other revenues were positively impacted by less contract amortization in 2005 versus 2004 and the positive results of our hedge transactions as financial revenues.

Operating Expenses

Operating expenses for our Australia region for the three months ended March 31, 2005 were $44.8 million or 92% of Australia's revenues, as compared to $40.5 million, or 65% of revenues, for the three months ended March 31, 2004. O&M for our Australia region increased to $19.6 million for the first quarter 2005 as compared to $16 million in the first quarter 2004. This increase was due to increased coal production costs associated with our Playford facility, which was not fully operational in the first quarter of 2004. Other operating expenses for Australia for the three months ended March 31, 2005 increased over the first quarter of 2004 due to the new NRG allocations methodology as discussed in Note 9 to the Consolidated Financial Statements.

Depreciation and amortization

Australia's depreciation and amortization expense for the three months ended March 31, 2005 and 2004 was $6.6 million and $5.1 million, respectively. The unfavorable variance is related to the additional depreciation Australia recorded in 2005 as the refurbished Playford Power Station is now fully operational.

Critical Accounting Policies and Estimates

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. 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.

Liquidity and Capital Resources

In December 2004, we issued $420.0 million of convertible preferred stock and used the proceeds from such issuance to redeem $375.0 million of the Second Priority Notes in February 2005. Also in January 2005 and in March 2005, we used existing cash to purchase, at market prices, $25.0 million and $15.8 million, respectively, in face value of our Second Priority Notes. These notes are held in treasury by NRG Energy. As of March 31, 2005 and May 3, 2005, we had $1.31 billion in aggregate principal amount of Second Priority Notes, excluding those held in treasury, $448.9 million in principal amount outstanding under the term loan and $350.0 million of the funded letter of credit facility outstanding. As of May 3, 2005, $175.2 million of undrawn letters of credit remain available under the funded letter of credit, and we had not drawn down on our revolving credit facility.

In connection with our power generation business, we manage the commodity price risk associated with our supply activities and our electric generation facilities. This includes forward power sales, fuel and energy purchases and emission credits. In order to manage these risks, we enter into financial instruments to hedge the variability in future cash flows from forecasted sales of electricity and purchases of fuel and energy. We utilize a variety of instruments including forward contracts, future contracts, swaps and options. Certain of these contracts allow counterparties to require NRG to post margin collateral. As of March 31, 2005 and May 3, 2005, we have posted $169.2 million and $136.3 million, respectively, in collateral to support these contracts.

In March 2004, we entered into two interest rate swap agreements in support of our obligations under the Second Priority Notes and the Amended Credit Facility. Depending on market interest rates, we or the swap counterparty may be required to post collateral on a daily basis in support of both of these swaps, to the benefit of the other party. On March 31, 2005 and May 3, 2005, we had posted $5.6 million and $0 in collateral.

Capital Expenditures

Capital expenditures were approximately $11.1 million and $34.7 million for the three months ended March 31, 2005 and March 31, 2004, respectively. We anticipate that our 2005 capital expenditures will be approximately $133 million and will relate to the operation and maintenance of our existing generating facilities.

Liquidity

As of March 31, 2005 our liquidity was $1.2 billion and includes $841 million of unrestricted and restricted cash. Our liquidity also includes $150.0 million of available capacity under our revolving line of credit and $176.4 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 cash and restricted cash. Our liquidity also included $150.0 million of available capacity under our revolving line of credit and $176 million of availability under our letter of credit facility.

Other Liquidity Matters – NOL's and Deferred Tax Assets

As of March 31, 2005, we have a net operating loss carryforward of $29.5 million which will expire through 2024. We believe that it is more likely than not that benefit will not be realized on the deferred tax assets relating to the net operating loss carryforwards. This assessment included consideration of positive and negative factors, including our current financial position and results of operations, projected future taxable income, including projected operating and capital gains, and available tax planning strategies. Therefore, as of March 31, 2005, a valuation allowance of $736 million was recorded against the net deferred tax assets, including net operating loss carryforwards in accordance with SFAS No. 109.

Cash Flows

	For the Three Months Ended	
	March 31, 2005	March 31, 2004
	(In thousands)	
Net cash provided by operating activities	$ 63,841	$ 350,155
Net cash provided/(used) by investing activities	91,840	(34,478)
Net cash used in financing activities	(500,616)	(38,117)

Net Cash Provided By Operating Activities

For the three months ended March 31, 2005, cash provided by operating activities was $64.8 million, a decrease of $286.9 million from the three months ended March 31, 2004. The decrease was primarily driven by a net $125 million increase in the first quarter of

2004 related to a net bankruptcy-related receivable and payable and the 2005 increase in prepayments and other current assets of $124.5 million. The increase in prepayments is due largely to cash collateral needed for trading activities by our Power Marketing group. Additionally, lower net income contributed to the reduction in cash provided by operating activities.

Net Cash Provided/(Used) By Investing Activities

For the three months ended March 31, 2005, cash provided by investing activities was $91.8 million compared to a use of cash for investing activities of $34.5 million for the same period last year. The decrease in notes receivable contributed $68.0 million, primarily from the receipt of payment from TermoRio. Other contributing factors included our reduction in restricted cash of $34.3 million primarily at Flinders. This reduction in restricted cash at Flinders is due to the refinancing of their debt and the corresponding lift of restrictions to cash balances.

