UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q/A

Amendment No. 1

☒ **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 Quarter Ended: June 30, 2004 **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.)
901 Marquette Avenue, Suite 2300 **Minneapolis, Minnesota** (Address of principal executive offices)	**55402** (Zip Code)

(612) 373-5300
(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 October 29, 2004, there were 100,008,053 shares of common stock outstanding.

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EXPLANATORY NOTE

In connection with the registration of our 8% Second Priority Senior Notes due December 15, 2013 issued on December 17, 2003 and January 28, 2004, we are reissuing our quarterly report for the quarter ended June 30, 2004 as amendment No. 1 on Form 10-Q/A. The updated information includes consolidating financial statements as required by Rule 3-10 of Regulation S-X as described in Note 22. In addition, we have attached to this Form 10-Q/A as exhibits 99.1 through 99.8 the unaudited quarterly financial statements of eight significant guarantor subsidiaries as required by Rule 3-16 of Regulation S-X.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Reorganized NRG	Predecessor Company	Reorganized NRG	Predecessor Company
	Three Months Ended		Six Months Ended	
	June 30, 2004	June 30, 2003	June 30, 2004	June 30, 2003
	(In thousands, except for per share amounts)			
Operating Revenues				
Revenues from majority-owned operations	**$ 573,674**	$ 441,599	**$1,173,992**	$ 936,609
Operating Costs and Expenses				
Cost of majority-owned operations	**353,750**	381,845	**735,801**	759,432
Depreciation and amortization	**53,168**	63,768	**108,174**	122,906
General, administrative and development	**45,837**	39,147	**82,329**	87,663
Corporate relocation charges	**5,645**	—	**6,761**	—
Reorganization items	**(2,661)**	6,334	**3,589**	6,334
Restructuring and impairment charges	**1,676**	269,631	**1,676**	291,767
Total operating costs and expenses	**457,415**	760,725	**938,330**	1,268,102
Operating Income/(Loss)	**116,259**	(319,126)	**235,662**	(331,493)
Other Income (Expense)				
Minority interest in earnings of consolidated subsidiaries	**(201)**	—	**(709)**	—
Equity in earnings of unconsolidated affiliates	**46,101**	46,857	**63,814**	92,486
Write downs and gains/(losses) on sales of equity method investments	**1,205**	(132,436)	**(533)**	(149,027)
Other income, net	**8,052**	(7,953)	**11,708**	3,542
Interest expense	**(66,225)**	(92,087)	**(159,371)**	(260,761)
Total other expense	**(11,068)**	(185,619)	**(85,091)**	(313,760)
Income/(Loss) From Continuing Operations Before Income Taxes	**105,191**	(504,745)	**150,571**	(645,253)
Income Tax Expense	**36,322**	4,305	**50,602**	37,342
Income/(Loss) From Continuing Operations	**68,869**	(509,050)	**99,969**	(682,595)
Income/(Loss) on Discontinued Operations, net of Income Taxes	**14,155**	(99,351)	**13,290**	61,562
Net Income/(Loss)	**$ 83,024**	$(608,401)	**$ 113,259**	$ (621,033)
Weighted Average Number of Common Shares Outstanding — Basic	**100,080**		**100,051**	
Income From Continuing Operations per Weighted Average Common Share — Basic	**$ 0.69**		**$ 1.00**	
Income From Discontinued Operations per Weighted Average Common Share — Basic	**0.14**		**0.13**	
Net Income per Weighted Average Common Share — Basic	**$ 0.83**		**$ 1.13**	
Weighted Average Number of Common Shares Outstanding — Diluted	**100,478**		**100,214**	
Income From Continuing Operations per Weighted Average Common Share — Diluted	**$ 0.69**		**$ 1.00**	
Income From Discontinued Operations per Weighted Average Common Share — Diluted	**0.14**		**0.13**	
Net Income per Weighted Average Common Share — Diluted	**$ 0.83**		**$ 1.13**	

See notes to consolidated financial statements.

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (REORGANIZED COMPANY)

(Unaudited)

	June 30, 2004	December 31, 2003
	(In thousands)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 820,876	$ 551,223
Restricted cash	151,673	116,067
Accounts receivable — trade, less allowance for doubtful accounts of $322 and $0	313,649	201,921
Xcel Energy settlement receivable	—	640,000
Current portion of notes receivable — affiliates	1,917	200
Current portion of notes receivable	123,060	65,141
Taxes receivable	14,824	—
Inventory	203,672	194,926
Derivative instruments valuation	11,670	772
Prepayments and other current assets	229,961	222,178
Current deferred income taxes	961	1,850
Current assets — discontinued operations	56,955	119,561
Total current assets	1,929,218	2,113,839
Property, Plant and Equipment		
In service	3,935,915	3,885,465
Under construction	104,794	139,171
Total property, plant and equipment	4,040,709	4,024,636
Less accumulated depreciation	(119,487)	(11,800)
Net property, plant and equipment	3,921,222	4,012,836
Other Assets		
Equity investments in affiliates	677,684	737,998
Notes receivable, less current portion — affiliates	122,539	130,152
Notes receivable, less current portion	612,118	691,444
Intangible assets, net of accumulated amortization of $34,404 and $5,212	356,068	432,361
Debt issuance costs, net of accumulated amortization of $4,992 and $454	63,038	74,337
Derivative instruments valuation	53,474	59,907
Funded letter of credit	250,000	250,000
Other assets	116,129	123,145
Non-current assets — discontinued operations	451,785	618,968
Total other assets	2,702,835	3,118,312
Total Assets	$8,553,275	$9,244,987

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (REORGANIZED COMPANY)
(Unaudited)

	June 30, 2004	December 31, 2003
	(In thousands)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 96,385	$ 801,229
Short-term debt	17,826	19,019
Accounts payable — trade	137,033	158,683
Accounts payable — affiliates	6,372	7,053
Accrued taxes	—	16,095
Accrued property, sales and other taxes	16,136	22,322
Accrued salaries, benefits and related costs	33,072	19,331
Accrued interest	20,038	8,982
Derivative instruments valuation	20,979	429
Creditor pool obligation	25,000	540,000
Other bankruptcy settlement	221,283	220,000
Other current liabilities	113,773	102,861
Current liabilities — discontinued operations	23,121	110,177
Total current liabilities	731,018	2,026,181
Other Liabilities		
Long-term debt and capital leases	3,922,417	3,327,782
Deferred income taxes	144,522	149,493
Postretirement and other benefit obligations	110,842	105,946
Derivative instruments valuation	159,567	153,503
Other long-term obligations	473,247	480,938
Non-current liabilities — discontinued operations	469,911	558,884
Total non-current liabilities	5,280,506	4,776,546
Total Liabilities	6,011,524	6,802,727
Minority Interest	5,673	5,004
Commitments and Contingencies		
Stockholders' Equity		
Serial Preferred Stock; 10,000,000 shares authorized, none issued and outstanding at June 30, 2004 and December 31, 2003	—	—
Common stock; $.01 par value; 500,000,000 shares authorized; 100,006,798 shares at June 30, 2004 and 100,000,000 shares at December 31, 2003 issued and outstanding	1,000	1,000
Additional paid-in capital	2,410,751	2,403,429
Retained earnings	124,284	11,025
Accumulated other comprehensive income	43	21,802
Total stockholders' equity	2,536,078	2,437,256
Total Liabilities and Stockholders' Equity	$8,553,275	$9,244,987

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY/(DEFICIT)

Three Months Ended June 30, 2004 and June 30, 2003
(Unaudited)

(In thousands)	Common Stock	Common Shares	Additional Paid-in Capital	Retained Earnings/ (Accumulated Deficit)	Accumulated Other Comprehensive Income/(Loss)	Total Stockholders' Equity/(Deficit)
Balances at March 31, 2003 (Predecessor Company)	$ —	—	$2,227,692	$ (2,841,565)	$ (139,004)	$ (752,877)
Net loss				(608,401)		(608,401)
Foreign currency translation adjustments and other					77,777	77,777
Deferred unrealized gain on derivatives, net					5,155	5,155
Comprehensive loss for the three months ended June 30, 2003						(525,469)
Balances at June 30, 2003 (Predecessor Company)	$ —	—	$2,227,692	$ (3,449,966)	$ (56,072)	$ (1,278,346)
Balances at March 31, 2004 (Reorganized NRG)	**$1,000**	**100,000**	**$2,406,771**	**$ 41,260**	**$ (3,176)**	**$ 2,445,855**
Net income				**83,024**		**83,024**
Foreign currency translation adjustments and other					**(33,520)**	**(33,520)**
Deferred unrealized gain on derivatives, net					**36,739**	**36,739**
Comprehensive income for the three months ended June 30, 2004						**86,243**
Equity based compensation		**7**	**3,980**			**3,980**
Balances at June 30, 2004 (Reorganized NRG)	**$1,000**	**100,007**	**$2,410,751**	**$ 124,284**	**$ 43**	**$ 2,536,078**

See notes to consolidated financial statements.

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY/(DEFICIT)
Six Months Ended June 30, 2004 and June 30, 2003
(Unaudited)

(In thousands)	Common Stock	Common Shares	Additional Paid-in Capital	Retained Earnings/ (Accumulated Deficit)	Accumulated Other Comprehensive Income/(Loss)	Total Stockholders' Equity/(Deficit)
Balances at December 31, 2002 (Predecessor Company)	$ —	—	$2,227,692	$ (2,828,933)	$ (94,958)	$ (696,199)
Net loss				(621,033)		(621,033)
Foreign currency translation adjustments and other					90,867	90,867
Deferred unrealized loss on derivatives, net					(51,981)	(51,981)
Comprehensive loss for the six months ended June 30, 2003						(582,147)
Balances at June 30, 2003 (Predecessor Company)	$ —	—	$2,227,692	$ (3,449,966)	$ (56,072)	$ (1,278,346)
Balances at December 31, 2003 (Reorganized NRG)	**$1,000**	**100,000**	**$2,403,429**	**$ 11,025**	**$ 21,802**	**$ 2,437,256**
Net income				**113,259**		**113,259**
Foreign currency translation adjustments and other					**(35,933)**	**(35,933)**
Deferred unrealized gain on derivatives, net					**14,174**	**14,174**
Comprehensive income for the six months ended June 30, 2004						**91,500**
Equity based compensation		**7**	**7,322**			**7,322**
Balances at June 30, 2004 (Reorganized NRG)	**$1,000**	**100,007**	**$2,410,751**	**$ 124,284**	**$ 43**	**$ 2,536,078**

See notes to consolidated financial statements.

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Reorganized NRG	Predecessor Company
	Six Months Ended June 30,	
(In thousands)	2004	2003
Cash Flows from Operating Activities		
Net income/(loss)	$ 113,259	$(621,033)
Adjustments to reconcile net income/(loss) to net cash provided (used) by operating activities		
Distributions in excess of (less than) equity in earnings of unconsolidated affiliates	4,751	(23,943)
Depreciation and amortization	113,499	145,221
Amortization of debt issuance costs	20,060	11,090
Amortization of debt discount	11,795	—
Deferred income taxes	49,384	36,525
Minority interest	2,089	466
Unrealized (gains)/losses on derivatives	(21,458)	17,796
Asset impairment	1,676	347,913
Write downs and losses on sales of equity method investments	533	148,841
Gain on sale of discontinued operations	(13,012)	(218,536)
Amortization of power contracts and emission credits	34,517	—
Cash provided (used) by changes in certain working capital items, net of acquisition affects		
Accounts receivable	(111,054)	(43,608)
Xcel Energy settlement receivable	640,000	—
Accrued taxes	(29,285)	(18,603)
Inventory	(8,439)	13,550
Prepayments and other current assets	(2,065)	(74,262)
Accounts payable	(27,626)	264,106
Accounts payable — affiliates	213	4,788
Accrued property, sales and other taxes	(7,065)	5,398
Accrued salaries, benefits and related costs	20,192	(3,769)
Accrued interest	14,883	126,578
Other current liabilities	(506,368)	(117,355)
Cash used by changes in other assets and liabilities	16,878	22,869
Net Cash Provided by Operating Activities	317,357	24,032
Cash Flows from Investing Activities		
Proceeds on sale of equity method investments	29,693	89,223
Proceeds on sale of discontinued operations	59,190	—
Investments in equity method investments and projects	(566)	(369)
Decrease in notes receivable, net	15,208	9,405
Capital expenditures	(64,676)	(56,605)
Increase in restricted cash and trust funds	(37,291)	(14,137)
Net Cash Provided by Investing Activities	1,558	27,517
Cash Flows from Financing Activities		
Proceeds from issuance of long-term debt, net	490,631	5,342
Deferred debt issuance costs	(8,497)	(7,474)
Principal payments on short and long-term debt	(567,806)	(31,390)
Net Cash Used by Financing Activities	(85,672)	(33,522)
Change in Cash from Discontinued Operations	10,822	24,062
Effect of Exchange Rate Changes on Cash and Cash Equivalents	25,588	(93,163)
Net Increase (Decrease) in Cash and Cash Equivalents	269,653	(51,074)
Cash and Cash Equivalents at Beginning of Period	551,223	360,860
Cash and Cash Equivalents at End of Period	$ 820,876	$ 309,786

See notes to consolidated financial statements.

NRG ENERGY, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Note 1 — Organization

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 and the sale 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. We seek to maximize operating income through the efficient procurement and management of fuel supplies and maintenance services, and the sale of energy, capacity and ancillary services into attractive spot, intermediate and long-term markets.

On May 14, 2003, we and 25 of our direct and indirect wholly owned subsidiaries commenced voluntary petitions under chapter 11 of the bankruptcy code in the United States Bankruptcy Court for the Southern District of New York. On November 24, 2003, the bankruptcy court entered an order confirming a plan of reorganization, for NRG Energy and four of our subsidiaries, and the plan became effective on December 5, 2003. On November 25, 2003, the bankruptcy court entered an order confirming the plan of reorganization for 21 of our subsidiaries, and the plan became effective on December 23, 2003. As of June 30, 2004, three entities remain in bankruptcy.

As part of the NRG plan of reorganization, Xcel Energy, Inc., or Xcel Energy, relinquished its ownership interest in us and we became an independent public company upon our emergence from bankruptcy on December 5, 2003. We no longer have any material affiliation or relationship with Xcel Energy. As part of that reorganization, we eliminated approximately $5.2 billion of corporate level bank and bond debt and approximately $1.3 billion of additional claims and disputes by distributing a combination of equity and up to $1.04 billion in cash among our unsecured creditors. In addition to the debt reduction associated with the restructuring, we used a substantial portion of the proceeds of a recent note offering and borrowings under a new credit facility to retire approximately $1.7 billion of project-level debt on December 23, 2003. In January 2004, we used proceeds of an additional note offering to repay $503.5 million of the outstanding borrowings under our new credit facility.

As of June 30, 2004, we owned interests in 55 power projects in five countries having an aggregate net generation capacity of approximately 18,000 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 also own approximately 2,500 MW of capacity in the South Central region of the United States, with approximately 1,700 MW of that capacity supported by long-term power purchase agreements. Our assets in the West Coast region of the United States consist of approximately 1,300 MW of capacity with the majority of such capacity owned via our 50% interest in West Coast Power LLC. Our assets in the west coast region are supported by a power purchase agreement with the California Department of Water Resources that runs through December 2004. One-year term "reliability must-run contracts" with the California Independent System Operator for approximately 600 MW in the San Diego area are expected to be renewed for 2005.

Our principal domestic generation assets consisted of a diversified mix of natural gas-, coal- and oil-fired facilities, representing approximately 48%, 26% and 26% of our total domestic generation capacity, respectively. In addition, 45% of our generating facilities have some capability to combust duel fuels. 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 perform our own power marketing through our energy marketing subsidiary, NRG Power Marketing, Inc., or PMI, which, is focused on maximizing the value of our North American assets by providing management services, and through the efficient procurement and management of fuel and the sale of energy and related products in the spot, intermediate and long-term markets. West Coast Power has arranged for power marketing and fuel management with affiliates of our other partner, Dynegy, Inc. 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 headquarters and principal executive offices are located at 901 Marquette Avenue, Suite 2300, Minneapolis, Minnesota, 55402. Our telephone number is (612) 373-5300. Our Internet website is http://www.nrgenergy.com. Our recent annual reports, quarterly reports, current reports and other periodic filings are available free of charge through our Internet website.

Note 2 — Summary of Significant Accounting Policies

Basis of Presentation

As used in this Quarterly Report, Predecessor Company refers to the Company prior to its emergence from bankruptcy. Reorganized NRG refers to the Company after its emergence from bankruptcy.

Between May 14, 2003 and December 5, 2003, we operated as a debtor in possession under the supervision of the Bankruptcy Court. Our financial statements for reporting periods within that timeframe were prepared in accordance with the provisions of AICPA Statement of Position 90-7, *"Financial Reporting by Entities in Reorganization Under the Bankruptcy Code",* or SOP 90-7.

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 footnotes 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, 2003. 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 June 30, 2004, the results of our operations and stockholders' equity/(deficit) for the three and six months ended June 30, 2004 and 2003, and our cash flows for the six months ended June 30, 2004 and 2003. Certain prior-year amounts have been reclassified for comparative purposes.

In connection with our emergence from bankruptcy, we adopted Fresh Start Reporting on December 5, 2003, in accordance with the requirements of SOP 90-7. The application of SOP 90-7 resulted in the creation of a new reporting entity. Under Fresh Start, our reorganization value was allocated to our assets and liabilities on a basis substantially consistent with purchase accounting in accordance with Statement of Financial Accounting Standards, or SFAS No. 141, *"Business Combinations."*

Comparability of Financial Information

Due to the adoption of Fresh Start as of December 5, 2003, the Reorganized NRG Energy balance sheet, statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are not comparable in certain respects to the financial statements prior to the application of Fresh Start. A black line has been drawn on the accompanying Consolidated Financial Statements to separate and distinguish between Reorganized NRG Energy and the Predecessor Company.

Note 3 — Discontinued Operations

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) on 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.

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. For the three and six months ended June 30, 2004, discontinued operations included our NRG McClain LLC; Penobscot Energy Recovery Company, or PERC; Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee; Hsin Yu and LSP Energy projects. For the three and six months ended June 30, 2003, discontinued operations included our NRG McClain, PERC, Cobee, Killingholme, NEO Landfill Gas, Inc., or NLGI; three NEO Corporation projects (NEO Fort Smith LLC, NEO Woodville LLC, NEO Phoenix LLC), Timber Energy Resources, Inc., or TERI; Cahua and Energia Pacasmayo, Hsin Yu and LSP Energy projects. Summarized results of operations of discontinued operations were as follows:

	Reorganized NRG Three Months Ended June 30, 2004	Predecessor Company Three Months Ended June 30, 2003	Reorganized NRG Six Months Ended June 30, 2004	Predecessor Company Six Months Ended June 30, 2003
	(In thousands)			
Operating revenues	**$ 43,257**	$ 60,590	**$ 102,080**	$ 136,377
Operating and other expenses	**40,996**	156,608	**99,702**	261,756
Pretax income/(loss) from operations of discontinued components	**2,261**	(96,018)	**2,378**	(125,379)
Income tax expense	**4**	1,267	**986**	1,787
Income/(loss) from operations of discontinued components	**2,257**	(97,285)	**1,392**	(127,166)
Disposal of discontinued components — pre-tax gain/(loss), net	**13,307**	(2,066)	**13,307**	188,728
Income tax expense	**1,409**	—	**1,409**	—
Disposal of discontinued components — gain/(loss), net	**11,898**	(2,066)	**11,898**	188,728
Income/(loss) on discontinued operations, net of income taxes	**$ 14,155**	$ (99,351)	**$ 13,290**	$ 61,562

The assets and liabilities of the discontinued operations are reported in the balance sheets as of June 30, 2004 and December 31, 2003 as discontinued operations. The major classes of assets and liabilities are presented by geographic area in the following table. As of June 30, 2004, within our Power Generation Segment, the NRG McClain and LSP Energy projects are included in the Other North America classification; all other projects have been sold as of June 30, 2004. As of December 31, 2003, within our Power Generation segment, the PERC, NRG McClain and LSP Energy projects are included in the Other North America classification and the Cobee and Hsin Yu projects are included in the Other International classification.

June 30, 2004	Power Generation Other North America
	(In thousands)
Cash	$ 1,736
Restricted cash	40,255
Receivables, net	8,181
Inventory	5,366
Prepaids and other current assets	1,417
Current assets — discontinued operations	$ 56,955
PP&E, net	$ 439,017
Other non-current assets	12,768
Non-current assets — discontinued operations	$ 451,785
Current portion of long-term debt	$ 5,448
Accounts payable — trade	2,284
Accrued liabilities	15,239
Other current liabilities	150
Current liabilities — discontinued operations	$ 23,121
Long-term debt	$ 287,279
Other non-current liabilities	182,632
Non-current liabilities — discontinued operations	$ 469,911

December 31, 2003	Power Generation Other North America	Power Generation Other International	Total
		(In thousands)	
Cash	$ 4,294	$ 8,264	$ 12,558
Restricted cash	60,292	—	60,292
Receivables, net	12,675	11,272	23,947
Inventory	8,722	3,537	12,259
Prepaids and other current assets	3,732	6,786	10,518
Current assets — discontinued operations	$ 89,715	$ 29,859	$119,574
PP&E, net	$ 487,752	$ 75,251	$563,003
Non-current deferred tax asset	—	31,469	31,469
Other non-current assets	14,765	9,731	24,496
Non-current assets — discontinued operations	$ 502,517	$ 116,451	$618,968
Current portion of long-term debt	$ 6,206	$ 49,743	$ 55,949
Accounts payable — trade	3,056	23,050	26,106
Accrued liabilities	15,292	3,981	19,273
Other current liabilities	6,139	2,723	8,862
Current liabilities — discontinued operations	$ 30,693	$ 79,497	$110,190
Long-term debt	$ 313,739	$ 19,779	$333,518
Minority interest	31,879	406	32,285
Other non-current liabilities	184,970	8,111	193,081
Non-current liabilities — discontinued operations	$ 530,588	$ 28,296	$558,884

NRG McClain — On July 9, 2004, NRG McClain completed the sale of its 77% interest in the McClain Generating Station to Oklahoma Gas & Electric Company. The Oklahoma Municipal Power Authority will continue to own the remaining 23% interest in the facility. The proceeds of $160.2 million from the sale will be used to repay outstanding project debt under the secured term loan and working capital facility. A loss of $3.2 million was recognized as of June 30, 2004 based upon the final terms of the sale.

PERC — During the first quarter of 2004, we received board authorization to proceed with the sale of our interest in PERC to SET PERC Investment LLC that reached financial closing in April 2004. Upon completion of the transaction, we received net proceeds of $18.4 million, resulting in a gain of $2.0 million, net of tax.

Cobee — During the first quarter of 2004, we entered into an agreement for the sale of our interest in our Cobee project to Globeleq Holdings Limited, which reached financial closing in April 2004. Upon completion of the transaction, we received net proceeds of approximately $50.0 million, resulting in a gain of $2.8 million.

LSP Energy — In May 2004 we reached an agreement to sell our 100 percent interest in an 837-megawatt generating plant in Batesville, Mississippi to Complete Energy Partners LLC. We expect to realize cash proceeds of $26.5 million, subject to certain purchase price adjustments and transaction costs. A gain of approximately $16.0 million is expected upon completion of the sale.

Hsin Yu —During the second quarter of 2004, we entered into an agreement for the sale of our interest in our Hsin Yu project to a minority interest shareholder, Asia Pacific Energy Development Company Ltd., which reached financial closing in May 2004. Upon completion of the transaction, we received net proceeds of $1.0 million, resulting in a gain of approximately $10.3 million, resulting from our negative equity in the project. In addition, although we have no continuing involvement in the project, we retained the prospect of receiving an additional $1.0 million in additional proceeds upon final closing of Phase II of the project.

Killingholme — During third quarter 2002, we recorded an impairment charge of $477.9 million. In January 2003, we completed the sale of our interest in the Killingholme project to our lenders for a nominal value and forgiveness of outstanding debt with a carrying value of approximately $360.1 million at December 31, 2002. The sale of our interest in the Killingholme project and the release of debt obligations resulted in a gain on sale in the first quarter of 2003 of approximately $191.2 million. The gain results from the write-down of the project's assets in the third quarter of 2002 below the carrying value of the related debt.

NLGI — During 2002, we recorded an impairment charge of $12.4 million related to subsidiaries of NLGI, an indirect wholly owned subsidiary of NRG Energy. The charge was related largely to asset impairments based on a revised project outlook. During the quarter ended March 31, 2003, we recorded impairment charges of $23.6 million related to subsidiaries of NLGI and a charge of $14.5

million to write off our 50% investment in Minnesota Methane LLC. Through April 30, 2003, NRG Energy and NLGI failed to make certain payments causing a default under NLGI's term loan agreements. In May 2003, the project lenders to the wholly owned subsidiaries of NLGI and Minnesota Methane foreclosed on our membership interest in the NLGI subsidiaries and our equity interest in Minnesota Methane. Together with a $2.2 million gain recorded upon completion of the foreclosures of the related equity investees (see Note 4), there was no material net gain or loss recognized as a result of these foreclosures.

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

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

	Reorganized NRG	Predecessor Company	Reorganized NRG	Predecessor Company
	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands)			
Calpine Cogeneration	**$ 500**	$ —	**$ 735**	$ —
Loy Yang	**705**	(139,972)	**(1,268)**	(139,972)
NEO Corporation — Minnesota Methane	**—**	2,196	**—**	(12,257)
Kondapalli	**—**	1,812	**—**	519
ECKG	**—**	3,714	**—**	2,869
Other	**—**	(186)	**—**	(186)
Total write downs and gains/(losses) on sales of equity method investments	**$ 1,205**	$ (132,436)	**$ (533)**	$ (149,027)

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

Loy Yang — We recorded an impairment charge of $111.4 million during 2002 and an additional impairment charge of $140.0 million during the second quarter of 2003 based on a third party market evaluation and bids received in response to marketing Loy Yang for possible sale. During the first quarter of 2004, we wrote down our investment in Loy Yang by $2.0 million due to recent estimates of the expected sales proceeds. In April 2004, we completed the sale of our 25.4% interest in Loy Yang to Great Energy Alliance Corporation, which resulted in net cash proceeds of $26.7 million and a gain of $0.7 million. This resulted in an adjusted loss of $1.3 million for the six months ended June 30, 2004.

NEO Corporation — Minnesota Methane — We recorded an impairment charge of $12.3 million during 2002 to write-down our 50% investment in Minnesota Methane. We recorded an additional impairment charge of $14.5 million during the first quarter of 2003. These charges were related to a revised project outlook and management's belief that the decline in fair value was other than temporary. In May 2003, the project lenders to the wholly owned subsidiaries of NEO Landfill Gas, Inc. and Minnesota Methane foreclosed on our membership interest in the NEO Landfill Gas, Inc. subsidiaries and our equity interest in Minnesota Methane. Upon completion of the foreclosure, we recorded a gain of $2.2 million on the related equity investments. This gain resulted from the legal release of certain obligations.

Lanco Kondapalli Power Pvt Ltd, or Kondapalli — In the fourth quarter of 2002, we wrote down our investment in Kondapalli by $12.7 million due to recent estimates of sales value, which indicated an impairment of our book value that was considered to be other than temporary. On January 30, 2003, we signed a sales agreement with the Genting Group of Malaysia to sell our 30% interest in Kondapalli and a 74% interest in Eastern Generation Services (India) Pvt Ltd. Kondapalli is based in Hyderabad, Andhra Pradesh, India, and is the owner of a 368 MW natural gas fired combined cycle gas turbine. In the first quarter of 2003, we wrote down our investment in Kondapalli by $1.3 million based on the final sales agreement. The sale closed on May 30, 2003 resulting in net cash proceeds of approximately $24 million and a gain of approximately $1.8 million, resulting in a net gain of $0.5 million. The gain resulted from incurring lower selling costs than estimated as part of the first quarter impairment.

ECKG — In September 2002, we announced that we had reached agreement to sell our 44.5% interest in the ECKG power station in connection with our Csepel power generating facilities, and our interest in Entrade, an electricity trading business, to Atel, an independent energy group headquartered in Switzerland. The transaction closed in January 2003 and resulted in cash proceeds of $65.3 million and a net gain of $2.9 million.

Note 5 — Reorganization Items and Restructuring and Impairment Charges

Reorganization items and restructuring and impairment charges included in operating expenses in the consolidated statements of operations include the following:

	Reorganized NRG	Predecessor Company	Reorganized NRG	Predecessor Company
	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
		(In thousands)		
Reorganization items	**$ (2,661)**	$ 6,334	**$ 3,589**	$ 6,334
Restructuring charges	**—**	46,691	**—**	68,161
Impairment charges	**1,676**	222,940	**1,676**	223,606
Total	**$ (985)**	$ 275,965	**$ 5,265**	$ 298,101

Reorganization items – We recorded a net credit of $2.7 million related to reorganization items for the three months ended June 30, 2004. These items relate primarily to the settlement of obligations recorded under Fresh Start. We incurred total reorganization items of approximately $3.6 million for the six months ended June 30, 2004. We incurred total reorganization items of approximately $6.3 million for the three and six months ended June 30, 2003, respectively. All reorganization costs have been incurred since we filed for bankruptcy in May 2003. These costs consist of bankruptcy related charges primarily related to professional fees.

Restructuring charges - We incurred total restructuring charges of approximately $46.7 million and $68.2 million for the three and six months ended June 30, 2003, respectively. These costs consist of employee separation costs and advisor fees.

Impairment charges - We reviewed the recoverability of our long-lived assets in accordance with the guidelines of SFAS No. 144. As a result of this review, we recorded $1.7 million in impairment charges for the three and six months ended June 30, 2004 and $222.9 million and $223.6 million for the three and six months ended June 30, 2003, respectively which included the following:

		Reorganized NRG	Predecessor Company	Reorganized NRG	Predecessor Company	
Project Name	Project Status	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30,2003	Fair Value Basis
			(In thousands)			
New Roads Holding LLC	Non-operating asset	**$ 1,676**	$ —	**$ 1,676**	$ —	Projected cash flows
Devon Power LLC	Operating at a loss	**—**	64,198	**—**	64,198	Projected cash flows
Middletown Power LLC	Operating at a loss	**—**	157,323	**—**	157,323	Projected cash flows
Other	Terminated	**—**	1,419	**—**	2,085	
Total impairment charges		**$ 1,676**	$ 222,940	**$ 1,676**	$ 223,606	

Note 6 — Asset Retirement Obligation

Effective January 1, 2003, we adopted SFAS No. 143, *"Accounting for Asset Retirement Obligations"*. SFAS No. 143 requires an entity to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Over time, the liability is accreted to its present value, and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes or written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

We identified certain retirement obligations within our power generation segments related to our North America projects in the South Central region, the Northeast region, Australia, and our non-generation operations. These asset retirement obligations are related primarily to the future dismantlement of equipment on leased property and environmental obligations related to ash disposal site closures. We also identified other asset retirement obligations that could not be calculated because the assets associated with the retirement obligations were determined to have an indeterminate life.

The following represents the balances of the asset retirement obligation as of December 31, 2003 and the additions and accretion of the asset retirement obligation for the six months ended June 30, 2004, which is included in other long-term obligations in the consolidated balance sheet.

Description	Beginning Balance December 31, 2003	Accretion for the Six Months Ended June 30, 2004	Ending Balance June 30, 2004
		(In thousands)	
South Central Region	$ 2,638	$ 91	$ 2,729
Northeast Region	11,750	400	12,150
Australia	9,438	526	9,964
Non-Generation	1,334	45	1,379
Alternative Energy	834	29	863
Total	$ 25,994	$ 1,091	$ 27,085

Note 7 — Inventory

Inventory, which is stated at the lower of weighted average cost or market, consisted of:

	June 30, 2004	December 31, 2003
	(In thousands)	
Fuel oil	$ 84,861	$ 75,272
Coal	58,179	59,555
Natural gas	1,200	856
Other fuels	88	75
Spare parts	54,532	54,522
Emission credits	4,478	4,478
Other	334	168
Total inventory	$203,672	$ 194,926

Note 8 — Property, Plant and Equipment

The major classes of property, plant and equipment were as follows:

	June 30, 2004	December 31, 2003
	(In thousands)	
Facilities and equipment	$3,784,274	$3,732,391
Land and improvements	133,684	134,888
Office furnishings and equipment	17,957	18,186
Construction in progress	104,794	139,171
Total property, plant and equipment	4,040,709	4,024,636
Accumulated depreciation	(119,487)	(11,800)
Net property, plant and equipment	$3,921,222	$4,012,836

Note 9 — Summarized Financial Information of Affiliates

We have a 50% interest in one company, West Coast Power, which was considered significant, as defined by applicable SEC regulations, which is accounted for as an equity method investment.

West Coast Power LLC Summarized Financial Information

For the three and six months ended June 30, 2004, we recorded equity earnings of $21.9 million and $27.9 million, respectively, for West Coast Power after adjustments for the reversal of $5.6 million and $7.6 million, respectively, of project level depreciation expense, offset by a decrease in earnings related to $30.6 million and $61.6 million, respectively, of amortization of the intangible asset for the California Department of Water Resources, or CDWR contract. As a result of pushing down the impact of Fresh Start to the project's balance sheet, we established a contract-based intangible asset with a one-year remaining life, consisting of the value of West Coast Power's CDWR energy sales contract. In accordance with SOP 90-7, the carrying value of this intangible asset was reduced by $6.9 million as a result of allocating the reduction of our tax valuation allowance to our intangible assets (see Notes 10 and 16). The following table summarizes financial information for West Coast Power, including interests owned by us and other parties for the periods shown below:

Results of Operations

	Three Months Ended		Six Months Ended	
(In millions)	June 30, 2004	June 30, 2003	June 30, 2004	June 30, 2003
Operating revenues	$ 314	$ 267	$ 598	$ 526
Operating income	$ 94	$ 77	$ 164	$ 137
Net income (pre-tax)	$ 94	$ 72	$ 164	$ 131

Financial Position

(In millions)	June 30, 2004	December 31, 2003
Current assets	$ 332	$ 257
Other assets	437	454
Total assets	$ 769	$ 711
Current liabilities	$ 69	$ 55
Other liabilities	8	8
Equity	692	648
Total liabilities and equity	$ 769	$ 711

For several years, the Federal Energy Regulatory Commission, or FERC, has been engaged in investigations regarding potential manipulation of electrical and natural gas prices, and earlier this year, Dynegy, we and the West Coast Power entities commenced extensive settlement negotiations with FERC Staff; the People of the State of California *ex rel.* Bill Lockyer, Attorney General; the California Public Utility Commission, or CPUC staff; the California Department of Water Resources acting through its Electric Power Fund, the California Electricity Oversight Board; PG&E; Southern California Edison Company; and San Diego Gas and Electric Company. The parties have now reached a definitive, comprehensive settlement, which has been filed with FERC and awaits FERC approval.

As part of the settlement agreement, West Coast Power will place into escrow for distribution to various California energy consumers a total of $22.5 million, which includes the $3 million settlement with FERC announced on January 20, 2004. In addition, West Coast Power will forego: (1) past due receivables from the California Independent System Operator, or ISO, and the California Power Exchange related to the settlement period; and (2) natural gas cost recovery claims against the settling parties related to the settlement period. In exchange, the various California settling parties will forego: (1) all claims relating to refunds or other monetary damages for sales of electricity during the settlement period; (2) claims alleging that West Coast Power received unjust or unreasonable rates for the sale of electricity during the settlement period; and (3) FERC will dismiss numerous investigations respecting market transactions. For a two year period following FERC's acceptance of the Settlement Agreement, West Coast Power will retain an independent engineering company to perform semi-annual audits of the technical and economic basis, justification and rationale for outages that occurred at its California generating plants during the previous six month period, and to have the results of such audits provided to the FERC Office of Market Oversight and Investigation without prior review by West Coast Power.

West Coast Power and NRG Energy are fully reserved for both the past due receivables and the cash settlement as of June 30, 2004. West Coast Power is also subject to other legal matters and litigation. Other litigation and investigations respecting West Coast Power are set forth in detail in Note 17.

Note 10 — Intangible Assets

Reorganized NRG

Upon the adoption of Fresh Start, we established certain intangible assets for power sales agreements and plant emission allowances. These intangible assets will be amortized over their respective lives based on a straight-line or units of production basis to resemble our realization of such assets.

Power sale agreements will be amortized as a reduction to revenue over the terms and conditions of each contract. The weighted average remaining amortization period is two years for the power sale agreements. Emission allowances will be amortized as additional fuel expense based upon the actual level of emissions from the respective plants through 2023. Aggregate amortization recognized for the three and six months ended June 30, 2004 was approximately $12.4 million and $29.2 million, respectively. The annual aggregate amortization for each of the five succeeding years is expected to approximate $20.9 million in year one, $33.0 million in year two, $26.8 million in each of years three and four, and $20.3 million in year five for both the power sale agreements and emission allowances. The expected annual amortization of these amounts is expected to change as we relieve our tax valuation allowance, as explained below.

For the six months ended June 30, 2004, we reduced our tax valuation allowance by $44.0 million (see Note 16) and recorded a corresponding reduction of $37.1 million related to our intangible assets at our wholly owned subsidiaries. The remaining $6.9 million was recorded as a reduction to our intangible asset related to our equity investments (see Note 9). In accordance with SOP 90-7, any future benefits from reducing the valuation allowance should first reduce intangible assets until exhausted, and thereafter be recorded as a direct addition to paid-in-capital. Intangible assets were also reduced by $10.0 million in connection with the recognition of certain tax credits to be claimed on our New York state franchise tax return.

Intangible assets consisted of the following:

(In thousands)	Power Sale Agreements	Emission Allowances	Total
Original balance as of December 6, 2003	$ 64,055	$373,518	$437,573
Amortization	(5,212)	—	(5,212)
Balance as of December 31, 2003	58,843	373,518	432,361
Tax valuation adjustment	(3,720)	(33,377)	(37,097)
Other adjustments	—	(10,004)	(10,004)
Amortization	(19,274)	(9,918)	(29,192)
Balance as of June 30, 2004	$ 35,849	$320,219	$356,068

Predecessor Company

We had intangible assets of $27 million at June 30, 2003, which were not amortized and consisted of goodwill. We also had intangible assets of $45.0 million at June 30, 2003, which were amortized and consisted of service contracts. Aggregate amortization expense recognized for the three and six months ended June 30, 2003 was approximately $1.0 million and $2.1 million, respectively.

Note 11 — Derivative Instruments and Hedging Activities

SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*", as amended, requires us to record all derivatives on the balance sheet as assets or liabilities at fair value. For derivatives designated as cash flow hedges, the effective portion of the changes in fair value of the derivatives are recorded in Accumulated Other Comprehensive Income, or OCI, and subsequently recognized in earnings when the hedged items impact 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. Changes in the fair value of non-hedge derivatives will be immediately recognized in earnings. Additionally, many of our commodity sales and purchase agreements that otherwise would be required to follow derivative accounting qualify as normal purchases and sales under SFAS No. 133, and are therefore exempt from fair value accounting treatment.

SFAS No. 133 applies to our long-term power sales contracts, long-term gas purchase contracts and other energy related commodities' financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect investments in fuel inventories. SFAS No. 133 also applies to various interest rate financial instruments used to mitigate the risks associated with movements in interest rates, foreign exchange contracts used to reduce the effect of fluctuating foreign currencies on foreign denominated investments and other transactions.

Accumulated Other Comprehensive Income (OCI)

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

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Accumulated OCI balance at March 31, 2004	$ (15,271)	$ (7,817)	$ —	$(23,088)
Unwound from OCI during period:				
— Due to unwinding of previously deferred amounts	9,408	3,272	—	12,680
Mark-to-market of hedge contracts	(3,079)	27,138	—	24,059
Accumulated OCI balance at June 30, 2004	$ (8,942)	$22,593	$ —	$ 13,651
Gains expected to unwind from OCI during next 12 months	$ 13,138	$24,750	$ —	$ 37,888

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

(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Accumulated OCI balance at December 31, 2003	$ (1,953)	$ 1,600	$ (170)	$ (523)
Unwound from OCI during period:				
— Due to unwinding of previously deferred amounts	8,784	7,058	170	16,012
Mark-to-market of hedge contracts	(15,773)	13,935	—	(1,838)
Accumulated OCI balance at June 30, 2004	$ (8,942)	$22,593	$ —	$13,651
Gains expected to unwind from OCI during next 12 months	$ 13,138	$24,750	$ —	$37,888

Losses of $12.7 million and $16.0 million were reclassified from OCI to current period earnings during the three and six months ended June 30, 2004 due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items are recorded. Also during the three and six months ended June 30, 2004 we recorded gains in OCI of approximately $24.1 million and losses of $1.8 million, respectively, related to changes in the fair values of derivatives accounted for as hedges. The net balance in OCI relating to SFAS No. 133 as of June 30, 2004 was an unrecognized gain of approximately $13.7 million. We expect $37.9 million of deferred net gains on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

Statement of Operations

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

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

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

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

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the three months ended June 30, 2003:

	Predecessor NRG			
(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Revenue from majority-owned subsidiaries	$ 35,722	$ —	$ —	$ 35,722
Equity in earnings of unconsolidated subsidiaries	2,187	(29)	—	2,158
Cost of operations	2,623	—	—	2,623
Interest expense	—	(33,369)	—	(33,369)
Total statement of operations impact before tax	$ 40,532	$ (33,398)	$ —	$ 7,134

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the six months ended June 30, 2003:

	Predecessor NRG			
(Gains/(Losses) In thousands)	Energy Commodities	Interest Rate	Foreign Currency	Total
Revenue from majority-owned subsidiaries	$ 33,293	$ —	$ —	$ 33,293
Equity in earnings of unconsolidated subsidiaries	3,731	(288)	—	3,443
Cost of operations	(9,155)	—	—	(9,155)
Other income	—	—	92	92
Interest expense	—	(45,608)	—	(45,608)
Total statement of operations impact before tax	$ 27,869	$ (45,896)	$ 92	$(17,935)

Energy Related Commodities

We are exposed to commodity price variability in electricity, emission allowances and natural gas, oil and coal used to meet fuel requirements. In order to manage these commodity price risks, we entered into financial instruments, which may take the form of fixed price, floating price or indexed sales or purchases, and options, such as puts, calls, basis transactions and swaps. Certain of these transactions have been designated as cash flow hedges. We have accounted for these derivatives by recording the effective portion of the cumulative gain or loss on the derivative instrument as a component of OCI in stockholders' equity. We recognize deferred gains and losses into earnings in the same period or periods during which the hedged transaction affects earnings. Such reclassifications are included on the same line of the statement of operations in which the hedged item is recorded.

No ineffectiveness was recognized on commodity cash flow hedges during the three and six months ended June 30, 2004 and 2003.

During the three and six months ended June 30, 2004, our pre-tax earnings were increased by an unrealized gain of $15.7 million and $15.0 million, respectively, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

During the three and six months ended June 30, 2003, our pre-tax earnings were increased by an unrealized gain of $40.5 million and $27.8 million, respectively, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

During the three and six months ended June 30, 2004, we reclassified losses of $9.4 million and $8.8 million, respectively, from OCI to current period earnings and expect to reclassify approximately $13.1 million of deferred gains to earnings during the next twelve months on energy related derivative instruments accounted for as hedges.

At June 30, 2004, we had hedge and non-hedge energy related commodities financial instruments extending through December 2005.

Interest Rates

To manage interest rate risk, we have entered into interest-rate swap agreements that fix the interest payments or the fair value of selected debt issuances. The qualifying swap agreements are accounted for as cash flow or fair value hedges. The effective portion of the cash flow hedges' cumulative gains/losses are reported as a component of OCI in stockholders' equity. These gains/losses are recognized in earnings as the hedged interest expense is incurred. The reclassification from OCI is included on the same line of the statement of operations in which the hedged item appears. The entire amount of the change in fair value hedges is recorded in the statement of operations along with the change in value of the hedged item.