Net Cash Used in Financing Activities

For the three months ended March 31, 2005, cash used by financing activities was $500.6 million consisting of the redemption and repurchase of our long-term debt. During the first quarter of 2005, we repurchased $415.8 million of our second priority secured notes and prepaid $47.2 million of our debt at Flinders. For the three months ended March 31, 2004, cash used by financing activities was $38.1 million. In January of 2004, we received proceeds through a supplementary note offering whereby we issued an additional $475.0 million of Second Priority Notes at a premium. We used the proceeds from this offering to repay $503.5 million of our then recently issued term loan.

Off-Balance Sheet Arrangements

As of March 31, 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 $247.8 million and $251.7 million as of March 31, 2005 and December 31, 2004, respectively. In the normal course of business we may be asked to loan funds to unconsolidated affiliates on both a long and short-term basis. Such transactions are generally accounted for as accounts payable and receivable to/from affiliates and notes payable/receivable to/from affiliates and if appropriate, bear market-based interest rates.

Contractual Obligations and Commercial Commitments

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

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

In December 2004, we entered into a long-term coal transport agreement with the Burlington Northern and Santa Fe Railway Company and affiliates of American Commercial Lines LLC to deliver low sulfur coal to our Big Cajun II facility in New Roads, Louisiana beginning April 1, 2005. In March 2005, we entered into an agreement to purchase coal over a period of four years and nine months from Buckskin Mining Company, or Buckskin. The coal will be sourced from Buckskin's mine in the Powder River Basin, Wyoming, and will be used primarily in NRG Energy's coal-burning generation plants in the South Central region of the United States. Including this contract and other contracts, total coal purchase obligations increased by $160.1 million.

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.

Derivative Instruments

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 March 31, 2005 based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at March 31, 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	(52,665)
Changes in fair value	(126,204)
Fair value of contracts at March 31, 2005	$ (222,540)

Sources of Fair Value Gains/(Losses)

	Fair Value of Contracts at Period End as of March 31, 2005				
	Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in excess of 5 Years	Total Fair Value
			(In thousands)		
Prices actively quoted	$ (62,674)	$ (27,547)	$ —	$ —	$ (90,221)
Prices based on models and other valuation methods	(3,961)	(25,344)	(16,481)	(30,984)	(76,770)
Prices provided by other external sources	(21,047)	(7,835)	(5,896)	(20,771)	(55,549)
Total	$ (87,682)	$ (60,726)	$ (22,377)	$ (51,755)	$ (222,540)

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.

Changes in Accounting Standards

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

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

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 ending March 31, 2005	$ 21.8
Average	21.1
High	32.6
Low	16.1
Year end 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 March 31, 2005 is $21.8 million.

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

Interest Rate Risk

We are exposed to fluctuations in interest rates through our issuance of fixed rate and variable rate debt. Exposures to interest rate fluctuations may be mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to interest rate volatility and result in primarily fixed rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. Our risk management policy allows us to reduce interest rate exposure from variable rate debt obligations.

As of March 31, 2005, we had various interest rate swap agreements with notional amounts totaling approximately $1.6 billion. If the swaps had been discontinued on March 31, 2005, we would have owed the counter-parties approximately $37.7 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 March 31, 2005, a 100 basis point change in interest rates would result in a $5.0 million change in interest expense.

At March 31, 2005, the fair value of our long-term debt was $3.3 billion, compared with the carrying amount of $3.2 billion. We estimate that a 1% decrease in market interest rates would have increased the fair value of our long-term debt by $61.1 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, British Pound and the Brazilian Real. We have historically engaged in a strategy of hedging foreign denominated cash flows through a program of matching currency inflows and outflows, and to the extent required, fixing the U.S. Dollar equivalent of net foreign denominated distributions with currency forward and swap agreements with highly credit worthy financial institutions. We would expect to enter into similar transactions in the future if management believes it to be appropriate.

As of March 31, 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 March 31, 2005, we held collateral support of $176.9 million from counter-parties.

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

Significant Customers

For the three months ended March 31, 2005, we derived approximately 44.8% of our total revenues from majority-owned operations from two customers: NYISO accounted for 30.1% and ISO New England accounted for 14.7%. 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 control areas.

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 (the " Exchange Act"). 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.

Notwithstanding the foregoing and 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 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 March 31, 2005, see Note 12 "Commitments and Contingencies" to our consolidated financial statements contained in Part I, Item 1 of this Form 10-Q.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

None.

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.

Cautionary Statement Regarding Forward Looking Information

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

- Our ability to successfully and timely close transactions to sell certain of our assets;
- Hazards customary to the power production industry and power generation operations such as fuel and electricity price volatility, unusual weather conditions, catastrophic weather-related or other damage to facilities, unscheduled generation outages, maintenance or repairs, unanticipated changes to fossil fuel supply costs or availability due to higher demand, shortages, transportation problems or other developments, environmental incidents, or electric transmission or gas pipeline system constraints and the possibility that we may not have adequate insurance to cover losses as a result of such hazards;
- Our potential inability to enter into contracts to sell power and procure fuel on terms and prices acceptable to us;
- The liquidity and competitiveness of wholesale markets for energy commodities;
- Changes in government regulation, including possible changes of market rules, market structures and design, rates, tariffs, environmental laws and regulations and regulatory compliance requirements;
- Price mitigation strategies and other market structures or designs employed by independent system operators, or ISOs, or regional transmission organizations, or RTOs, that result in a failure to adequately compensate our generation units for all of their costs;
- Our ability to borrow additional funds and access capital markets, as well as our substantial indebtedness and the possibility that we may incur additional indebtedness going forward; and

- 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.

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: May 10, 2005

Exhibit Index

Exhibits

31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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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: May 10, 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: May 10, 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: May 10, 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 March 31, 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: May 10, 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.