No ineffectiveness was recognized on interest rate swaps that qualify as hedges during the three and six months ended June 30, 2004.

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

During the three and six months ended June 30, 2003, pre-tax earnings were decreased by an unrealized loss of $33.4 million and $45.8 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.

During the three and six months ended June 30, 2004, we reclassified losses of $3.3 million and $7.1 million, respectively, from OCI to current period earnings and expect to reclassify approximately $24.8 million of deferred gains to earnings during the next twelve months associated with interest rate swaps accounted for as hedges.

At June 30, 2004, we had interest rate derivatives instruments extending through June 2019.

Foreign Currency Exchange Rates

To preserve the U.S. dollar value of projected foreign currency cash flows, we may hedge, or protect those cash flows if appropriate foreign hedging instruments are available.

No ineffectiveness was recognized on foreign currency cash flow hedges during the three and six months ended June 30, 2004 and 2003.

During the three and six months ended June 30, 2004, our pre-tax earnings were not affected by any gain or loss associated with foreign currency hedging instruments not accounted for as hedges in accordance with SFAS No. 133.

During the three and six months ended June 30, 2003, our pre-tax earnings were increased by unrealized gains of $0 and $92,000 associated with foreign currency hedging instruments not accounted for as hedges in accordance with SFAS No. 133.

During the three months ended June 30, 2004, no amounts were reclassified from OCI to current period earnings. During the six months ended June 30, 2004, we reclassified losses of $0.2 million from OCI to current period earnings and we do not expect to reclassify any deferred gains/losses to earnings during the next twelve months on foreign currency swaps accounted for as hedges.

Note 12 — Short Term Debt and Long Term Debt

As part of and concurrent with our emergence from bankruptcy on December 5, 2003, certain senior unsecured credit facilities were terminated and defaults related to those facilities were eliminated.

As of June 30, 2004, we have made timely scheduled payments on interest and/or principal on all of our recourse debt and were not in default under any of our related recourse debt instruments. Additionally, we are not in default of any obligations to post collateral. However, a significant amount of our subsidiaries' debt and other obligations contain terms that require they be supported with letters of credit or cash collateral.

As discussed below, our NRG McClain project debt was in default as of June 30, 2004, however, on July 9, 2004, NRG McClain executed a sale of its interest in the McClain Generating Station and subsequently used the proceeds to repay outstanding project debt under the secured term loan and working capital facility.

NRG Energy Corporate Debt

On December 5, 2003, we entered into a $10.0 million promissory note with Xcel Energy. The note accrues interest at a rate of 3% per year, payable quarterly in arrears. All principal is due at maturity on June 5, 2006.

On December 23, 2003, we and PMI entered into a Senior Secured Credit Facility for up to $1.45 billion, which is comprised of both long-term and short-term debt. Long-term debt included a $950.0 million, six and a half-year senior secured term loan and a $250.0 million letter of credit facility, funded with proceeds from the senior secured lenders. Principal and interest on the term loan is payable quarterly on March 31, June 30, September 30 and December 31 of each year. As of June 30, 2004, the interest rate on the term loan was 5.56%, based on the London Interbank Offering Rate, or LIBOR, plus a credit spread. The LIBOR portion is subject to a floor of 1.5%.

As of June 30, 2004, the $250.0 million letter of credit facility was fully funded and reflected as a funded letter of credit on the June 30, 2004 balance sheet. As of June 30, 2004, $132.3 million in letters of credit had been issued under this facility, leaving $117.7 million available for future issuances. Expenses associated with the funded letter of credit include commitment fees on the undrawn portion of the letter of credit facility, participation fees for the credit-linked deposit and other fees.

The short-term debt component of the Senior Secured Credit Facility is a four-year, $250.0 million revolving line of credit, or the Corporate Revolver. Portions of the Corporate Revolver are available as a swing-line facility and as a revolving letter of credit sub-facility. As of June 30, 2004, the Corporate Revolver was undrawn. We pay a commitment fee of 1% on any undrawn portion of the Corporate Revolver, and interest on any borrowed amounts.

On December 23, 2003, we issued $1.25 billion in 8% Second Priority Notes, due and payable on December 15, 2013. The 8% Second Priority Notes are general obligations of ours. They are secured on a second-priority basis by security interests in all of our assets, subject to the liens securing our obligations under the Senior Secured Credit Facility and any other priority lien obligations, which will be secured on a first-priority basis by the same assets that secure the 8% Second Priority Notes. The 8% Second Priority Notes will be senior in right of payment to any future subordinated indebtedness. Interest on the 8% Second Priority Notes accrues at the rate of 8.0% per annum and is payable semi-annually in arrears on June 15 and December 15, commencing June 15, 2004.

On January 28, 2004, we issued, at a premium, an additional $475.0 million in 8% Second Priority Notes under the same terms and indenture as the December 23, 2003 offering. Proceeds of the additional offering were used to prepay $503.5 million of the term loan under the Senior Secured Credit Facility, reducing the outstanding principal of the term loan from $950.0 million to $446.5 million. In January 2004 we wrote-off $15.0 million of deferred financing costs (included in interest expense) related to the term loans which were repaid. In addition, we deferred an additional $7.2 million of financing costs related to the newly issued notes.

On February 25, 2004, we amended our Senior Secured Credit Facility to remove an interest rate hedge mandate. The amendment provides us with additional flexibility in how we choose to mitigate interest-rate risk.

On March 24, 2004, we executed an interest rate swap agreement to mitigate our floating-rate interest exposure associated with our Senior Secured Credit Facility. The swap agreement became effective March 26, 2004 and terminates March 31, 2006. Under the agreement, we agree to pay quarterly a fixed interest rate on a notional amount of $400.0 million, commencing on March 31, 2004, and receive quarterly a floating-rate interest rate payment on the same notional amount. The floating rate is based upon three-month LIBOR, subject to a floor.

On March 24, 2004, we executed a second interest rate swap agreement to mitigate our fixed-rate interest exposure associated with our 8% Second Priority Notes. This swap agreement became effective March 26, 2004 and terminates December 15, 2013. The swap agreement has provisions for early termination that are linked to any prepayment of the 8% Second Priority Notes. Under the agreement, we agree to pay semi-annually in arrears, commencing June 15, 2004, a floating interest rate on a notional amount of

$400.0 million, and receive semi-annually in arrears a fixed interest rate payment on the same notional amount. The floating interest rate is based upon six-month LIBOR plus a spread. 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 June 30, 2004, we had posted $17.8 million in collateral. As of August 2, 2004, we have posted $11.1 million in collateral in support of the swaps.

On April 29, 2004, we amended our Senior Secured Credit Facility to give us the flexibility to enter into joint ventures from time to time with affiliates of our 21.5% stockholder, MatlinPatterson Global Opportunities Partners, L.P. Three representatives of MatlinPatterson are members of our board of directors. We paid the lenders and agent under our senior secured credit agreement a fee equal to 12.5 basis points, or approximately $1.2 million, for the amendment.

Certain Events Related to Project Level Debt

NRG McClain LLC Project Debt

On November 28, 2001, NRG McClain entered into a credit agreement with Westdeutsche Landesbank Girozentrale, or West LB AG's, New York Branch and various other lending institutions for a $181.0 million secured term loan and an $8.0 million working capital facility. As of June 30, 2004 and December 31, 2003, the outstanding amount under this facility was $156.5 million. As of June 30, 2004, the interest rate on such outstanding borrowings was 4.625%.

On September 17, 2002, NRG McClain received notice from the agent bank that the project loan was in default as a result of our downgrades and of defaults on material obligations under the Energy Management Services Agreement. On August 19, 2003, NRG McClain signed an asset purchase agreement with Oklahoma Gas & Electric Company, or OG&E, for substantially all of the assets of McClain Generating Station and contemporaneously filed for bankruptcy pursuant to the asset purchase agreement. On July 9, 2004, NRG McClain completed the sale of its 77% interest in the McClain Generating Station to OG&E. The Oklahoma Municipal Power Authority will continue to own the remaining 23% interest in the facility. A portion of the proceeds of $160.2 million, from the sale, was used to repay outstanding project debt under the secured term loan and working capital facility. As of June 30, 2004, NRG McClain was recorded as a discontinued operation on the accompanying financial statements. NRG McClain continues to be in bankruptcy and in default, with the expectation that it will file a liquidating plan of reorganization, settle all its outstanding obligations and be subsequently dissolved.

Note 13 — Corporate Relocation Charges

On March 16, 2004, we announced plans to implement a new regional business strategy and structure. The new structure calls for a reorganized leadership team and a corporate headquarters relocation to West Windsor, New Jersey. The corporate relocation is intended to increase our effectiveness in serving our plants and employees as well as our external stakeholders such as regulators, customers and investors. The corporate headquarters staff will be streamlined as part of the relocation, as functions are shifted to the regions. The transition of our corporate headquarters has commenced and is expected to run through March 2005.

We expect to incur $26.5 million of expenses in connection with corporate relocation charges. Relocating, recruiting and other employee-related transition costs are expected to be approximately $12.8 million. These costs and cash payments are expected to be incurred through first quarter of 2005. Severance and termination benefits of $8.6 million are expected to be incurred through first quarter of 2005 with cash payments being made through fourth quarter of 2005. Building lease termination costs are expected to be $5.1 million. These costs are expected to be incurred through first quarter of 2005 with cash payments being made through fourth quarter of 2006. A summary of the significant components of the restructuring liability is as follows:

(In thousands)	Balance at December 31, 2003	Restructuring Related Charges	Cash Payments	Balance at June 30, 2004
Employee related transition costs	$ —	$ 1,670	$(1,670)	$ —
Severance and termination benefits	—	4,024	(502)	3,522
Lease termination costs	—	1,067	(18)	1,049
Total	$ —	$ 6,761	$(2,190)	$ 4,571

As of June 30, 2004, the restructuring liability was $4.6 million and is included in other current liabilities on the consolidated balance sheet. Charges related to the employee related transition costs, severance and termination benefits and lease termination costs are recorded at our corporate level within our Other segment, in the corporate relocation charges line on the consolidated statement of operations.

Note 14 — Earnings Per Share

Basic earnings per common share were computed by dividing net income by the weighted average number of common stock shares outstanding. Shares issued during the year are weighted for the portion of the year that they were outstanding. Shares of common stock granted to our officers and employees are included in the computation only after the shares become fully vested. 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 reconciliation of basic earnings per common share to diluted earnings per common share is shown in the following table:

	Reorganized NRG	
	Three Months Ended June 30, 2004	Six Months Ended June 30, 2004
	(In thousands, except per share data)	
Basic earnings per share		
Numerator:		
Income from continuing operations	$ 68,869	$ 99,969
Income on discontinued operations, net of income taxes	14,155	13,290
Net income	$ 83,024	$ 113,259
Denominator:		
Weighted average number of common shares outstanding	100,080	100,051
Income from continuing operations per weighted average common share	$ 0.69	$ 1.00
Income from discontinued operations, net of income taxes per weighted average common share	0.14	0.13
Net income per weighted average common share — basic	$ 0.83	$ 1.13
Diluted earnings per share		
Numerator		
Income from continuing operations	$ 68,869	$ 99,969
Income on discontinued operations, net of income taxes	14,155	13,290
Net income	$ 83,024	$ 113,259
Denominator:		
Weighted average number of common shares outstanding	100,080	100,051
Incremental shares attributable to the assumed exercise of outstanding stock options (treasury stock method)	—	—
Incremental shares attributable to the issuance of nonvested restricted stock units (treasury stock method)	398	163
Total dilutive shares	100,478	100,214
Income from continuing operations per weighted average common share – diluted	$ 0.69	$ 1.00
Income from discontinued operations, net of income taxes per weighted average common share - diluted	0.14	0.13
Net income per weighted average common share - diluted	$ 0.83	$ 1.13

For the three and six months ended June 30, 2004, options totaling 770,751 and 786,751, respectively, have been excluded from the dilutive calculation as their exercise price exceeded the average market price of the common shares and therefore the effect would be anti-dilutive.

Stock options: During the period January 1, 2004 through June 30, 2004, we issued stock option grants for 307,000 shares of common stock under the Long-Term Incentive Plan at fair values between $19.90 and $22.24. These options have a three-year graded vesting schedule. Compensation expense recorded under the stock option grants for the three and six months ended June 30, 2004 was approximately $1.8 million and $3.1 million, respectively.

Restricted stock units: During the period January 1, 2004 through June 30, 2004, we issued 655,100 Restricted Stock Units, or RSUs, under the Long-Term Incentive Plan at fair values between $19.90 and $23.00 per unit. These units cliff vest in three years. Compensation expense recorded under the RSUs for the three and six months ended June 30, 2004 was approximately $1.4 million and $2.1 million, respectively. For purposes of computing earnings per share, nonvested RSUs 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.

Deferred stock units: During the period January 1, 2004 through June 30, 2004, we issued 100,961 Deferred Stock Units, or DSUs, under the Long-Term Incentive Plan at fair values between $19.95 and $21.05 per unit. A DSU will entitle the grantee to receive either one share of common stock or RSU at the end of the deferral period of not less than one year. Compensation expense recorded under the DSUs for the three and six months ended June 30, 2004 was approximately $0.8 million and $2.1 million, respectively. For the purposes of computing basic earnings per share, the DSUs are considered outstanding upon grant on a weighted average basis.

Note 15 — Segment Reporting

In connection with our emergence from bankruptcy and the new management team, we determined that it was necessary to adjust our segment reporting disclosures to more closely align our disclosures with the realignment of our management team. Accordingly, we have expanded our domestic geographical disclosures and collapsed our international geographical disclosures related to our wholesale power generation segment. In addition, our other segments have been further refined. As a result of these changes, we have recast our prior period disclosures in a consistent manner.

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. Segment information for the three and six months ended June 30, 2004 and 2003 is as follows:

	Reorganized NRG Three Months Ended June 30, 2004 Wholesale Power Generation (In thousands)				
	Northeast	South Central	West Coast	Other North America	Australia
Operating Revenues	$ 275,029	$ 102,497	$ 929	$ 29,587	$ 36,793
Corporate relocation charges	—	1	—	—	—
Reorganization items	28	(70)	—	1	—
Restructuring and impairment charges	—	1,676	—	—	—
Write downs and gains/(losses) on sales of equity method investments	—	—	—	500	705
Income/(Loss) from Continuing Operations Before Income Taxes	56,230	16,494	23,237	(868)	(8,278)
Income tax expense (benefit)	—	—	185	409	(3,370)
Income/(Loss) From Continuing Operations	56,230	16,494	23,052	(1,277)	(4,908)
Income/(Loss) on Discontinued Operations, net of Income Taxes	—	—	—	1,915	—
Net Income/(Loss)	56,230	16,494	23,052	638	(4,908)
Balance Sheet Total Assets	$2,000,169	$1,138,749	$319,937	$1,965,970	$869,228

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	Reorganized NRG Three Months Ended June 30, 2004 (In thousands)				
	Wholesale Power Generation	All Other			
	Other International	Alternative Energy	Non-Generation	Other	Total
Operating Revenues	**$ 39,374**	**$ 18,833**	**$ 71,778**	**$ (1,146)**	**$ 573,674**
Corporate relocation charges	**—**	**—**	**—**	**5,644**	**5,645**
Reorganization items	**(1)**	**—**	**(528)**	**(2,091)**	**(2,661)**
Restructuring and impairment charges	**—**	**—**	**—**	**—**	**1,676**
Write downs and gains/(losses) on sales of equity method investments	**—**	**—**	**—**	**—**	**1,205**
Income/(Loss) from Continuing Operations Before Income Taxes	**26,263**	**3,658**	**44,378**	**(55,923)**	**105,191**
Income tax expense (benefit)	**5,306**	**4**	**435**	**33,353**	**36,322**
Income/(Loss) From Continuing Operations	**20,957**	**3,654**	**43,943**	**(89,276)**	**68,869**
Income/(Loss) on Discontinued Operations, net of Income Taxes	**12,237**	**—**	**—**	**3**	**14,155**
Net Income/(Loss)	**33,194**	**3,654**	**43,943**	**(89,273)**	**83,024**
Balance Sheet Total Assets	**$ 807,787**	**$ 64,648**	**$552,773**	**$834,014**	**$8,553,275**

	Predecessor Company Three Months Ended June 30, 2003 Wholesale Power Generation (In thousands)				
	Northeast	South Central	West Coast	Other North America	Australia
Operating Revenues	$ 201,299	$ 92,820	$ 4,953	$ 19,667	$ 34,408
Reorganization items	566	886	—	—	—
Restructuring and impairment charges	223,724	1,249	—	41,598	6
Write downs and gains/(losses) on sales of equity method investments	—	—	—	(186)	(139,972)
Income/(Loss) from Continuing Operations Before Income Taxes	(299,805)	(1,090)	38,729	(63,680)	(146,612)
Income tax expense (benefit)	—	—	264	732	(1,780)
Income/(Loss) From Continuing Operations	(299,805)	(1,090)	38,465	(64,412)	(144,832)
Income/(Loss) on Discontinued Operations, net of Income Taxes	—	—	—	(100,480)	—
Net Income/(Loss)	(299,805)	(1,090)	38,465	(164,892)	(144,832)
Balance Sheet Total Assets	$2,461,126	$1,374,882	$466,675	$2,610,196	$ 545,208

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	Predecessor Company Three Months Ended June 30, 2003 (In thousands)				
	Wholesale Power Generation	All Other			
	Other International	Alternative Energy	Non-Generation	Other	Total
Operating Revenues	$ 39,532	$ 18,418	$ 31,992	$ (1,490)	$ 441,599
Reorganization items	—	—	—	4,882	6,334
Restructuring and impairment charges	221	—	10	2,823	269,631
Write downs and gains/(losses) on sales of equity method investments	5,526	2,196	—	—	(132,436)
Income/(Loss) from Continuing Operations Before Income Taxes	15,313	4,203	5,294	(57,097)	(504,745)
Income tax expense (benefit)	2,822	(52)	148	2,171	4,305
Income/(Loss) From Continuing Operations	12,491	4,255	5,146	(59,268)	(509,050)
Income/(Loss) on Discontinued Operations, net of Income Taxes	4,593	3,043	—	(6,507)	(99,351)
Net Income/(Loss)	17,084	7,298	5,146	(65,775)	(608,401)
Balance Sheet Total Assets	$1,459,490	$ 89,555	$345,752	$657,985	$10,010,869

	Reorganized NRG Six Months Ended June 30, 2004 Wholesale Power Generation (In thousands)				
	Northeast	South Central	West Coast	Other North America	Australia
Operating Revenues	**$605,569**	**$197,762**	**$ (2,393)**	**$ 50,422**	**$99,022**
Corporate relocation charges	—	**1**	—	—	—
Reorganization items	**349**	**653**	—	**151**	—
Restructuring and impairment charges	—	**1,676**	—	—	—
Write downs and gains/(losses) on sales of equity method investments	—	—	—	**735**	**(1,268)**
Income/(Loss) from Continuing Operations Before Income Taxes	**143,658**	**27,871**	**24,600**	**(10,770)**	**8,122**
Income tax expense (benefit)	—	—	**337**	**744**	**(106)**
Income/(Loss) From Continuing Operations	**143,658**	**27,871**	**24,263**	**(11,514)**	**8,228**
Income/(Loss) on Discontinued Operations, net of Income Taxes	—	—	—	**933**	—
Net Income/(Loss)	**143,658**	**27,871**	**24,263**	**(10,581)**	**8,228**

	Reorganized NRG Six Months Ended June 30, 2004 (In thousands)				
	Wholesale Power Generation	All Other			
	Other International	Alternative Energy	Non-Generation	Other	Total
Operating Revenues	**$ 79,440**	**$ 32,485**	**$113,447**	**$ (1,762)**	**$1,173,992**
Corporate relocation charges	—	—	—	**6,760**	**6,761**
Reorganization items	—	—	**160**	**2,276**	**3,589**
Restructuring and impairment charges	—	—	—	—	**1,676**
Write downs and gains/(losses) on sales of equity method investments	—	—	—	—	**(533)**
Income/(Loss) from Continuing Operations Before Income Taxes	**40,617**	**4,203**	**53,151**	**(140,881)**	**150,571**
Income tax expense (benefit)	**9,450**	**8**	**600**	**39,569**	**50,602**
Income/(Loss) From Continuing Operations	**31,167**	**4,195**	**52,551**	**(180,450)**	**99,969**
Income/(Loss) on Discontinued Operations, net of Income Taxes	**12,357**	—	—	—	**13,290**
Net Income/(Loss)	**43,524**	**4,195**	**52,551**	**(180,450)**	**113,259**

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	Predecessor Company Six Months Ended June 30, 2003 Wholesale Power Generation (In thousands)				
	Northeast	South Central	West Coast	Other North America	Australia
Operating Revenues	$ 440,864	$196,927	$ 6,373	$ 36,740	$ 82,424
Reorganization items	566	886	—	—	—
Restructuring and impairment charges	224,484	1,918	—	41,970	6
Write downs and gains/(losses) on sales of equity method investments	—	—	—	(186)	(139,972)
Income/(Loss) from Continuing Operations Before Income Taxes	(320,553)	8,857	62,728	(99,333)	(136,612)
Income tax expense (benefit)	—	—	36,444	1,623	(1,263)
Income/(Loss) From Continuing Operations	(320,553)	8,857	26,284	(100,956)	(135,349)
Income/(Loss) on Discontinued Operations, net of Income Taxes	—	—	—	(108,773)	—
Net Income/(Loss)	(320,553)	8,857	26,284	(209,729)	(135,349)

	Predecessor Company Six Months Ended June 30, 2003 (In thousands)				
	Wholesale Power Generation	All Other			
	Other International	Alternative Energy	Non-Generation	Other	Total
Operating Revenues	$ 73,105	$ 31,792	$ 71,870	$ (3,486)	$ 936,609
Reorganization items	—	—	—	4,882	6,334
Restructuring and impairment charges	(3,352)	—	26	26,715	291,767
Write downs and gains/(losses) on sales of equity method investments	3,388	(12,257)	—	—	(149,027)
Income/(Loss) from Continuing Operations Before Income Taxes	31,497	(10,219)	12,762	(194,380)	(645,253)
Income tax expense (benefit)	5,987	(52)	820	(6,217)	37,342
Income/(Loss) From Continuing Operations	25,510	(10,167)	11,942	(188,163)	(682,595)
Income/(Loss) on Discontinued Operations, net of Income Taxes	208,951	(22,955)	—	(15,661)	61,562
Net Income/(Loss)	234,461	(33,122)	11,942	(203,824)	(621,033)

Note 16 — Income Taxes

The income tax provisions for the six months ended June 30, 2004 and June 30, 2003 have been recorded on the basis that we and our U.S. subsidiaries will file a consolidated federal income tax return for 2004 and separate federal income tax returns for the period January 1 to December 5, 2003.

Income tax expense for the three and six months ended June 30, 2004 was $36.3 million and $50.6 million, respectively, compared to a tax expense of $4.3 million and $37.3 million, respectively, for the same periods in 2003. The tax expense for the six months ended June 30, 2004 includes U.S. tax expense of $41.0 million and foreign tax expense of $9.6 million. The tax expense for the six months ended June 30, 2003 includes U.S. tax expense of $32.3 million and foreign tax expense of $5.0 million.

For U.S. income tax purposes, the tax expense in 2004 is due to a reduction in deferred tax assets without a tax benefit for the corresponding reduction in valuation allowance. Due to the uncertainty of realization of deferred tax assets related to net operating losses and other temporary differences, our U.S. net deferred tax assets at December 5, 2003 were offset by a full valuation allowance of $1.3 billion in accordance with SFAS No. 109, "*Accounting for Income Taxes*". SOP 90-7 requires that reductions in the valuation allowance as of December 5, 2003 (date of emergence) first reduce intangible assets until exhausted and thereafter be reported as a direct addition to paid-in-capital. Consequently, our effective tax rate in post bankruptcy emergence years will not benefit from reductions in the valuation allowance. For 2003, the U.S. tax expense is due to an additional valuation allowance recorded against the deferred tax assets of NRG West Coast LLC as a result of its conversion from a corporation to a disregarded entity for federal income tax purposes. Subsequent to the conversion, NRG West Coast will no longer be taxed as an entity separate from NRG Energy.

The foreign tax expense for the first six months of 2004 and 2003 is due to the earnings in foreign jurisdictions.

The effective income tax rate for the six months ended June 30, 2004 differs from the statutory federal income tax rate of 35% primarily due to lower tax rates in foreign jurisdictions and to the SOP 90-7 requirement that reductions to the valuation allowance as of December 5, 2003 (date of emergence) first reduce intangible assets until exhausted and thereafter be reported as a direct addition to paid-in-capital. The effective income tax rate for the six months ended June 30, 2003 differs from the statutory federal income tax rate of 35% primarily due to limitations on tax benefits.

We assessed the likelihood that a substantial portion of our deferred tax assets relating to the net operating loss carryforwards would not be realized. 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. As a result of such assessment, we determined that it was more likely than not that the deferred tax assets related to our domestic net operating loss carryforwards would not be realized. A full valuation allowance was recorded against the net deferred tax assets including net operating loss carryforwards. We also determined that it is more likely than not that a substantial portion of the net operating loss generated in 2002 and 2003 could be determined to be capital in nature. Given that capital losses are of a different character than ordinary losses the likelihood of capital losses expiring unutilized is greater than that of ordinary net operating losses.

In addition, the conversion of ordinary losses to capital losses, to the extent that amount exceeds our existing net operating loss, results in a corresponding reduction to the tax basis of our fixed assets. The consequence of which is a reduction to expected tax depreciation expense in future years.

Note 17 — Commitments and Contingencies

Legal Issues

California Wholesale Electricity Litigation and Related Investigations

People of the State of California ex. rel. Bill Lockyer, Attorney General, v. Dynegy, Inc. et al., United States District Court, Northern District of California, Case No. C-02-O1854 VRW; United States Court of Appeals for the Ninth Circuit, Case No. 02-16619.

This action was filed in state court on March 11, 2002 against us, Dynegy, Dynegy Power Marketing, Inc., Xcel Energy, West Coast Power and four of West Coast Power's operating subsidiaries. Through our subsidiary, NRG West Coast LLC, we are a 50 percent beneficial owner with Dynegy of West Coast Power, which owns, operates, and markets the output of four California plants. Dynegy and its affiliates and subsidiaries are responsible for gas procurement and marketing and trading activities on behalf of West Coast Power. The complaint alleges that the defendants violated California Business & Professions Code § 17200 by selling ancillary services to the California Independent Service Operator, or ISO, and subsequently selling the same capacity into the spot market. The California Attorney General seeks injunctive relief as well as restitution, disgorgement and civil penalties.

On April 17, 2002, the defendants removed the case to the United States District Court in San Francisco. Thereafter, the case was transferred to Judge Vaughn Walker, who is also presiding over various other "ancillary services" cases brought by the California Attorney General against other participants in the California market, as well as other lawsuits brought by the Attorney General against these other market participants. We have tolling agreements in place with the Attorney General with respect to such other proposed claims against us.

The Attorney General filed motions to remand, which the defendants opposed in July of 2002. In an Order filed in early September 2002, Judge Walker denied the remand motions. The Attorney General appealed that decision to the United States Court of Appeal for the Ninth Circuit. The Attorney General also sought a stay of proceedings in the district court pending the appeal, and this request was also denied. In a lengthy opinion filed March 25, 2003, Judge Walker dismissed the Attorney General's action against Dynegy and us with prejudice, finding it was barred by the filed-rate doctrine and preempted by federal law. The Attorney General filed a Notice of Appeal respecting that decision, and the two appeals were consolidated. On July 6, 2004, the Ninth Circuit rejected the Attorney General's appeals and affirmed both decisions of the district court, including the dismissal of all the Attorney General's substantive claims. On October 29, 2004, the Ninth Circuit denied the Attorney General's petitions for rehearing.

Public Utility District of Snohomish County v. Dynegy Power Marketing, Inc et al., Case No. 02-CV-1993 RHW, United States District Court, Southern District of California (part of MDL 1405).

This action was filed against us, Dynegy, Xcel Energy and several other market participants in the United States District Court in Los Angeles on July 15, 2002. The complaint alleges violations of the California Business & Professions Code § 16720 (the Cartwright Act) and Business & Professions Code § 17200. The basic claims are price fixing and restriction of supply, and other market "gaming" activities.

The action was transferred from Los Angeles to the United States District Court in San Diego and was made a part of the Multi-District Litigation proceeding described below. All defendants filed motions to dismiss and to strike in the fall of 2002. In an Order dated January 6, 2003, Judge Robert Whaley, a federal judge from Spokane sitting in the United States District Court in San Diego, pursuant to the Order of the Multi-District Litigation Panel, granted the motions to dismiss on the grounds of federal preemption and filed-rate doctrine. The plaintiff filed a notice of appeal, and the appeal was argued in June, 2004. Consistent with its July, 2004 decision in People of the State of California ex. rel. Bill Lockyer, described above, the Ninth Circuit on September 10, 2004 rejected plaintiff's appeal, holding that plaintiff's claims are banned by federal preemption and the filed-rate doctrine.

In re: Wholesale Electricity Antitrust Litigation, MDL 1405, United States District Court, Southern District of California, pending before Judge Robert H. Whaley. The cases included in this proceeding are as follows:

Pamela R Gordon, on Behalf of Herself and All Others Similarly Situated v Reliant Energy, Inc. et al., Case No. 758487, Superior Court of the State of California, County of San Diego (filed on November 27, 2000).

Ruth Hendricks, On Behalf of Herself and All Others Similarly Situated and On Behalf of the General Public v. Dynegy Power Marketing, Inc. et al., Case No. 758565, Superior Court of the State of California, County of San Diego (filed November 29, 2000).

The People of the State of California, by and through San Francisco City Attorney Louise H. Renne v. Dynegy Power Marketing, Inc. et al., Case No. 318189, Superior Court of California, San Francisco County (filed January 18, 2001).

Pier 23 Restaurant, A California Partnership, On Behalf of Itself and All Others Similarly Situated v PG&E Energy Trading et al., Case No. 318343, Superior Court of California, San Francisco County (filed January 24, 2001).

Sweetwater Authority, et al. v. Dynegy, Inc. et al., Case No. 760743, Superior Court of California, County of San Diego (filed January 16, 2001).

Cruz M Bustamante, individually, and Barbara Matthews, individually, and on behalf of the general public and as a representative taxpayer suit, v. Dynegy Inc. et al., inclusive. Case No. BC249705, Superior Court of California, Los Angeles County (filed May 2, 2001).

All of West Coast Power's operating subsidiaries are defendants in at least one of these six coordinated cases, which were all filed in late 2000 and 2001 in various state courts throughout California. We are also a defendant in all of them. The cases allege unfair competition, market manipulation and price fixing. All the cases were removed to the appropriate United States District Courts, and were thereafter made the subject of a petition to the Multi-District Litigation Panel (Case No. MDL 1405). The cases were ultimately assigned to Judge Whaley. Judge Whaley entered an order in 2001 remanding the cases to state court, and thereafter the cases were coordinated pursuant to state court coordination proceedings before a single judge in San Diego Superior Court. Thereafter, Reliant Energy and Duke Energy filed cross-complaints naming various Canadian, Mexican and United States government entities. Some of these defendants once again removed the cases to federal court, where they were again assigned to Judge Whaley. The defendants filed motions to dismiss and to strike under the filed-rate and federal preemption theories, and the plaintiffs challenged the district court's jurisdiction and sought to have the cases remanded to state court. In December 2002, Judge Whaley issued an opinion finding that federal jurisdiction was absent in the district court, and remanding the cases to state court. Duke Energy and Reliant Energy then filed a notice of appeal with the Ninth Circuit, and also sought a stay of the remand pending appeal. The stay request was denied by Judge Whaley. On February 20, 2003, however, the Ninth Circuit stayed the remand order and accepted jurisdiction to hear the appeal of Reliant Energy and Duke Energy on the remand order, and that appeal was argued in June, 2004 and is pending. We anticipate that filed-rate/federal preemption pleading challenges will be renewed once the remand appeal is decided.

"Northern California" cases against various market participants, not including us (part of MDL 1405). These include the *Millar, Pastorino, RDJ Farms, Century Theatres, El Super Burrito, Leo's, J&M Karsant,* and *Bronco Don* cases.

We were not named in any of these cases, but in virtually all of them, either West Coast Power or one or more of its operating subsidiaries is named as a defendant. These cases all allege violation of Business & Professions Code § 17200, and are similar to the various allegations made by the Attorney General. Dynegy is named as a defendant in all these actions, and Dynegy's outside counsel is representing both Dynegy and the West Coast Power entities in each of these cases. These cases all were removed to federal court, made part of the Multi-District Litigation, and denied remand to state court. In late August 2003, Judge Whaley granted the defendants' motions to dismiss in these various cases, which are now the subject of the plaintiffs' appeal to the Ninth Circuit Court of Appeals.

Bustamante v. McGraw-Hill Companies, Inc., et al., No. BC 235598, California Superior Court, Los Angeles County.

This putative class action lawsuit was filed on November 20, 2002. The complaint generally alleges that the defendants attempted to manipulate gas indexes by reporting false and fraudulent trades. Named defendants in the suit include numerous industry participants unrelated to us, as well as the operating subsidiaries established by West Coast Power for each of its four plants: El Segundo Power, LLC; Long Beach Generation, LLC; Cabrillo Power I LLC; and Cabrillo Power II LLC. The complaint seeks restitution and disgorgement of "ill-gotten gains," civil fines, compensatory and punitive damages, attorneys' fees and declaratory and injunctive relief. The plaintiff filed an amended complaint in 2003.

Jerry Egger, et al. v. Dynegy, Inc., et al., Case No. 809822, Superior Court of California, San Diego County (filed May 1, 2003).

This class action complaint alleges violations of California's Antitrust Law, and Business and Professions Code, as well as unlawful and unfair business practices. The named defendants include "West Coast Power, Cabrillo II, El Segundo Power, Long Beach Generation." We are not named. This case now has been removed to the United States District Court, and the defendants have moved to have this case included as Multi-District Litigation along with the above referenced cases before Judge Walker. Plaintiffs have filed a motion to remand to state court, which was heard on February 19, 2004. At the hearing, the court decided to stay the case pending a decision from the Ninth Circuit Court of Appeals in the Pastorino appeal, referenced above.

Texas-Ohio Energy, Inc., on behalf of Itself and all others similarly situated v. Dynegy, Inc. Holding Co., West Coast Power, LLC, et al., Case No. CIV.S-03-2346 DFL GGH.

This putative class action was filed on November 10, 2003, in the United States District Court for the Eastern District of California. The complaint alleges violations of the federal Sherman and Clayton Acts and California's Cartwright Act and Business and Professions Code. In addition to naming West Coast Power and "Dynegy, Inc. Holding Co.," the complaint names numerous industry participants, as well as "unnamed co-conspirators." The complaint alleges that defendants conspired to manipulate the spot price and basis differential of natural gas with respect to the California market, allegedly enabling defendants to reap exorbitant and illicit profits by gouging natural gas purchasers. Specifically, the complaint alleges that defendants and their co-conspirators employed a variety of false reporting techniques to manipulate the published natural gas price indices. The complaint seeks unspecified amounts of damages, including a trebling of plaintiff's and the putative class's actual damages. We are unable at this time to predict the outcome of this dispute or the ultimate liability, if any, of West Coast Power.

City of Tacoma, Department of Public Utilities, Light Division, v. American Electric Power Service Corporation, et al., United States District Court, Western District of Washington, Case No. C04-5325 RBL

This action was filed in early June, 2004 in Washington federal district court. The complaint names over 50 defendants, including West Coast Power's four operating subsidiaries and various Dynegy entities. The complaint also names both us and West Coast Power as "Non-Defendant Co-Conspirators." Plaintiff alleges that defendants, acting in concert with some or all of the Non-Defendant Co-Conspirators, violated the federal Sherman Act by unlawfully withholding power generation from, and/or unlawfully inflating the apparent demand for power in, markets in California and elsewhere in the western United States, thereby causing plaintiff to pay power prices substantially above what it would have otherwise paid. Plaintiff alleges defendants' unlawful activities began at least as early as May, 2000, and continued through at least the end of 2001. Plaintiff claims damages in excess of $175 million. We cannot predict the likelihood of an unfavorable outcome at this time.

County of Santa Clara v. Sempra Energy, et al., San Diego County Superior Court

This action was filed in early July, 2004 in California state court. Although we understand that the complaint names West Coast Power and various Dynegy entities among the numerous defendants, West Coast Power has not been served. The complaint apparently alleges violation of California's Cartwright Act and Business and Professions Code and unjust enrichment relating to alleged reporting of false natural gas prices and trading information to inflate retail prices for defendants' benefit. We cannot predict the likelihood of an unfavorable outcome at this time.

City and County of San Francisco; The People of the State of California; Dennis J. Herrera v Sempra Energy, et al., San Diego County Superior Court

This action was filed in early July, 2004 in California state court. The complaint names West Coast Power and various Dynegy entities among the numerous defendants. Like the above *County of Santa Clara* case, the complaint alleges violation of California's Cartwright Act and Business and Professions Code and unjust enrichment, as well as unfair competition, asserting that defendants conspired and acted in concert to manipulate retail gas prices, thereby allowing defendants to sell natural gas at prices far above competitive levels. We cannot predict the likelihood of an unfavorable outcome at this time

County of San Diego v. Sempra Energy, et al., San Diego County Superior Court

This action was filed in late July, 2004 in California state court. The complaint names West Coast Power and various Dynergy entities among the numerous defendants. Like the above *City and County of San Francisco* case, the complaint asserts that defendants conspired to manipulate retail gas prices, thereby allowing defendants to sell natural gas at grossly inflated prices. We cannot predict the likelihood of an unfavorable outcome at this time.

Older v. Sempra Energy, et al., San Diego County Superior Court

This putative class action lawsuit was filed in late September, 2004 in California state court. The complaint names West Coast Power and various Dynegy entities among the numerous defendants. The complaint alleges violation of California Business & Professions Code § 16720 (the Cartwright Act) and Business & Professions Code § 17200, based on defendants' alleged efforts to fix, raise, stabilize, maintain and manipulate retail natural gas prices in California at supra-competitive levels. The complaint seeks a determination of class action status, a trebling of unspecified damages, restitution, disgorgement and costs and attorneys' fees. We cannot predict the likelihood of an unfavorable outcome at this time.

California Investigations

FERC — California Market Manipulation

The Federal Energy Regulatory Commission has had an ongoing "Investigation of Potential Manipulation of Electric and Natural Gas Prices," involving hundreds of parties (including our affiliate, West Coast Power) and substantial discovery. In June 2001, FERC initiated proceedings related to California's demand for $8.9 billion in refunds from power sellers who allegedly inflated wholesale prices during the energy crisis. Hearings were conducted before an administrative law judge, who issued an opinion in late 2002. The administrative law judge stated that after assessing a refund of $1.8 billion for "unjust and unreasonable" power prices between October 2, 2000 and June 20, 2001, power suppliers were owed $1.2 billion because the State was holding funds owed to suppliers.

In August 2002, the United States Circuit Court of Appeals for the Ninth Circuit granted a request by the Electricity Oversight Board, the California Public Utilities Commission and others, to seek out and introduce to FERC additional evidence of market manipulation by wholesale sellers. This decision resulted in FERC ordering an additional 100 days of discovery in the refund proceeding, and also allowing the relevant time period for potential refund liability to extend back an additional nine months, to January 1, 2000.

On December 12, 2002, FERC Administrative Law Judge Birchman issued a Certification of Proposed Findings on California Refund Liability in Docket No. EL00-95-045 et al., which determined the method for calculating the mitigated energy market clearing price during each hour of the refund period. On March 26, 2003, FERC issued an Order on Proposed Findings on Refund Liability, or "Refund Order," in Docket No. EL00-95-045, adopting, in part, and modifying, in part, the Proposed Findings issued by Judge Birchman on December 12, 2002. In the Refund Order, FERC adopted the refund methodology in the Staff Final Report on Price Manipulation in Western Markets issued contemporaneously with the Refund Order in Docket No. PA02-2-000. This refund calculation methodology made certain changes to Judge Birchman's methodology, because of FERC Staff's findings of manipulation in gas index prices. The Refund Order directed generators wanting to recover any fuel costs above the mitigated market clearing price during the refund period to submit cost information justifying such recovery within 40 days of the issuance of the Refund Order, which West Coast Power did.

Dynegy, we and the West Coast Power entities have been engaged in extensive settlement negotiations with FERC Staff; the People of the State of California *ex rel.* Bill Lockyer, Attorney General; the California Public Utility Commission, or CPUC, staff; the California Department of Water Resources acting through its Electric Power Fund, the California Electricity Oversight Board, PG&E; Southern California Edison Company; and San Diego Gas and Electric Company. The parties have now entered into a definitive, comprehensive settlement, which FERC approved on October 25, 2004.

As part of the settlement agreement, West Coast Power will place into escrow for distribution to various California energy consumers a total of $22.5 million, which includes the $3 million settlement with FERC announced on Jan. 20, 2004. In addition, West Coast Power will forego: (1) Past due receivables from the California Independent System Operator, or ISO, and the California Power Exchange related to the settlement period; and (2) natural gas cost recovery claims against the settling parties related to the settlement period. In exchange, the various California settling parties will forego: (1) All claims relating to refunds or other monetary damages for sales of electricity during the settlement period; (2) claims alleging that West Coast Power received unjust or unreasonable rates for the sale of electricity during the settlement period; and (3) FERC will dismiss numerous investigations respecting market transactions. For a two year period following FERC's acceptance of the Settlement Agreement, West Coast Power will retain an independent engineering company to perform semi-annual audits of the technical and economic basis, justification and rationale for outages that occurred at its California generating plants during the previous six month period, and to have the results of such audits provided to the FERC Office of Market Oversight and Investigation without prior review by West Coast Power.

Since the inception of the disputes related to energy sales in California at the end of 2000, West Coast Power has established significant reserves on its balance sheet. As a result, we will not incur any further loss associated with this settlement. We will pay no cash from corporate funds, nor will the settlement have any direct impact on the Company's statement of operations.

Other FERC Proceedings

There are a number of additional, related proceedings in which West Coast Power entities are parties, which are either pending before FERC or on appeal from FERC to various United States Courts of Appeal. These cases involve, among other things, 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 ISO and the State of California and certain of its agencies and departments.

U.S. Attorney — Houston

The U.S. Attorney indicted two fired Dynegy traders in connection with the index reporting scheme, and is reportedly investigating other Dynegy activity and employees.

U.S. Attorney — San Francisco

According to press reports, the U.S. Attorney in San Francisco assembled an “energy crisis” task force. While Dynegy received a grand jury subpoena in November 2002, the scope and targets of this investigation are unknown to us. We did not receive a subpoena.

California State Senate Select Committee

This Committee, chaired by Senator Dunn, subpoenaed records from us during the summer of 2001. We produced about 5,000 pages of documents; Dynegy produced a much larger volume of documents. The Committee has apparently concluded its activities without issuing any reports or findings.

CPUC

The CPUC continues to request data and documents in several settings. First, it is one of the parties in the FERC proceeding mentioned above. Second, inspectors have visited West Coast Power plants, usually unannounced and usually immediately following an unplanned outage. They have demanded documentation concerning the reason for the outage. Third, the CPUC has demanded documents to allow it to prepare “reports,” one of which was issued in the fall of 2002, and another of which was issued January 30, 2003. The FERC’s above-referenced March 26 Refund Order undercut the accuracy and reliability of these CPUC reports. Dynegy has made extensive productions to the CPUC of plant-related materials as well as trading data.

California Attorney General

In addition to the litigation it has undertaken described above, 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.” In this connection, the Attorney General issued subpoenas to Dynegy, served interrogatories on Dynegy and us, and informally requested documents and interviews from Dynegy and Dynegy employees as well as us and our employees. We responded to the interrogatories in the summer of 2002, with the final set of responses being served on September 3, 2002. We also produced a large volume of documentation relating to the West Coast Power plants. In addition, our employees in California sat for informal interviews with representatives of the Attorney General’s office. Dynegy employees also were interviewed.

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.

Although any evaluation of the likelihood of an unfavorable outcome or an estimate of the amount or range of potential loss in the above-referenced private actions and various investigations cannot be made at this time, we note that the *Gordon* complaint, discussed above, alleges that the defendants, collectively, overcharged California ratepayers during 2000 by $4.0 billion.

Electricity Consumers Resource Council v. Federal Energy Regulatory Commission, Docket No. 03-1449

On December 19, 2003 the Electricity Consumers Resource Council, or ECRC, appealed to the United States Court of Appeals for the District of Columbia Circuit a recent decision by FERC approving the implementation of a demand curve for the New York installed capacity, or ICAP, market. ECRC claims that the implementation of the ICAP demand curve violates section 205 of the

Federal Power Act because it constitutes unreasonable ratemaking. We are a party to this appeal and will contest ECRC's assertions, but at this time cannot assess what the eventual outcome will be.

Consolidated Edison Co. of New York v. Federal Energy Regulatory Commission, Docket No. 01-1503

Consolidated Edison and others petitioned the United States Court of Appeals for the District of Columbia Circuit for review of certain FERC orders in which FERC refused to order a redetermination of prices in the New York Independent System Operator, or NYISO, operating reserve markets for the period from January 29, 2000 to March 27, 2000. Petitioners alleged that the prices in the operating reserves markets were unduly elevated by approximately $65 million as a result of market power abuse and operating flaws. On November 7, 2003, the court issued a decision which found that the NYISO's method of pricing spinning reserves violated the NYISO tariff. The court also required FERC to determine whether the exclusion from the non-spinning market of a generating facility known as Blenheim-Gilboa and resources located in western New York also constituted a tariff violation and/or whether these exclusions enabled NYISO to use its Temporary Extraordinary Procedure, or TEP, authority to require refunds. On June 25, 2004, the NYISO filed a motion requesting that it be permitted to supplement the record. The motion indicated that FERC had the authority to order refunds in the case because the failure to model Blenhein-Gilboa constituted a TEP. On July 16, 2004, we filed an objection to the NYISO's motion, asserting that the failure to model was a conscious decision of the owners of that facility and that NYISO's authority under TEP did not apply. It is unclear at this time whether FERC will require refunds, much less the amount of any such refunds. If 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 will share responsibility for payment of such refunds, under the petitioners' theory and calculations the cumulative exposure to our above-listed entities could exceed $23 million.

Connecticut Light & Power Company v. NRG Power Marketing, Inc., Docket No. 3:01-CV-2373 (AWT), pending in the United States District Court, District of Connecticut

This matter involves a claim by CL&P for recovery of amounts it claims are owing for congestion charges under the terms of a SOS contract between the parties, dated October 29, 1999. CL&P has served and filed its motion for summary judgment to which PMI filed a response on March 21, 2003. CL&P has withheld approximately $30 million from amounts owed to PMI, claiming that it has the right to offset those amounts under the contract. PMI has counterclaimed seeking to recover those amounts, arguing among other things that CL&P has no rights under the contract to offset them. By reason of the previous bankruptcy stay, the court has not ruled on the pending motion. On November 6, 2003, the parties filed a joint stipulation for relief from the automatic stay in order to allow the proceeding to go forward and PMI is about to supplement the record on the pending summary judgment motion. PMI cannot estimate at this time the likelihood of an unfavorable outcome in this matter.

The State of New York and Erin M. Crotty, as Commissioner of the New York State Department of Environmental Conservation v. Niagara Mohawk Power Corporation, NRG Energy, Inc., NRG Dunkirk Operations, Inc., Dunkirk Power, LLC, NRG Huntley Operations, Inc., Huntley Power, LLC, NRG Northeast Generating, LLC, Northeast Generation Holding, LLC, NRG Eastern, LLC and NRG Operating Services, Inc., United States District Court for the Western District of New York, Civil Action No. 02-CV-0024S

In January 2002, the New York Department of Environmental Conservation, or DEC, sued Niagara Mohawk Power Corporation, or NiMo, us and certain of our affiliates in federal court in New York. The complaint asserted that projects undertaken at our Huntley and Dunkirk plants by NiMo, the former owner of the facilities, required preconstruction permits pursuant to the Clean Air Act and that the failure to obtain these permits violated federal and state laws. In July, 2002, we filed a motion to dismiss. On March 27, 2003, the court dismissed the complaint against us as to the federal claims and without prejudice as to the state claims. On December 31, 2003, the trial court granted the state's motion to amend the complaint to again sue us and various affiliates in this same action in the federal court in New York, asserting against us violations of operating permits and deficient operating permits at the Huntley and Dunkirk plants. The parties have commenced written discovery, and the court has scheduled the trial on liability issues for March, 2006. For several months, the parties have been engaged in discussions respecting possible settlement of this matter. If the case ultimately is litigated to an unfavorable outcome that could not be addressed otherwise, we have estimated that the total investment that would be required to install pollution control devices could be as high as $300 million over a ten to twelve-year period. We also could be found responsible for payment of certain penalties and fines.

Niagara Mohawk Power Corporation v. NRG Energy, Inc., Huntley Power, LLC, and Dunkirk Power, LLC, Supreme Court, State of New York, County of Onondaga, Case No. 2001-4372

We have asserted that NiMo is obligated to indemnify us for any related compliance costs associated with resolution of the above enforcement action. NiMo has filed suit in state court in New York seeking a declaratory judgment with respect to its obligations to indemnify us under the asset sales agreement. We have pending a summary judgment motion on our entitlement to be reimbursed by NiMo for the attorneys' fees we have incurred in the enforcement action.

Huntley Power LLC

On April 30, 2003, the Huntley Station submitted a self-disclosure letter to the DEC reporting violations of applicable sulfur in fuel limits, which had occurred during 6 days in March 2003 at the chimney stack serving Huntley Units 63-66. The Huntley Station self-disclosed that the average sulfur emissions rates for those days had been 1.8 lbs/mm BTU, rather than the maximum allowance of 1.7 lbs/mm BTU. NRG Huntley Operations discontinued use of Unit 65 (the only unit utilizing the subject stack at the time) and has kept the remaining three units off line until adherence with the applicable standard is assured. On May 19, 2003, the DEC issued Huntley Power LLC a Notice of Violation. Huntley Power LLC has met with the DEC to discuss the circumstances surrounding the event and the appropriate means of resolving the matter. Huntley Power LLC does not know what relief the DEC will seek through an enforcement action. Under applicable provisions of the Environmental Conservation Law, the DEC asserts that it may impose a civil penalty up to $10,000, plus an additional penalty not to exceed $10,000 for each day that a violation continues and may enjoin continuing violations.

Niagara Mohawk Power Corporation v. Dunkirk Power LLC, NRG Dunkirk Operations, Inc., Huntley Power LLC, NRG Huntley Operations, Inc., Oswego Power LLC and NRG Oswego Operations, Inc., Supreme Court, Erie County, Index No. 1-2000-8681 — Station Service Dispute ;

On October 2, 2000, plaintiff Niagara Mohawk Power Corporation, or NiMo, commenced this action against us to recover damages plus late fees, less payments received through the date of judgment, as well as any additional amounts due and owing, for electric service provided to the Dunkirk Plant after September 18, 2000. NiMo claims that we have failed to pay retail tariff amounts for utility services commencing on or about June 11, 1999. Plaintiff has alleged breach of contract, suit on account, violation of statutory duty and unjust enrichment claims. On or about October 23, 2000, we served an answer denying liability and asserting affirmative defenses.

After proceeding through discovery, and prior to trial, the parties and the court entered into a Stipulation and Order filed August 9, 2002 consolidating this action with two other actions against our Huntley and Oswego subsidiaries, both of which cases assert the same claims and legal theories for failure to pay retail tariffs for utility services at those plants.

On October 8, 2002, a Stipulation and Order was filed in the Erie County Clerk's Office staying this action pending submission to FERC of some or all of these disputes. We cannot make an evaluation of the likelihood of an unfavorable outcome. The cumulative potential loss could amount to some $40 million.

Niagara Mohawk Power Corporation v. Huntley Power LLC, NRG Huntley Operations, Inc., NRG Dunkirk Operations, Inc., Dunkirk Power LLC, Oswego Harbor Power LLC, and NRG Oswego Operations, Inc., Case Filed November 26, 2002 in Federal Energy Regulatory Commission Docket No. EL 03-27-000

This is the companion action filed by NiMo at FERC, similarly asserting that NiMo is entitled to receive retail tariff amounts for electric service provided to the Huntley, Dunkirk and Oswego plants. On October 31, 2003, the FERC Trial Staff, a party to the proceedings, filed a reply brief in which it supported and agreed with each position taken by our facilities. In short, the staff argued that our facilities: (1) self-supply station power under the NYISO tariff (which took effect on April 1, 2003) in any month during which they produce more energy than they consume and, as such, should not be assessed a retail rate; (2) are connected only to transmission facilities and, as such, at most should only pay NiMo a FERC-approved transmission rate; and (3) should be allowed to net consumption and output even if power is injected into the grid at a different point from which it is drawn off. We are presently awaiting a ruling by FERC. At this stage of the proceedings, we cannot estimate the likelihood of success on this action. As noted above, the cumulative potential loss could amount to some $40 million.

In the Matter of Louisiana Generating, LLC, Adversary Proceeding No. 2002-1095 1-EQ on the docket of the Louisiana Division of Administrative Law

During 2000, the Louisiana Department of Environmental Quality, or DEQ, issued a Part 70 Air Permit modification to Louisiana Generating to construct and operate two 240 MW natural gas-fired turbines. The Part 70 Air Permit set emissions limits for the criteria air pollutants, including NO(x), based on the application of Best Available Control Technology, or BACT. The BACT limitation for NO(x) was based on the guarantees of the manufacturer, Siemens-Westinghouse. Louisiana Generating sought an interim emissions limit to allow Siemens-Westinghouse time to install additional control equipment. To establish the interim limit, DEQ issued a

Compliance Order and Notice of Potential Penalty, No. AE-CN-02-0022, on September 8, 2002, which is, in part, subject to the above-referenced administrative hearing. DEQ alleged that Louisiana Generating did not meet its NO(x) emissions limit on certain days, did not conduct all opacity monitoring and did not complete all record keeping and certification requirements. Louisiana Generating intends to vigorously defend certain claims and any future penalty assessment, while also seeking an amendment of its limit for NO(x). An initial status conference was held with the Administrative Law Judge and quarterly reports are being submitted to that judge to describe progress, including settlement and amendment of the limit. In late February 2004, we timely submitted to the DEQ an amended BACT analysis and amended Prevention of Significant Deterioration and Title V permit application to amend the NO(x) limit. The DEQ is presently processing the permit application. In addition, Louisiana Generating may assert breach of warranty claims against the manufacturer. With respect to the administrative action described above, at this time we are unable to predict the eventual outcome of this matter or the potential loss contingencies, if any, to which we may be subject.

United States Environmental Protection Agency Request for Information under Section 114 of the Clean Air Act

On January 27, 2004, Louisiana Generating, LLC and Big Cajun II received a request for information under Section 114 of the Clean Air Act from the United States Environmental Protection Agency, or EPA, seeking information primarily relating to physical changes made at Big Cajun II in 1994 and 1995 by the predecessor owner of that facility. Louisiana Generating, LLC and Big Cajun II have been responding to the EPA request in an appropriate manner. At the present time, we cannot predict the probable outcome in this matter.

Itiquira Energetica, S.A.

Our indirectly controlled Brazilian project company, Itiquira Energetica S.A., the owner of a 156 MW hydro project in Brazil, is currently 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 principally asserts that Inepar breached the contract and caused damages to Itiquira by (i) failing to meet milestones for substantial completion; (ii) failing to provide adequate resources to meet such milestones; (iii) failing to pay subcontractors amounts due; and (iv) being insolvent. Itiquira’s arbitration claim is for approximately U.S. $40 million. Inepar has asserted in the arbitration that Itiquira breached the contact and caused damages to Inepar by failing to recognize events of force majeure as grounds for excused delay and extensions of scope of services and material under the contract. Inepar’s damage claim is for approximately U.S. $10 million. The parties submitted their respective statements of claims, counterclaims and responses, and a preliminary arbitration hearing was held on March 21, 2003. In lieu of taking expert testimony at hearing, the court of arbitration ordered an expert investigation process to cover technical and accounting issues. The final report from the expert investigation process has been delivered to the court of arbitration. Expert testimony will be presented at a hearing scheduled for mid-August, 2004, and we expect the court to issue its decision shortly after the hearing. We cannot estimate the likelihood of an unfavorable outcome in this dispute.

CFTC Trading Inquiry

On June 17, 2002, the CFTC served Xcel Energy, on behalf of its affiliates, which then included us and PMI, with a subpoena requesting certain information regarding “round trip” or “wash” trading and general trading practices in its investigation of several energy trading companies. The CFTC later focused on possible efforts by traders to submit false reports to gas index publications in an attempt to manipulate the index. In January, 2004, the CFTC and Xcel Energy’s subsidiary, e prime, inc., reached a settlement in connection with this investigation, which included the payment of a $16 million fine and the entry of a cease and desist order. Other industry participants that have settled with the CFTC have paid fines of between $1.5 million and $28 million and have agreed to the terms of cease and desist orders. The CFTC requested additional related information from us and subpoenaed to appear for testimony a number of our present and former employees. We cooperated with the CFTC and submitted materials responsive to the CFTC’s requests, while vigorously denying that we engaged in any improper conduct. On July 1, 2004, we learned that the CFTC had filed a civil complaint against us in Minnesota federal district court, alleging that we engaged in false reporting of natural gas trades from August, 2001 to May, 2002. The CFTC’s complaint seeks only an injunction against future violations of the Commodity Exchange Act. We cannot at this time predict the outcome of this matter.

General Electric Company and Siemens Westinghouse Turbine Purchase Disputes

We and/or our affiliates have entered into several turbine purchase agreements with affiliates of General Electric Company, or GE, and Siemens Westinghouse Power Corporation, or Siemens. GE and Siemens have notified us that we are in default under certain of those contracts, terminated such contracts, and demanded that we pay the termination fees set forth in such contracts. GE’s claim amounts to approximately $113 million and Siemens’ approximately $45 million in cumulative termination charges. Most of these disputes fall within the NRG plan of reorganization and are subject to our disputed claims reserves, discussed below. In early July, 2004, we reached an agreement in principle with GE resolving the disputed bankruptcy claims of GE and its subsidiaries. The parties are now preparing final documentation of the settlement. We cannot estimate the likelihood of an unfavorable outcome in our disputes with Siemens.

Additional Litigation

In addition to the foregoing, we are parties to other litigation or legal proceedings, which may or may not be material. There can be no assurance that the outcome of such matters will not have a material adverse effect on our business, financial condition or results of operations.

Disputed Claims Reserve

As part of the NRG plan of reorganization, 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 claim reserve, we are obligated to provide additional cash 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 provided our common stock and cash contribution 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 have removed the obligations relevant to the claims from our balance sheet when the common stock was issued and cash contributed.

In conjunction with confirmation of the NRG plan of reorganization, we reached an agreement with the Attorney General and the State of California that limits the potential maximum amount of its claims, if any. Under the NRG plan of reorganization, the liquidated amount of any allowed claims shall not exceed $1.35 billion in total. The agreement neither affects our right to object to these claims on any grounds nor admits any liability. We further agreed to waive any objection to the liquidation of these claims in a non-bankruptcy forum having proper jurisdiction. Although we cannot at this time make any evaluation of the likelihood of an unfavorable outcome or an estimate of the amount or range of potential loss in the private actions and various investigations, we note that the Gordon complaint, discussed above, alleges that the defendants, collectively, overcharged California ratepayers during 2000 by $4.0 billion.

Regulatory Issues

New England

Consistent with expectations, the Peaking Unit Safe Harbor, or PUSH, bidding has not yielded sufficient revenues to cover all costs for most of the Company's affected facilities. On January 16, 2004, the Company filed proposed reliability-must-run agreements, or RMR agreements, with FERC for the following facilities: Devon station units 11 – 14, Middletown station and Montville station. The RMR agreement filings requested FERC to establish cost of service rates. On March 18, 2004 FERC granted us a one day suspension of the rates, subject to refund, set the case for hearing and consolidated the case with other similar NRG cases before a settlement judge. In the March 18, 2004 order the FERC ruled that the RMR agreements would expire with the implementation of a locational installed capacity, or LICAP, market, which was expected to begin on June 1, 2004. On April 14, 2004 we filed a motion for rehearing with FERC requesting FERC to revise the termination date ruling. As of this date, FERC has not responded to the rehearing request.

Prior to the March 18, 2004 order, Devon 11 – 14, Middletown 4 and Montville had been submitting PUSH bids. As a result of the March 18, 2004 order we received more money from the sale of energy and capacity for the period January 17, 2004 through March 18, 2004 than was allowed under the March 18, 2004 order. Therefore, on June 23, 2004, we filed a report (" Report") with the FERC showing that we received approximately $4.9 million more from the sales of energy and other services than was permitted under the March 18th order. The Report further stated, however, that ISO-NE owed us a total of approximately $18.5 million under the RMR Agreement for the same period. The Report further stated that ISO-NE had, as of the date of the Report, paid us only $2.6 million, with the result that we, rather than owing any refunds to ISO-NE, were owed an additional $11.0 million for the period. The FERC has not yet acted on the Report.

On February 6, 2004, we filed updated maintenance schedules for the tracking mechanism that provides for the payment by certain NEPOOL participants of third party maintenance expense incurred by Devon 11 – 14, Middletown, Montville and Norwalk Harbor for the period beginning April 1, 2004 and ending March 31, 2005. On April 1, 2004 FERC accepted the revised schedules, subject to refund, set the case for hearing and consolidated the case with other similar NRG cases before a settlement judge. In the April 1, 2004 order the FERC ruled that the tracking mechanism would expire with the implementation of a LICAP market, which is expected to begin on June 1, 2004. On April 14, 2004 we filed a motion for rehearing with FERC requesting FERC to revise the termination date ruling. As of this date, FERC has not responded to the rehearing request.

On April 1, 2004, we filed with FERC true-up schedules for the third-party payment of our maintenance expenses for the period February 27, 2003 to December 31, 2003. On July 12, 2004 FERC accepted the true-up schedules, effective June 7, 2004, subject to refund, set them for hearing and consolidated the case with other similar cases before a settlement judge.

In addition to the facilities noted above, the following of the Company's quick-start facilities in Connecticut have submitted PUSH bids that have been approved by FERC: Cos Cob, Franklin Drive, Banford and Torrington. The existing RMR agreement between ISO-NE and the Company covering Devon station units 7 and 8 terminated on September 30, 2003. On October 2, 2003, the Company filed with FERC to extend the existing RMR agreement for the two Devon units. On December 1, 2003, FERC granted a one-day suspension of the rates, subject to refund, set the case for hearing and appointed a settlement judge. On February 25, 2004, a FERC sponsored technical conference occurred to review the costs associated with the two Devon units. In the technical conference, the costs relevant to the RMR agreements were discussed. ISO-NE has indicated in a letter dated February 27, 2004, that one of the Devon units will no longer be needed for reliability services.

Therefore, on May 28, 2004, Devon 8 was deactivated. On May 28, 2004, a revised RMR agreement was filed with FERC for Devon 7 facility to account for the costs remaining after the deactivation of Devon 8. On July 12, 2004, FERC granted us a one day suspension of the proposed rate of $10.15 per KW-month subject to refund, set the case for hearing and consolidated the case with other similar NRG cases before a settlement judge.

On March 1, 2004, ISO-NE filed a locational capacity proposal with FERC. Under the proposal, generators that are needed for reliability and have a capacity factor of 15% or less in 2003 would be eligible for a monthly capacity payment of $5.38 per KW-month. Most of the Company's generators located in Connecticut satisfy this requirement. On June 2, 2004, FERC issued an order rejecting ISO-NE's LICAP proposal. In the order, the FERC ruled that LICAP would not go into effect until January 1, 2006. Until the implementation of LICAP, the existing PUSH bidding rules and existing RMR agreements are to continue. New RMR agreements must also end when the LICAP market is implemented.

New York

In April of 2003, the 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. In a complaint filed with FERC on December 15, 2003, Consolidated Edison Company of New York, Inc. and other load-serving entities alleged that NYISO had used the wrong rate setting methodology to establish prices and rebates in the New York City markets for a portion of the summer capacity auction in 2003, and that this action resulted in overcharges to customers and overpayments to suppliers, including the Company, totaling approximately $21 million, with the Company's share being approximately $5 million. On July 13, 2004, FERC denied the complaint.

PJM

On April 2, 2003, Reliant Resources, Inc., or Reliant, filed a complaint against the Pennsylvania, Jersey, Maryland Interconnector area, or PJM, with FERC and suggested specific modifications to PJM's price mitigation rules. On June 9, 2003, FERC rejected the Reliant modifications but required PJM to file a report to address the concerns of Reliant by September 30, 2003. The PJM market monitoring unit filed its compliance filing with FERC as required, but opted to continue its present mitigation practices. The present mitigation plan permits PJM to "cost-cap" the energy bids of certain generating facilities that were constructed prior to 1996. The cost capping method is based on a facility's variable costs plus 10%. In addition, the PJM market monitoring unit filed to eliminate the exemption that units built after 1996 had from PJM's mitigation measures. On May 6, 2004, FERC rejected the proposed extension of the cost capping mechanism to generating facilities built after 1996. In the order, the FERC approved the application of cost-capping mitigation method for facilities built prior to 1996 and were cost capped less than 80% of the time the facilities operated. The FERC required that for facilities that are cost capped 80% or more of their operating hours that are mitigated, are needed for reliability and are not recovering sufficient revenue to cover their costs, that PJM must provide alternative methods of compensation. The FERC noted that such alternative compensation could consist of market design changes such as a higher bid cap or reliability must run agreements. FERC required that PJM file such a proposal by November 6, 2004. At this time it is unclear how this ruling will impact the Company. The Company continues to monitor these activities for any potential adverse impact to the Company's financial position or results of operations.

PJM – West

On December 31, 2003 and February 5, 2004, PJM filed proposed mitigation plans for the Commonwealth Edison, or Com Ed, franchise territory. Among the proposed changes was the adoption of the existing PJM energy market mitigation plan of "cost capping" and a new mitigation plan for the capacity market. PJM proposed that the proposed energy market mitigation plan would only be effective through the 2004 summer season but that the capacity mitigation plan would remain effective until April 1, 2005. Under the capacity mitigation proposal, capacity prices would be capped at $30 per MW-day except when capacity levels are less than 101% of required reserves, then the price cap would be $160 per MW-day. On March 24, 2004, FERC rejected the proposed mitigation plans. On April 23, 2004, PJM filed a rehearing request on the rejection of the capacity market mitigation proposal. In the rehearing request, PJM requested that the $30 per MW-day cap be approved and that during times of scarcity there would not be a price cap. FERC has not yet issued an order on the rehearing request.

On May 1, 2004 Commonwealth Edison Corporation became a member of PJM.

Entergy

On March 31, 2004, Entergy filed with FERC a proposal to have an independent person monitor Entergy's operation of its transmission system. FERC has not ruled on this request. Also, it is unclear at this time how this recent development will impact the Company.

Note 18 — Guarantees

In November 2002, the FASB issued FASB Interpretation, or FIN, No. 45, *"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."* The initial recognition and initial measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year-end. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. The interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. The interpretation also clarifies the requirements related to the recognition of a liability by a guarantor at the inception of the guarantee for the obligations the guarantor has undertaken in issuing the guarantee.

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 those guarantees. Each guarantee was reviewed for the requirement to recognize a liability at inception.

In the normal course of business, we may be asked to provide certain assurances to the counter-parties of our asset sales agreements, such assurances may take the form of a guarantee issued by NRG on behalf of a directly or indirectly held majority-owned subsidiary. Due to the inter-company nature of such arrangements (NRG is essentially guaranteeing its own performance) and the nature of the guarantee being provided (usually the typical representations and warrantees that are provided in any asset sales agreement), it is not our policy to recognize the value of such an obligation in our consolidated financial statements.

In connection with the adoption of Fresh Start, all outstanding guarantees were considered new; accordingly we applied the provisions of FIN 45 to all those guarantees. Each guarantee was reviewed for the requirement to recognize a liability at inception. As a result, we recorded a $15.0 million liability, which is included in other long-term liabilities.

We are directly liable for the obligations of certain of our project affiliates and other subsidiaries pursuant to guarantees relating to certain of their indebtedness, equity and operating obligations. In addition, in connection with the purchase and sale of fuel, emission credits and power generation products to and from third parties with respect to the operation of some of our generation facilities in the United States, we may be required to guarantee a portion of the obligations of certain of our subsidiaries.

As of June 30, 2004, our obligations pursuant to our guarantees of the performance, equity and indebtedness obligations of our subsidiaries were as follows (includes only quantifiable amounts):

Description	June 30, 2004
	(In thousands)
Guarantees of subsidiaries	$ 511,066
Guarantees of NRG Power Marketing, Inc. obligations	38,500
Total	$ 549,566

As of June 30, 2004, the nature and details of our guarantees were as follows:

Project or Subsidiary	Maximum Amount (June 30, 2004) (In thousands)	Nature of Guarantee	Expiration	Triggering Event
Astoria/Arthur Kill	Indeterminate	Performance Under Asset Purchase Agreement	None stated	Non-performance
Cobee	$ 12,500	Guarantee of Obligations Under the Sale and Purchase Agreement	April 27, 2008	Non-performance or non-payment
Elk River	$ 11,990	Executory Contract	Undetermined	Non-payment
Flinders	$ 6,357	Fund Superannuation (Pension) Reserve	September 8, 2012	Credit agreement default
Flinders	$ 48,951	Debt Service Reserve Guaranty	September 8, 2012	Credit agreement default
Flinders	$ 57,736	Plant Removal and Site Remediation Obligation	Undetermined	Non-performance
Flinders	$ 69,930	Guaranty of Employee Separation Benefits	None stated	Non-payment
Flinders	Indeterminate	Indemnification of Government Entity for Payment for Power and Fuel	Fourth quarter 2018	Non-payment
Flinders	$ 218,907	Guaranty of Obligation to Purchase Gas	None stated	Non-payment
Gladstone	$ 22,819	Payment of Penalties in the Event of an Extraordinary Operational Breach	None stated	Non-performance
Gladstone	Indeterminate	Performance Obligations under Credit Agreement	March 31, 2009	Non-performance
Hsin Yu	$ 1,000	Guarantee of Obligations Under the Sale and Purchase Agreement	None stated	Non-performance or non-payment
Latin Power	Indeterminate	Subscription Commitment Guaranty	None stated	Non-performance
Loy Yang	$ 25,370	Guarantee of Obligations Under the Sale and Purchase Agreement	April 7, 2011	Non-performance or non-payment
McClain	$ 1,015	Obligation to Fund Debt Service Reserve Shortfall	None stated	Non-payment
MIBRAG	$ 8,314	Guarantee of Share Purchase Agreement	None stated	Non-performance
Newport	$ 7,500	Executory Contract	Undetermined	Non-payment
Other	$ 17,933	Various	Various	Various
PMI	$ 38,500	Guarantee on behalf of NRG Power Marketing Inc. for various projects	Various	Non-performance
West Coast LLC	$ 744	Guaranty of Environmental Cleanup Costs	None stated	Non-performance
West Coast LLC	Indeterminate	Continuing Obligations Under Asset Sales Agreement and Related Contracts	None stated	Non-performance
Total	$ 549,566			

Recourse provisions for each of the guarantees above are to the extent of their respective liability. No assets are held as collateral for any of the above guarantees.

Note 19 — Benefit Plans and Other Postretirement Benefits

Reorganized NRG

Substantially all of our employees participate in defined benefit pension plans. We have initiated a new 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. We have contributed $1.0 million to the NRG pension plans during the six months ended June 30, 2004. We expect to contribute approximately $1.0 million to our postretirement medical plan in 2004.

NRG Pension and Postretirement Medical Plans

Components of Net Periodic Benefit Cost

The net annual periodic pension cost related to all of our plans, include the following components:

	Pension Benefits			
	Reorganized NRG	Predecessor Company	Reorganized NRG	Predecessor Company
	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands)			
Service cost benefits earned	**$ 2,950**	$ —	**$ 5,900**	**$ —**
Interest cost on benefit obligation	**738**	—	**1,476**	—
Amortization of prior service cost	—	—	—	—
Expected return on plan assets	—	—	—	—
Recognized actuarial (gain)/loss	—	—	—	—
Net periodic benefit cost	**$ 3,688**	$ —	**$ 7,376**	$ —

	Other Benefits			
	Reorganized NRG	Predecessor Company	Reorganized NRG	Predecessor Company
	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands)			
Service cost benefits earned	**$ 465**	$ 334	**$ 930**	$ 668
Interest cost on benefit obligation	**630**	525	**1,260**	1,050
Amortization of prior service cost	—	(6)	—	(12)
Expected return on plan assets	—	—	—	—
Recognized actuarial (gain)/loss	—	48	—	96
Net periodic benefit cost	**$ 1,095**	$ 901	**$ 2,190**	$ 1,802

2003 Medicare Legislation

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003, the Act, became law in the United States. The Act introduces a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the Medicare benefit. In accordance with FASB Staff Position FAS 106-1, "*Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*", we have elected to defer recognition of the effects of the Act in any measures of the benefit obligation or cost. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require the Company to change previously reported information. Currently, we do not believe we will need to amend the postretirement benefit plans to benefit from the Act. The measurement date used to determine pension and other postretirement benefit measures for the plans is December 31.

Note 20 — Creditor Pool and Other Settlements

A principal component of our plan of reorganization is a settlement with Xcel Energy in which Xcel Energy agreed to make a contribution consisting of cash (and, under certain circumstances, its stock) in the aggregate amount of up to $640 million to be paid in three separate installments following the effective date of our plan of reorganization. The Xcel Energy settlement agreement resolves any and all claims existing between Xcel Energy and us and/or our creditors and, in exchange for the Xcel Energy contribution, Xcel Energy is receiving a complete release of claims from us and our creditors, except for a limited number of creditors who have preserved their claims as set forth in the confirmation order entered on November 24, 2003. On February 20, 2004, we received $288 million from Xcel Energy. On April 30, 2004 we received $328.5 million from Xcel Energy as part of the third settlement payment. The remainder of the third settlement payment, $23.5 million, was paid by Xcel Energy on May 28, 2004. We used the proceeds from the Xcel Energy settlement to reduce our creditor pool obligation. As of June 30, 2004 and December 31, 2003 the balance of our creditor pool obligation was $25.0 million and $540.0 million, respectively. On February 20, 2004, April 30, 2004 and May 28, 2004, we made payments of $163.0 million, $328.5 million and $23.5 million, respectively. In addition, our other bankruptcy settlement obligation as of June 30, 2004 and December 31, 2003 was $221.3 million and $220.0 million, respectively. This obligation relates to the allowed claims pending against our Audrain and Pike facilities. The net change in the balance of $1.3 million as of June 30, 2004 relates to a $2.6 million increase to the outstanding obligation offset by an increase of $1.3 million related to an agreement whereby we are entitled to reimbursement of certain costs incurred while we are maintaining these facilities in anticipation of their sale whereupon any proceeds will be turned over to the creditors.

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Note 21 — Condensed Consolidating Financial Information

On December 17, 2003 and January 28, 2004, we issued $1.2 billion and $475.0 million, respectively, of 8% Second Priority Senior Secured Notes due on December 15, 2013, or the Notes. These Notes are guaranteed by each of our current and future wholly owned domestic subsidiaries, or Guarantor Subsidiaries. Each of the following Guarantor Subsidiaries fully and unconditionally guarantee the Notes.

Arthur Kill Power LLC
Astoria Gas Turbine Power LLC
Berrians I Gas Turbine Power LLC
Big Cajun II Unit 4 LLC
Capistrano Cogeneration Company
Chickahominy River Energy Corp.
Commonwealth Atlantic Power LLC
Conemaugh Power LLC
Connecticut Jet Power LLC
Devon Power LLC
Dunkirk Power LLC
Eastern Sierra Energy Company
El Segundo Power II LLC
Hanover Energy Company
Huntley Power LLC.
Indian River Operations Inc.
Indian River Power LLC
James River Power LLC
Kaufman Cogen LP
Keystone Power LLC
Louisiana Generating LLC
MidAtlantic Generation Holding 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.
Northeast Generation Holding LLC
Norwalk Power LLC
NRG Affiliate Services Inc.
NRG Arthur Kill Operations Inc.
NRG Asia-Pacific, Ltd.
NRG Astoria Gas Turbine Operations ,Inc.
NRG Bayou Cove LLC
NRG Cabrillo Power Operations Inc.
NRG Cadillac Operations Inc.
NRG California Peaker Operations LLC
NRG Central U.S. LLC
NRG Connecticut Affiliate Services Inc.
NRG Devon Operations Inc.
NRG Dunkirk Operations Inc.
NRG Eastern LLC
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 MidAtlantic LLC
NRG Middletown Operations Inc.
NRG Montville Operations Inc.
NRG New Jersey Energy Sales LLC
NRG New Roads Holdings LLC
NRG North Central Operations Inc.
NRG Northeast Affiliate Services Inc.
NRG Northeast Generating LLC
NRG Norwalk Harbor Operations Inc.
NRG Operating Services, Inc.
NRG Oswego Harbor Power Operations Inc.
NRG Power Marketing Inc.
NRG Rocky Road LLC
NRG Saguaro Operations Inc.
NRG South Central Affiliate Services Inc.
NRG South Central Generating LLC
NRG South Central Operations Inc.
NRG West Coast LLC
NRG Western Affiliate Services Inc.
Oswego Harbor Power LLC
Saguaro Power LLC
Somerset Operations Inc.
Somerset Power LLC
South Central Generation Holding 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 Six Months Ended June 30, 2004
Reorganized NRG
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$848,258	$ 303,458	$ 26,026	$ (3,750)	$ 1,173,992
Operating Costs and Expenses					
Cost of majority-owned operations	520,126	204,139	15,286	(3,750)	735,801
Depreciation and amortization	66,389	35,284	6,501	—	108,174
General, administrative and development	46,391	14,925	21,013	—	82,329
Corporate relocation charges	—	—	6,761	—	6,761
Reorganization items	874	151	2,564	—	3,589
Restructuring and impairment charges	1,965	—	(289)	—	1,676
Total operating costs and expenses	635,745	254,499	51,836	(3,750)	938,330
Operating Income/(Loss)	212,513	48,959	(25,810)	—	235,662
Other Income (Expense)					
Minority interest in earnings of consolidated subsidiaries	—	(709)	—	—	(709)
Equity in earnings of consolidated subsidiaries	46,941	—	155,365	(202,306)	—
Equity in earnings/(losses) of unconsolidated affiliates	34,556	30,066	(808)	—	63,814
Write downs and gains/(losses) on sales of equity method investments	—	(1,271)	738	—	(533)
Other income, net	3,660	12,357	2,713	(7,022)	11,708
Interest expense	587	(48,252)	(118,728)	7,022	(159,371)
Total other income/(expense)	85,744	(7,809)	39,280	(202,306)	(85,091)
Income From Continuing Operations Before Income Taxes	298,257	41,150	13,470	(202,306)	150,571
Income Tax Expense (Benefit)	139,481	10,910	(99,789)	—	50,602
Income/(Loss) From Continuing Operations	158,776	30,240	113,259	(202,306)	99,969
Income/(Loss) on Discontinued Operations, net of Income Taxes	(2)	13,292	—	—	13,290
Net Income	$158,774	$ 43,532	$ 113,259	$ (202,306)	$ 113,259

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

NRG Energy, Inc. and Subsidiaries
Consolidating Statements of Operations
For the Three Months Ended June 30, 2004
Reorganized NRG
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc.	Eliminations (1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$421,748	$ 139,985	$ 14,019	$ (2,078)	$ 573,674
Operating Costs and Expenses					
Cost of majority-owned operations	248,080	100,127	7,621	(2,078)	353,750
Depreciation and amortization	31,493	17,866	3,809	—	53,168
General, administrative and development	26,543	9,217	10,077	—	45,837
Corporate relocation charges	—	—	5,645	—	5,645
Reorganization items	(859)	1	(1,803)	—	(2,661)
Restructuring and impairment charges	1,967	(3)	(288)	—	1,676
Total operating costs and expenses	307,224	127,208	25,061	(2,078)	457,415
Operating Income/(Loss)	114,524	12,777	(11,042)	—	116,259
Other Income (Expense)					
Minority interest in (earnings)/losses of consolidated subsidiaries	(508)	307	—	—	(201)
Equity in earnings of consolidated subsidiaries	25,165	—	99,404	(124,569)	—
Equity in earnings/(losses) of unconsolidated affiliates	26,672	19,412	17	—	46,101
Gains on sales of equity method investments	—	702	503	—	1,205
Other income, net	3,467	9,580	1,935	(6,930)	8,052
Interest expense	(132)	(28,001)	(45,022)	6,930	(66,225)
Total other income (expense)	54,664	2,000	56,837	(124,569)	(11,068)
Income From Continuing Operations Before Income Taxes	169,188	14,777	45,795	(124,569)	105,191
Income Tax Expense (Benefit)	68,514	5,037	(37,229)	—	36,322
Income From Continuing Operations	100,674	9,740	83,024	(124,569)	68,869
Income/(Loss) on Discontinued Operations, net of Income Taxes	(2)	14,157	—	—	14,155
Net Income/(Loss)	$100,672	$ 23,897	$ 83,024	$ (124,569)	$ 83,024

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

NRG Energy, Inc. and Subsidiaries
Consolidating Balance Sheets
at June 30, 2004
Reorganized NRG
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ 267,405	$ 202,187	$ 351,284	$ —	$ 820,876
Restricted cash	15,673	136,000	—	—	151,673
Accounts receivable trade, net	219,394	79,816	14,439	—	313,649
Current portion of notes receivable — affiliates	700	3,053	8,874	(10,710)	1,917
Current portion of notes receivable	—	122,773	287	—	123,060
Taxes receivable	—	—	35	14,789	14,824
Inventory	173,713	28,631	1,328	—	203,672
Derivative instruments valuation	11,670	—	—	—	11,670
Prepayments and other current assets	129,468	100,142	33,506	(33,155)	229,961
Current deferred income taxes	(506)	2,900	—	(1,433)	961
Current assets — discontinued operations	—	56,955	—	—	56,955
Total current assets	817,517	732,457	409,753	(30,509)	1,929,218
Property, Plant and Equipment					
In service	2,288,658	1,611,832	35,425	—	3,935,915
Under construction	64,105	39,897	792	—	104,794
Total property, plant and equipment	2,352,763	1,651,729	36,217	—	4,040,709
Less accumulated depreciation	(73,508)	(38,732)	(7,247)	—	(119,487)
Net property, plant and equipment	2,279,255	1,612,997	28,970	—	3,921,222
Other Assets					
Investments in subsidiaries	652,395	—	4,223,083	(4,875,478)	—
Equity investments in affiliates	360,345	316,950	389	—	677,684
Notes receivable, less current portion — affiliates	14,710	347,892	—	(240,063)	122,539
Notes receivable, less current portion	379,838	197,003	1,277	34,000	612,118
Intangible assets, net	301,791	54,277	—	—	356,068
Debt issuance costs, net	—	—	63,038	—	63,038
Derivative instruments valuation	1,724	46,070	5,680	—	53,474
Deferred income tax	179,525	—	158,274	(337,799)	—
Funded letter of credit	—	—	250,000	—	250,000
Other assets	34,738	25,880	55,511	—	116,129
Non-current assets — discontinued operations	—	451,785	—	—	451,785
Total other assets	1,925,066	1,439,857	4,757,252	(5,419,340)	2,702,835
Total Assets	$5,021,838	$ 3,785,311	$ 5,195,975	$ (5,449,849)	$ 8,553,275

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

NRG Energy, Inc. and Subsidiaries
Consolidating Balance Sheets
at June 30, 2004
Reorganized NRG
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 2,449	$ 94,795	$ 9,851	$ (10,710)	$ 96,385
Short-term debt	—	17,826	—	—	17,826
Accounts payable — trade	43,627	86,128	7,278	—	137,033
Accounts payable — affiliates	105,689	(201,737)	109,788	(7,368)	6,372
Accrued property, sales and other taxes	4,048	10,951	1,137	—	16,136
Accrued salaries, benefits and related costs	18,056	11,112	3,904	—	33,072
Accrued interest	3	46,262	6,928	(33,155)	20,038
Derivative instruments valuation	20,979	—	—	—	20,979
Creditor pool obligation	—	—	25,000	—	25,000
Other bankruptcy settlement	—	221,283	—	—	221,283
Other current liabilities	77,637	15,210	23,576	(2,650)	113,773
Current liabilities — discontinued operations	—	23,121	—	—	23,121
Total current liabilities	272,488	324,951	187,462	(53,883)	731,018
Other Liabilities					
Long term debt and capital leases	10,664	1,739,059	2,412,757	(240,063)	3,922,417
Non-current deferred income tax liability	—	147,051	—	(2,529)	144,522
Postretirement and other benefit obligations	84,452	13,788	12,602	—	110,842
Derivative instruments valuation	—	127,894	31,673	—	159,567
Other long-term obligations	348,833	109,011	15,403	—	473,247
Non-current liabilities — discontinued operations	—	469,911	—	—	469,911
Total non-current liabilities	443,949	2,606,714	2,472,435	(242,592)	5,280,506
Total Liabilities	716,437	2,931,665	2,659,897	(296,475)	6,011,524
Minority Interest	—	5,673	—	—	5,673
Commitments and Contingencies					
Stockholders' Equity	4,305,401	847,973	2,536,078	(5,153,374)	2,536,078
Total Liabilities and Stockholders' Equity	$5,021,838	$ 3,785,311	$ 5,195,975	$ (5,449,849)	$ 8,553,275

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

NRG Energy, Inc. and Subsidiaries
Consolidating Statements of Cash Flows
For the Six Months Ended June 30, 2004
Reorganized NRG
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income	$ 158,774	$ 43,532	$ 113,259	$ (202,306)	$ 113,259
Adjustments to reconcile net income to net cash provided (used) by operating activities					
Distributions in excess of (less than) equity in earnings of unconsolidated affiliates	(16,936)	(26,176)	(147,171)	195,034	4,751
Depreciation and amortization	66,389	40,609	6,501	—	113,499
Amortization of debt issuance costs	—	211	19,849	—	20,060
Amortization of debt discount	(27,672)	21,356	(2,149)	20,260	11,795
Deferred income taxes	(6,799)	1,828	(139,625)	193,980	49,384
Non-cash contribution from members — current taxes	119,312	40,721	—	(160,033)	—
Minority interest	—	2,089	—	—	2,089
Unrealized (gains)/losses on derivatives	(32,122)	(46,084)	4,049	52,699	(21,458)
Asset impairment	1,676	—	—	—	1,676
Write downs and (gains)/losses on sales of equity method investments	—	1,268	(735)	—	533
Gain on sale of discontinued operations	—	(13,012)	—	—	(13,012)
Amortization of power contracts and emission credits	11,705	22,812	—	—	34,517
Cash provided (used) by changes in certain working capital items, net of acquisition affects					
Accounts receivable	(98,983)	(10,991)	(1,080)	—	(111,054)
Xcel Energy settlement receivable	—	—	640,000	—	640,000
Accrued taxes	—	—	39	(29,324)	(29,285)
Inventory	(8,860)	515	(94)	—	(8,439)
Prepayments and other current assets	(42,797)	(36,224)	44,757	32,199	(2,065)
Accounts payable	4,249	(24,764)	(7,111)	—	(27,626)
Accounts payable — affiliates	(340,305)	1,514	209,251	129,753	213
Accrued property, sales and other taxes	(3,184)	(3,084)	(797)	—	(7,065)
Accrued salaries, benefits and related costs	12,492	4,082	3,618	—	20,192
Accrued interest	(2,554)	47,209	2,427	(32,199)	14,883
Other current liabilities	7,386	(709)	(513,045)	—	(506,368)
Cash (provided)/used by changes in other assets and liabilities	46,045	(6,182)	103,297	(126,282)	16,878
Net Cash Provided (Used) by Operating Activities	(152,184)	60,520	335,240	73,781	317,357
Cash Flows from Investing Activities					

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
Proceeds on sale of equity method investments	—	26,693	3,000	—	29,693
Proceeds on sale of discontinued operations	—	59,190	—	—	59,190
Investments in subsidiaries	(17,642)	48,979	(256,230)	224,893	—
Investments in equity method investments and projects	55,573	(64,861)	287,136	(278,414)	(566)
Decrease in notes receivable, net	49,687	187,260	22,296	(244,035)	15,208
Capital expenditures	(43,882)	(19,839)	(955)	—	(64,676)
Increase in restricted cash and trust funds	(11,375)	(25,916)	—	—	(37,291)
Net Cash Provided by Investing Activities	32,361	211,506	55,247	(297,556)	1,558
Cash Flows from Financing Activities					
Proceeds from issuance of long-term debt, net	(335)	301,124	(33,933)	223,775	490,631
Capital contribution from parent to subsidiary	92,000	—	(92,000)	—	—
Deferred debt issuance costs	—	53	(8,550)	—	(8,497)
Principal payments on short and long-term debt	—	(567,806)	—	—	(567,806)
Net Cash Provided (Used) by Financing Activities	91,665	(266,629)	(134,483)	223,775	(85,672)
Change in Cash from Discontinued Operations	—	10,822	—	—	10,822
Effect of Exchange Rate Changes on Cash and Cash Equivalents	54	25,534	—	—	25,588
Net Increase (Decrease) in Cash and Cash Equivalents	(28,104)	41,753	256,004	—	269,653
Cash and Cash Equivalents at Beginning of Period	295,509	160,434	95,280	—	551,223
Cash and Cash Equivalents at End of Period	$267,405	$ 202,187	$ 351,284	$ —	$ 820,876

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

NRG Energy, Inc. and Subsidiaries
Consolidating Statements of Operations
For the Six Months Ended June 30, 2003
Predecessor Company
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$ 639,588	$ 272,335	$ 25,598	$ (912)	$ 936,609
Operating Costs and Expenses					
Cost of majority-owned operations	555,459	187,938	16,947	(912)	759,432
Depreciation and amortization	74,320	40,831	7,755	—	122,906
General, administrative and development	26,456	24,908	36,299	—	87,663
Reorganization items	1,452	—	4,882	—	6,334
Restructuring and impairment charges	227,437	(136,007)	200,337	—	291,767
Total operating costs and expenses	885,124	117,670	266,220	(912)	1,268,102
Operating Income/(Loss)	(245,536)	154,665	(240,622)	—	(331,493)
Other Income (Expense)					
Equity in earnings of consolidated subsidiaries	104,375	1,476	(135,648)	29,797	—
Equity in earnings/(losses) of unconsolidated affiliates	66,437	26,527	(478)	—	92,486
Write downs and losses on sales of equity method investments	(12,257)	(136,770)	—	—	(149,027)
Other income, net	3,092	6,311	(4,019)	(1,842)	3,542
Interest expense	(70,848)	(80,164)	(111,591)	1,842	(260,761)
Total other income (expense)	90,799	(182,620)	(251,736)	29,797	(313,760)
Loss From Continuing Operations Before Income Taxes	(154,737)	(27,955)	(492,358)	29,797	(645,253)
Income Tax Expense (Benefit)	(78,855)	3,183	113,014	—	37,342
Loss From Continuing Operations	(75,882)	(31,138)	(605,372)	29,797	(682,595)
Income (Loss) on Discontinued Operations, net of Income Taxes	(22,881)	100,104	(15,661)	—	61,562
Net Income/(Loss)	$ (98,763)	$ 68,966	$ (621,033)	$ 29,797	$ (621,033)

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

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NRG Energy, Inc. and Subsidiaries
Consolidating Statements of Operations
For the Three Months Ended June 30, 2003
Predecessor Company
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$ 297,161	$ 131,345	$ 13,663	$ (570)	$ 441,599
Operating Costs and Expenses					
Cost of majority-owned operations	286,838	86,403	9,174	(570)	381,845
Depreciation and amortization	38,420	20,951	4,397	—	63,768
General, administrative and development	10,301	15,290	13,556	—	39,147
Reorganization items	1,452	—	4,882	—	6,334
Restructuring and impairment charges	225,295	(107)	44,443	—	269,631
Total operating costs and expenses	562,306	122,537	76,452	(570)	760,725
Operating Income/(Loss)	(265,145)	8,808	(62,789)	—	(319,126)
Other Income (Expense)					
Equity in earnings of consolidated subsidiaries	(121,396)	1,476	(408,376)	528,296	—
Equity in earnings/(losses) of unconsolidated affiliates	38,647	8,705	(495)	—	46,857
Write downs and gains/(losses) on sales of equity method investments	2,196	(134,632)	—	—	(132,436)
Other income, net	1,416	4,003	(11,530)	(1,842)	(7,953)
Interest expense	(35,066)	(42,468)	(16,395)	1,842	(92,087)
Total other income (expense)	(114,203)	(162,916)	(436,796)	528,296	(185,619)
Loss From Continuing Operations Before Income Taxes	(379,348)	(154,108)	(499,585)	528,296	(504,745)
Income Tax Expense (Benefit)	(95,557)	(2,447)	102,309	—	4,305
Loss From Continuing Operations	(283,791)	(151,661)	(601,894)	528,296	(509,050)
Income (Loss) on Discontinued Operations, net of Income Taxes	3,056	(95,900)	(6,507)	—	(99,351)
Net Loss	$ (280,735)	$ (247,561)	$ (608,401)	$ 528,296	$ (608,401)

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

NRG Energy, Inc. and Subsidiaries
Consolidating Balance Sheets
at December 31, 2003
Reorganized NRG

	Guarantor Subsidiaries	Non- Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ 295,509	$ 160,434	$ 95,280	$ —	$ 551,223
Restricted cash	4,298	111,769	—	—	116,067
Accounts receivable-trade, net	120,411	68,151	13,359	—	201,921
Xcel Energy settlement receivable	—	—	640,000	—	640,000
Current portion of notes receivable — affiliates	—	—	31,170	(30,970)	200
Current portion of notes receivable	—	64,854	287	—	65,141
Inventory	164,853	28,839	1,234	—	194,926
Derivative instruments valuation	772	—	—	—	772
Prepayments and other current assets	86,671	58,200	78,263	(956)	222,178
Current deferred income taxes	—	2,998	—	(1,148)	1,850
Current assets — discontinued operations	—	119,561	—	—	119,561
Total current assets	672,514	614,806	859,593	(33,074)	2,113,839
Property, Plant and Equipment					
In service	2,288,280	1,562,048	35,137	—	3,885,465
Under construction	20,600	118,433	138	—	139,171
Total property, plant and equipment	2,308,880	1,680,481	35,275	—	4,024,636
Less accumulated depreciation	(7,118)	(3,923)	(759)	—	(11,800)
Net property, plant and equipment	2,301,762	1,676,558	34,516	—	4,012,836
Other Assets					
Investment in subsidiaries	626,979	—	4,090,996	(4,717,975)	—
Equity investments in affiliates	403,606	322,279	12,113	—	737,998
Notes receivable, less current portion — affiliates	389,257	120,733	—	(379,838)	130,152
Notes receivable, less current portion	5,678	684,489	1,277	—	691,444
Intangible assets, net	411,540	20,821	—	—	432,361
Debt issuance costs, net	—	—	74,337	—	74,337
Derivative instruments valuation	—	59,907	—	—	59,907
Non-current deferred income tax	58,586	—	—	(58,586)	—
Funded letter of credit	—	—	250,000	—	250,000
Other assets	36,029	30,612	56,504	—	123,145
Non-current assets — discontinued operations	—	618,968	—	—	618,968
Total other assets	1,931,675	1,857,809	4,485,227	(5,156,399)	3,118,312
Total Assets	$4,905,951	$ 4,149,173	$ 5,379,336	$(5,189,473)	$ 9,244,987

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

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NRG Energy, Inc. and Subsidiaries
Consolidating Balance Sheets — (Continued)
at December 31, 2003
Reorganized NRG

	Guarantor Subsidiaries	Non- Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Current portion of long-term debt and capital leases	$ 30,121	$ 790,078	$ 12,000	$ (30,970)	$ 801,229
Short-term debt	—	19,019	—	—	19,019
Accounts payable — trade	39,378	104,916	14,389	—	158,683
Accounts payable — affiliates	333,722	(217,207)	(102,094)	(7,368)	7,053
Accrued taxes	—	—	(74)	16,169	16,095
Accrued property, sales and other taxes	7,232	13,156	1,934	—	22,322
Accrued salaries, benefits and related costs	9,295	8,949	1,087	—	19,331
Accrued interest	2,557	2,880	4,501	(956)	8,982
Derivative instruments valuation	429	—	—	—	429
Creditor pool obligation	—	—	540,000	—	540,000
Other bankruptcy settlement	—	220,000	—	—	220,000
Current deferred income tax	509	—	—	(509)	—
Other current liabilities	70,251	13,639	18,971	—	102,861
Current liabilities — discontinued operations	—	110,177	—	—	110,177
Total current liabilities	493,494	1,065,607	490,714	(23,634)	2,026,181
Other Liabilities					
Long-term debt and capital leases	10,999	1,333,931	2,446,690	(463,838)	3,327,782
Deferred income taxes	—	152,392	(22,514)	19,615	149,493
Postretirement and other benefit obligations	80,720	13,425	11,801	—	105,946
Derivative instruments valuation	—	153,503	—	—	153,503
Other long-term obligations	399,353	66,196	15,389	—	480,938
Non-current liabilities — discontinued operations	—	558,884	—	—	558,884
Total non-current liabilities	491,072	2,278,331	2,451,366	(444,223)	4,776,546
Total Liabilities	984,566	3,343,938	2,942,080	(467,857)	6,802,727
Minority Interest	—	5,004	—	—	5,004
Commitments and Contingencies					
Stockholders' Equity	3,921,385	800,231	2,437,256	(4,721,616)	2,437,256
Total Liabilities and Stockholders' Equity	$4,905,951	$ 4,149,173	$ 5,379,336	$(5,189,473)	$ 9,244,987

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

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NRG Energy, Inc. and Subsidiaries
Consolidating Statements of Cash Flows
For the Six Months Ended June 30, 2003
Predecessor Company
(Unaudited)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income/(loss)	$ (98,763)	$ 68,966	$ (621,033)	$ 29,797	$ (621,033)
Adjustments to reconcile net income/(loss) to net cash provided (used) by operating activities					
Distributions in excess of (less than) equity in earnings of unconsolidated affiliates	(108,670)	(21,602)	136,126	(29,797)	(23,943)
Depreciation and amortization	75,020	62,446	7,755	—	145,221
Amortization of debt issuance costs	2,095	5,047	3,948	—	11,090
Deferred income taxes	(132,854)	3,966	134,322	31,091	36,525
Non-cash contribution from members-current taxes	24,558	(38,008)		13,450	—
Minority interest	—	466	—	—	466
Unrealized (gains)/losses on derivatives	(29,524)	(5,576)	52,896	—	17,796
Asset impairment	245,437	101,344	1,132	—	347,913
Write downs and losses on sales of equity method investments	11,313	134,951	2,577	—	148,841
(Gain)/loss on sale of discontinued operations	2,224	(245,633)	24,873	—	(218,536)
Cash provided (used) by changes in certain working capital items, net of acquisition affects					
Accounts receivable	35,646	16,806	(96,060)	—	(43,608)
Accrued taxes	—	—	25,938	(44,541)	(18,603)
Inventory	14,413	(3,474)	2,611	—	13,550
Prepayments and other current assets	(77,604)	17,599	(14,257)	—	(74,262)
Accounts payable	102,070	(12,954)	174,990	—	264,106
Accounts payable — affiliates	99,780	(157,343)	62,351	—	4,788
Accrued property, sales and other taxes	2,126	3,264	8	—	5,398
Accrued salaries, benefits and related costs	5,963	(2,953)	(6,779)	—	(3,769)
Accrued interest	(35,309)	43,244	118,643	—	126,578
Other current liabilities	5,596	16,782	(139,733)	—	(117,355)
Cash (provided)/used by changes in other assets and liabilities	(16,881)	11,884	27,866	—	22,869
Net Cash Provided (Used) by Operating Activities	126,636	(778)	(101,826)	—	24,032
Cash Flows from Investing Activities					
Proceeds on sale of equity method investments	—	89,223	—	—	89,223

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations (1)	Consolidated Balance
			(In thousands)		
Investment in subsidiaries	—	—	135,252	(135,252)	—
Investments in equity method investments and projects	(250)	(119)	—	—	(369)
Decrease in note receivable, net	78,855	7,784	6	(77,240)	9,405
Capital expenditures	(10,953)	(45,041)	(611)	—	(56,605)
Increase in restricted cash and trust funds	(4,366)	(9,771)	—	—	(14,137)
Net Cash Provided by Investing Activities	63,286	42,076	134,647	(212,492)	27,517
Cash Flows from Financing Activities					
Proceeds from issuance of long-term debt, net	—	5,342	—	—	5,342
Deferred debt issuance costs	(7,428)	(46)	—	—	(7,474)
Capital contributions from parent	(135,252)	—	—	135,252	—
Principal payments on short and long-term debt	(3,106)	(105,524)	—	77,240	(31,390)
Net Cash Used by Financing Activities	(145,786)	(100,228)	—	212,492	(33,522)
Change in Cash from Discontinued Operations	—	24,062	—	—	24,062
Effect of Exchange Rate Changes on Cash and Cash Equivalents	2,287	(95,450)	—	—	(93,163)
Net Increase (Decrease) in Cash and Cash Equivalents	46,423	(130,318)	32,821	—	(51,074)
Cash and Cash Equivalents at Beginning of Period	63,403	228,135	69,322	—	360,860
Cash and Cash Equivalents at End of Period	$ 109,826	$ 97,817	$ 102,143	$ —	$ 309,786

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

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Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

3.2	Amended and Restated By-laws.(2)
14	Code of Conduct. (2)
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. (1)
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. (1)
31.3	Certification of Controller pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. (1)
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. (1)
99.1	Financial Statements of Louisiana Generating LLC for the six months ended June 30, 2004.(1)
99.2	Financial Statements of NRG Northeast Generating LLC for the six months ended June 30, 2004.(1)
99.3	Financial Statements of Indian River Power LLC for the six months ended June 30, 2004.(1)
99.4	Financial Statements of NRG MidAtlantic Generating LLC for the six months ended June 30, 2004.(1)
99.5	Financial Statements of NRG South Central Generating LLC for the six months ended June 30, 2004.(1)
99.6	Financial Statements of NRG Eastern LLC for the six months ended June 30, 2004.(1)
99.7	Financial Statements of Northeast Generation Holding LLC for the six months ended June 30, 2004.(1)
99.8	Financial Statements of NRG International LLC for the six months ended June 30, 2004.(1)

(1) Filed herewith.

(2) Incorporated herein by reference to NRG Energy, Inc.'s Form 10-Q for the quarter ended June 30, 2004, filed on August 9, 2004.

(b) Reports on Form 8-K:

NRG Energy filed or furnished reports on Form 8-K on the following dates during the quarter ended June 30, 2004:

Form 8-K, filed on May 3, 2004, to provide information under Item 7 regarding an amendment to the credit agreement dated as of December 23, 2003.

Form 8-K, filed on May 3, 2004, to provide information under Item 4 that PricewaterhouseCoopers LLP would decline to stand for re-election as the company's independent auditors.

Form 8-K, filed on May 3, 2004, to provide information under Item 5 that we initiated a search for a new independent auditor.

Form 8-K, filed on May 7, 2004, to provide under Item 5 notice of our entering into an agreement to sell our interest in a generating plant located in Batesville, Mississippi.

Form 8-K, furnished on May 11, 2004, to provide information under Item 12 regarding our financial and operating results for the quarter ended March 31, 2004.

Form 8-K, filed on May 25, 2004, to provide information under Item 4 announcing that the Audit Committee engaged KPMG LLP as our independent registered public accounting firm.

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

Date: November 2, 2004

EXHIBIT INDEX

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(1) Filed herewith.
(2) Incorporated herein by reference to NRG Energy, Inc.'s Form 10-Q for the quarter ended June 30, 2004, filed on August 9, 2004.

EXHIBIT 31.1

CERTIFICATION

I, David Crane, certify that:

1. I have reviewed this quarterly report on Form 10-Q/A 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)) 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) Omitted pursuant to SEC Release 33-8238;

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

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

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

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

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

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

Date: November 2, 2004

EXHIBIT 31.2

CERTIFICATION

I, Robert Flexon, certify that:

1. I have reviewed this quarterly report on Form 10-Q/A 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)) 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) Omitted pursuant to SEC Release 33-8238;

(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 FLEXON

Robert Flexon
Chief Financial Officer
(Principal Financial Officer)

Date: November 2, 2004

EXHIBIT 31.3

CERTIFICATION

I, James Ingoldsby, certify that:

1. I have reviewed this quarterly report on Form 10-Q/A 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)) 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) Omitted pursuant to SEC Release 33-8238;

(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 INGOLDSBY
James Ingoldsby
Vice President and Controller
(Principal Accounting Officer)

Date: November 2, 2004

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/A for the quarter ended June 30, 2004, as filed with the Securities and Exchange Commission on the date hereof (Form 10-Q/A), 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/A 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/A 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/A.

Date: November 2, 2004

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

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

/s/ JAMES INGOLDSBY
James Ingoldsby,
Vice President and 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.

EXHIBIT 99.1

LOUISIANA GENERATING LLC

FINANCIAL STATEMENTS

At June 30, 2004 and December 31, 2003, and for

the Three and Six Months Ended June 30, 2004 and 2003

LOUISIANA GENERATING LLC

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LOUISIANA GENERATING LLC

BALANCE SHEETS

(Unaudited)

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 50,685	$ 4,612
Restricted cash	—	99
Accounts receivable	33,333	37,039
Accounts receivable — affiliates	—	3,812
Note receivable	—	584
Inventory	28,732	34,077
Prepayments and other current assets	4,313	6,588
Total current assets	117,063	86,811
Property, plant and equipment, net of accumulated depreciation of $32,484, and $2,452, respectively	858,329	863,096
Intangible assets, net of accumulated amortization of $7,314 and $787, respectively	99,880	120,854
Decommissioning fund investments	4,916	4,809
Other assets	877	685
Total assets	$1,081,065	$1,076,255
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Accounts payable	$ 4,862	$ 10,430
Accounts payable — affiliates	8,894	—
Other current liabilities	15,194	18,433
Total current liabilities	28,950	28,863
Burdensome contracts	370,187	387,524
Other long-term obligations	10,377	9,789
Total liabilities	409,514	426,176
Commitments and contingencies		
Member's equity	671,551	650,079
Total liabilities and member's equity	$1,081,065	$1,076,255

The accompanying notes are an integral part of these financial statements.

LOUISIANA GENERATING LLC

STATEMENTS OF OPERATIONS

(Unaudited)

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)			
Revenues	**$ 106,424**	$ 92,098	**$ 204,845**	$ 195,969
Operating costs	**66,092**	62,880	**130,402**	130,157
Depreciation and amortization	**13,883**	8,647	**30,032**	16,221
General and administrative expenses	**5,308**	2,473	**9,229**	4,744
Reorganization items	**(71)**	—	**598**	—
Income from operations	**21,212**	18,098	**34,584**	44,847
Other income, net	**15**	314	**37**	641
Interest (expense) benefit	**1,298**	(17,370)	**1,298**	(34,843)
Income before income taxes	**22,525**	1,042	**35,919**	10,645
Income tax expense	**9,059**	418	**14,447**	4,357
Net income	**$ 13,466**	$ 624	**$ 21,472**	$ 6,288

The accompanying notes are an integral part of these financial statements.

LOUISIANA GENERATING LLC

STATEMENTS OF MEMBER'S EQUITY

For the Three Months Ended June 30, 2004 and 2003
(Unaudited)

	Member Units	Member Amount	Member Contributions/ Distributions	Accumulated Net Income	Total Member's Equity
			(In thousands of dollars)		
Balances at March 31, 2003 (Predecessor Company)	1,000	$ 1	$ 239,870	$ 36,505	$276,376
Net income	—	—	—	624	624
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 239,870	$ 37,129	$277,000
Balances at March 31, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 649,622**	**$ 8,462**	**$658,085**
Net income	**—**	**—**	**—**	**13,466**	**13,466**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 649,622**	**$ 21,928**	**$671,551**

The accompanying notes are an integral part of these financial statements.

LOUISIANA GENERATING LLC

STATEMENTS OF MEMBER'S EQUITY

For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Member		Member Contributions/	Accumulated	Total Member's
	Units	Amount	Distributions	Net Income	Equity
	(In thousands of dollars)				
Balances at December 31, 2002 (Predecessor Company)	1,000	$ 1	$ 239,870	$ 30,841	$270,712
Net income	—	—	—	6,288	6,288
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 239,870	$ 37,129	$277,000
Balances at December 31, 2003 (Reorganized Company)	**1,000**	**$ 1**	**$ 649,622**	**$ 456**	**$650,079**
Net income	**—**	**—**	**—**	**21,472**	**21,472**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 649,622**	**$ 21,928**	**$671,551**

The accompanying notes are an integral part of these financial statements.

LOUISIANA GENERATING LLC

STATEMENTS OF CASH FLOWS

(Unaudited)

	Reorganized Company	Predecessor Company
	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)	
Cash flows from operating activities		
Net income	**$ 21,472**	$ 6,288
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**30,032**	16,221
Deferred income taxes	**14,447**	4,357
Amortization of intangibles	**6,527**	214
Amortization of out-of-market power contracts	**(17,337)**	—
Changes in assets and liabilities		
Accounts receivable	**3,706**	15,372
Inventory	**5,345**	4,269
Prepayments and other current assets	**2,275**	(4,133)
Accounts payable	**(5,568)**	12,317
Accounts payable and receivable — affiliates, net	**12,706**	5,672
Accrued interest — affiliates	**—**	(35,337)
Accrued fuel and purchased power expense	**—**	(7,491)
Other current liabilities	**(3,239)**	(3,715)
Changes in other assets and liabilities	**289**	(216)
Net cash provided by operating activities	**70,655**	13,818
Cash flows from investing activities		
Capital expenditures	**(25,265)**	(5,389)
Decrease in note receivable	**584**	1,500
(Increase)/decrease in restricted cash	**99**	(1,917)
Net cash used in investing activities	**(24,582)**	(5,806)
Cash flows from financing activities		
Net cash provided by financing activities	**—**	—
Net increase in cash and cash equivalents	**46,073**	8,012
Cash and cash equivalents		
Beginning of period	**4,612**	—
End of period	**$ 50,685**	$ 8,012

The accompanying notes are an integral part of these financial statements.

LOUISIANA GENERATING LLC

NOTES TO FINANCIAL STATEMENTS

(Unaudited)

1. Organization

Louisiana Generating LLC ("Louisiana Generating" or the "Company") is an indirect wholly owned subsidiary of NRG Energy, Inc. ("NRG Energy"). NRG South Central ("South Central") owns 100% of the Company. South Central's members are NRG Central U.S. LLC ("NRG Central") and South Central Generation Holding LLC ("South Central Generation"). NRG Central and South Central Generation are directly held wholly owned subsidiaries of NRG Energy, each of which owns a 50% interest in South Central.

The Company was formed for the purpose of acquiring, owning, operating and maintaining the electric generating facilities acquired from Cajun Electric Power Cooperative, Inc. ("Cajun Electric"). Pursuant to a competitive bidding process, following the Chapter 11 bankruptcy proceeding of Cajun Electric, Louisiana Generating acquired the non-nuclear electric power generating assets of Cajun Electric.

Recent Developments

On May 14, 2003, NRG Energy and 25 of its direct and indirect wholly owned subsidiaries commenced voluntary petitions under Chapter 11 of the bankruptcy code in the United States Bankruptcy Court for the Southern District of New York. The Company was included in the Chapter 11 filing. During the bankruptcy proceedings, NRG Energy continued to conduct business and manage the companies as debtors in possession pursuant to sections 1107(a) and 1108 of the bankruptcy code. Two plans of reorganization were filed in connection with the restructuring efforts. The first, filed on May 14, 2003, and referred to as NRG Energy's Plan of Reorganization, relates to NRG Energy and the other NRG Energy plan debtors. The second plan, relating to the Company, the Northeast Generating subsidiaries and the other South Central subsidiaries, referred to as the Northeast/ South Central Plan of Reorganization, was filed on September 17, 2003. On November 24, 2003, the bankruptcy court entered an order confirming NRG Energy's Plan of Reorganization and the plan became effective on December 5, 2003. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/ South Central Plan of Reorganization and the plan became effective on December 23, 2003. In connection with NRG Energy's emergence from bankruptcy, NRG Energy adopted fresh start accounting in accordance with AICPA Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code* ("SOP 90-7") on December 5, 2003. NRG Energy's fresh start accounting was applied to the Company on a push down accounting basis with the financial statement impact recorded as an adjustment to the December 6, 2003 member's equity.

Northeast/ South Central Plan of Reorganization

The Northeast/ South Central Plan of Reorganization was proposed on September 17, 2003 after necessary financing commitments were secured. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/ South Central Plan of Reorganization and the plan became effective on December 23, 2003. In connection with the order confirming the Northeast/ South Central Plan of Reorganization, the court entered a separate order which provides that the allowed amount of the bondholders' claims shall equal in the aggregate the sum of (i) $1.3 billion plus (ii) any accrued and unpaid interest at the applicable contract rates through the date of payment to the indenture trustee plus (iii) the reasonable fees, costs or expenses of the collateral agent and indenture trustee (other than reasonable professional fees incurred from October 1, 2003) plus (iv) $19.6 million, ratably, for each holder of bonds based upon the current outstanding principal amount of the bonds and irrespective of (a) the date of maturity of the bonds, (b) the interest rate applicable to such bonds and (c) the issuer of the bonds.

The creditors of Northeast and South Central subsidiaries were unimpaired by the Northeast/ South Central Plan of Reorganization. The creditors holding allowed general secured claims were paid in cash, in full on the effective date of the Northeast/ South Central Plan of Reorganization. Holders of allowed unsecured claims received either (i) cash equal to the unpaid portion of their allowed unsecured claim, (ii) treatment that leaves unaltered the legal, equitable and contractual rights to which such unsecured claim entitles the holder of such claim, (iii) treatment that otherwise renders such unsecured claim unimpaired pursuant to section 1124 of the bankruptcy code or (iv) such other, less favorable treatment that is confirmed in writing as being acceptable to such holder and to the applicable debtor.

2. Summary of Significant Accounting Policies

Basis of Presentation

As used in these unaudited interim financial statements, "Predecessor Company" refers to the Company prior to NRG Energy's emergence from bankruptcy. "Reorganized Company" refers to the Company after NRG Energy's emergence from bankruptcy.

The accompanying unaudited interim financial statements have been prepared in accordance with the Securities and Exchange Commission's or "SEC" regulations for interim financial information. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. The accounting policies followed are set forth in Note 2 to the Company's annual audited financial statements for the year ended December 31, 2003. The following notes should be read in conjunction with such policies and other disclosures. Interim results are not necessarily indicative of results for a full year.

In the opinion of management, the accompanying unaudited interim financial statements contain all material adjustments necessary to present fairly the Company's financial position as of June 30, 2004 and December 31, 2003, the results of its operations and member's equity for the three and six months ended June 30, 2004 and 2003 and the cash flows for the six months ended June 30, 2004 and 2003. Certain prior-year amounts have been reclassified for comparative purposes.

Comparability of Financial Information

Due to NRG Energy's adoption of Fresh Start as of December 5, 2003, the Reorganized Company's balance sheet, statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are not comparable in certain respects to the financial statements prior to the application of push down accounting from NRG Energy's fresh start accounting. A black line has been drawn on the accompanying financial statements (excluding the balance sheet) to separate and distinguish between the Reorganized Company and the Predecessor Company.

3. Other Charges

For the six months ended June 30, 2004, the Company incurred $0.6 million of reorganization costs. All reorganization costs have been incurred since the Company filed for bankruptcy in May 2003. These costs consist of bankruptcy related charges primarily related to professional fees and liability settlements. For the three months ended June 30, 2004, a net credit of $71,000 was recorded related to the settlement of obligations recorded under Fresh Start accounting. No reorganization costs were recorded for the three and six months ended June 30, 2003.

The Company reviewed the recoverability of its long-lived assets in accordance with the guidelines of Statement of Financial Accounting Standards ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* As a result of this review, no impairment charges were recorded for the three and six months ended June 30, 2004 and 2003.

4. Inventory

Inventory, which is valued at the lower of weighted average cost or market, consists of:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Coal	$20,915	$ 26,108
Spare parts	7,020	7,186
Fuel oil	797	783
Total inventory	$28,732	$ 34,077

5. Property, Plant and Equipment

The major classes of property, plant and equipment were as follows:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Land	$ 20,142	$ 20,142
Facilities, machinery and equipment	845,077	845,077
Construction in progress	25,594	329
Accumulated depreciation	(32,484)	(2,452)
Property, plant and equipment, net	$858,329	$ 863,096

6. Asset Retirement Obligation

Effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (“SFAS No. 143”). SFAS No. 143 requires an entity to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The Company identified certain retirement obligations within its operations. These asset retirement obligations are related primarily to the future dismantlement of equipment on leased property and environment obligations related to ash disposal site closures. The Company also identified similar other asset retirement obligations that could not be calculated because the assets associated with the retirement obligations were determined to have an indeterminate life. The adoption of SFAS No. 143 resulted in recording a $0.2 million increase to property, plant and equipment and a $0.3 million increase to other long-term obligations. The cumulative effect of adopting SFAS No. 143 was recorded as a $21,000 increase to depreciation expense and a $0.1 million increase to operating costs as the Company considered the cumulative effect to be immaterial.

The following represents the balances of the asset retirement obligation as of January 1, 2004, and the accretion of the asset retirement obligation for the six months ended June 30, 2004, which is included in other long-term obligations in the balance sheet.

	Reorganized Company		
	Beginning Balance January 1, 2004	Accretion for the Six Months Ended June 30, 2004	Ending Balance June 30, 2004
	(In thousands of dollars)		
Asset retirement obligations	$ 2,063	$ 71	$2,134

7. Intangible Assets

Upon the application of push down accounting, the Company established certain intangible assets for power sales agreements and plant emission allowances. These intangible assets will be amortized over their respective lives based on a straight-line or units of production basis to resemble the Company's realization of such assets.

Power sale agreements will be amortized as a reduction to revenue over the terms and conditions of each contract. The remaining amortization period is three years for the power sale agreements. Emission allowances will be amortized as additional fuel expense based upon the actual level of emissions from the respective plants through 2023. Aggregate amortization recognized for the three and six months ended June 30, 2004, was approximately $3.2 million and $6.5 million, respectively. The annual aggregate amortization for each of the five succeeding years is expected to approximate $11.5 million in years one through three and $5 million in years four and five for both the power sale agreements and emission allowances. The expected annual amortization of these amounts is expected to change as the Company relieves the tax valuation allowance, as explained below.

For the three and six months ended June 30, 2004, the Company reduced its tax valuation allowance by $9.1 million and $14.5 million, respectively, and in accordance with SOP 90-7, recorded a corresponding reduction related to the Company's intangible assets. As a result of the recognition of a deferred tax asset valuation allowance in connection with push down accounting, any future benefits from reducing the valuation allowance should first reduce intangible assets until exhausted, and thereafter be recorded as a direct addition to paid in capital.

Intangible assets consisted of the following:

	Power Sale Agreements	Emission Allowances	Total
	(In thousands of dollars)		
Balances as of December 31, 2003	$ 27,013	$ 93,841	$120,854
Tax valuation adjustment	(3,229)	(11,218)	(14,447)
Amortization	(3,636)	(2,891)	(6,527)
Balances as of June 30, 2004	$ 20,148	$ 79,732	$ 99,880

8. Derivative Instruments and Hedging Activity

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"), as amended, requires the Company to record all derivatives on the balance sheet as assets or liabilities at fair value. For derivatives designated as cash flow hedges, the effective portion of the changes in fair value of the derivatives are recorded in accumulated other comprehensive income ("OCI") and subsequently recognized in earnings when the hedged items impact 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. Changes in the fair value of nonhedge derivatives will be immediately recognized in earnings.

SFAS No. 133 applies to South Central's long-term power sales contracts, long-term fuel purchase contracts and other energy related commodities financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect investment in fuel inventories. The Company has long-term power sales contracts and fuel purchase agreements that qualify as normal purchase and sales under SFAS No. 133, and are therefor exempt from fair value accounting treatment. All other derivative activities are conducted by an affiliate of South Central and are not recorded by the Company.

9. Commitments and Contingencies

Contractual Commitments

Power Supply Agreements with the Distribution Cooperatives

During March 2000, the Company entered into certain power supply agreements with eleven distribution cooperatives to provide energy, capacity and transmission services. The agreements are standardized into three types, Form A, B and C. In connection with the application of push down accounting, certain of the Company's long-term power supply agreements were determined to be at above or below market rates. As a result, the Company valued these agreements and recognized the fair value of such contracts on the December 6, 2003 balance sheet. The fair value of these contracts that were deemed to be valuable have been included in intangible assets. The fair value of contracts determined to be significantly burdensome were recorded as noncurrent liabilities. The favorable and unfavorable contract valuation amounts will be amortized as a net increase to revenues over the terms and conditions of each contract. These contracts consist primarily of the long-term power sale agreements the Company has with its cooperative customers and certain others. The gross carrying amount of the unfavorable out-of-market power sales agreements at both June 30, 2004 and December 31, 2003, was $390.5 million. During the three and six months ended June 30, 2004, approximately $6.7 million and $13.7 million, respectively, was amortized as an increase to revenues.

Form A Agreements

Six of the distribution cooperatives entered into Form A power supply agreements. The Form A agreement is an all-requirements power supply agreement which has an initial term of 25 years, commencing on March 31, 2000. After the initial term, the agreement continues on a year-to-year basis, unless terminated by either party giving five years advanced notice.

Under the Form A power supply agreement, the Company is obligated to supply the distribution cooperative all of the energy and capacity required by the distribution cooperative for service to its retail customers although the distribution cooperative has certain limited rights under which it can purchase energy and capacity from third parties.

The Company must contract for all transmission service required to serve the distribution cooperative and will pass through the costs of transmission service to the cooperative. The Company is required to supply at its cost, without pass through, control area services and ancillary services which transmission providers are not required to provide.

The Company owns and maintains the substations and other facilities used to deliver energy and capacity to the distribution cooperative and charges the cooperative a monthly specific delivery facility charge for such facilities any additions to, or new delivery facilities. The initial monthly charge is 1% of the value of all of the distribution cooperative's specific delivery facilities. The cost of additional investment during the term of the agreement will be added to the initial value of the delivery facilities to calculate the monthly specific delivery facility charge.

The Company charges the distribution cooperative a demand charge, a fuel charge and a variable operation and maintenance charge. The demand charge consists of two components, a capital rate and a fixed operation and maintenance rate. The distribution cooperatives have an option to choose one of two fuel options, all six have selected the first option which is a fixed fee through 2004 and determined using a formula which is based on gas prices and the cost of delivered coal for the period thereafter. At the end of the fifteenth year of the contract, the cooperatives may switch to the second fuel option. The second fuel option consists of a pass-through of fuel costs, with a guaranteed coal heat rate and purchased energy costs, excluding the demand component in purchased power. From time to time, the Company may offer fixed fuel rates which the cooperative may elect to utilize. The variable operation and maintenance charge is fixed through 2004 and escalates at either approximately 3% per annum or in accordance with actual changes in specified indices as selected by the distribution cooperative. Five of the distribution cooperatives elected the fixed escalation provision and one elected the specified indices provision.

Form B Agreements

One distribution cooperative selected the Form B Power Supply Agreement. The term of the Form B power supply agreement commences on March 31, 2000 and ends on December 31, 2024. The Form B power supply agreement allows the distribution cooperative the right to elect to limit its purchase obligations to “base supply” or also to purchase “supplemental supply.” Base supply is the distribution cooperative’s ratable share of the generating capacity purchased by the Company from Cajun Electric. Supplemental supply is the cooperative’s requirements in excess of the base supply amount. The distribution cooperative which selected the Form B agreement also elected to purchase supplemental supply.

The Company charges the distribution cooperative a monthly specific delivery facility charge of approximately 1.75% of the depreciated net book value of the specific delivery facilities, including additional investment. The distribution cooperative may assume the right to maintain the specific delivery facilities and reduce the charge to 1.25% of the depreciated net book value of the specific delivery facilities. The Company also charges the distribution cooperative its ratable share of 1.75% of the depreciated book value of common delivery facilities, which include communications, transmission and metering facilities owned by the Company to provide supervisory control and data acquisition, and automatic control for its customers.

For base supply, the Company charges the distribution cooperative a demand charge, an energy charge and a fuel charge. The demand charge for each contract year is set forth in the agreement and is subject to increase for environmental legislation or occupational safety and health laws enacted after the effective date of the agreement. The Company can increase the demand charge to the extent its cost of providing supplemental supply exceeds $400 per kilowatt (“kW”). The energy charge is fixed through 2004, and decreased slightly for the remainder of the contract term. The fuel charge is a pass-through of fuel and purchased energy costs. The distribution cooperative may elect to be charged based on a guaranteed coal-fired heat rate of 10,600 British Thermal Units per kilowatt hour (“Btu/kWh”), and it may also select fixed fuel factors as set forth in the agreement for each year through 2008. The one distribution cooperative which selected this form of agreement elected to utilize the fixed fuel factors. For the years after 2008, the Company will offer additional fixed fuel factors for five-year periods that may be elected. For the years after 2008, the distribution cooperative may also elect to have its charges computed under the pass-through provisions with or without the guaranteed coal-fired heat rate.

At the beginning of year six, the Company will establish a rate fund equal to the ratable share of $18 million. The amount of the fund will be approximately $720,000. This fund will be used to offset the energy costs of the Form B distribution cooperatives which elected the fuel pass-through provision of the fuel charge, to the extent the cost of power exceeds $0.04/kWh. Any funds remaining at the end of the term of the power supply agreement will be returned to the Company.

Form C Agreements

Four distribution cooperatives selected the Form C power supply agreement. The Form C power supply agreement is identical to the Form A power supply agreement, except for the following.

The term of the Form C power supply agreement was for four years following the closing date of the acquisition of the Cajun facilities. In October 2003, the Louisiana Public Service Commission approved contract extensions for all four Form C distribution cooperatives for terms of an additional five or ten years.

The Company will charge the distribution cooperative a demand rate, a variable operation and maintenance charge and a fuel charge. The Company will not offer the distribution cooperatives which select the Form C agreement any new incentive rates, but will continue to honor existing incentive rates. At the end of the term of the agreement, the distribution cooperative is obligated to purchase the specific delivery facilities for a purchase price equal to the depreciated book value.

Other Power Supply Agreements

The Company assumed Cajun Electric's rights and obligations under two consecutive long-term power supply agreements with South Western Electric Power Company ("SWEPCO"), one agreement with South Mississippi Electric Power Association ("SMEPA") and one agreement with Municipal Energy Agency of Mississippi ("MEAM").

The SWEPCO Operating Reserves and Off-Peak Power Sale Agreement terminates on December 31, 2007. The agreement requires the Company to supply 100 MW of off-peak energy during certain hours of the day to a maximum of 292,000 MWh per year and an additional 100 MW of operating reserve capacity and the associated energy within ten minutes of a phone request during certain hours to a maximum of 43,800 MWh of operating reserve energy per year. The obligation to purchase the 100 MW of off-peak energy is contingent on the Company's ability to deliver operating reserve capacity and energy associated with operating reserve capacity. At the Company's request, it will supply up to 100 MW of nonfirm, on peak capacity and associated energy.

The SWEPCO Operating Reserves Capacity and Energy Power Sale Agreement is effective January 1, 2008 through December 31, 2026. The agreement requires the Company to provide 50 MW of operating reserve capacity within ten minutes of a phone request. In addition, SWEPCO is granted the right to purchase up to 21,900 MWh/year of operating reserve energy.

The SMEPA Unit Power Sale Agreement is effective through May 31, 2009, unless terminated following certain regulatory changes, changes in fuel costs or destruction of the Cajun facilities. The agreement requires the Company to provide 75 MW of capacity and the associated energy from Big Cajun II, Unit 1 and an option for SMEPA to purchase additional capacity and associated energy if the Company determines that it is available, in 10 MW increments, up to a total of 200 MW. SMEPA is required to schedule a minimum of 25 MW plus 37% of any additional capacity that is purchased. The capacity charge was fixed through May 31, 2004, and increased for the period June 1, 2004 through May 31, 2009, including transmission costs to the delivery point and any escalation of expenses. The energy charge is 110% of the incremental fuel cost for Big Cajun II, Unit 1.

The MEAM Power Sale Agreement is effective through May 31, 2010, with an option for MEAM to extend through September 30, 2015, upon five years advance notice. The agreement requires the Company to provide 20 MW of firm capacity and associated energy with an option for MEAM to increase the capacity purchased to a total of 30 MW upon five years advance notice. The capacity charge is fixed. The operation and maintenance charge is a fixed amount which escalates at 3.5% per year. There is a transmission charge which varies depending upon the delivery point. The price for energy associated with the firm capacity is 110% of the incremental generating cost to the Company and is adjusted to include transmission losses to the delivery point.

Coal Supply Agreement

The Company has entered into a coal supply agreement with Triton Coal. The coal is primarily sourced from Triton Coal's Buckskin and North Rochelle mines located in the Powder River Basin, Wyoming. The coal supply agreement has an initial term ending March 31, 2005. The agreement establishes a base price per ton for coal supplied by Triton Coal. The base price is subject to adjustment for changes in the level of taxes or other government fees and charges, variations in the caloric value and sulfur content of the coal shipped, and changes in the price of SO(2) emission allowances. The base price is based on certain annual weighted average quality specifications, subject to suspension and rejection limits.

Coal Transportation Agreement

The Company entered into a coal transportation agreement with Burlington Northern and Santa Fe Railway and American Commercial Terminal. The term of the agreement is five years from March 31, 2000. This agreement provides for the transportation of all of the coal requirements of Big Cajun II from the mines in Wyoming to Big Cajun II.

Transmission and Interconnection Agreements

The Company assumed Cajun Electric's existing transmission agreements with Central Louisiana Electric Company, SWEPCO; and Entergy Services, Inc., acting as agent for Entergy Arkansas, Inc., Entergy Gulf States, Inc., Entergy Louisiana, Inc., Entergy Mississippi, Inc., and Entergy New Orleans, Inc. The Company also entered into two interconnection and operating agreements with Entergy Gulf States, Inc. on May 1, 2002. The Cajun facilities are connected to the transmission system of Entergy Gulf States, Inc. and power is delivered to the distribution cooperatives at various delivery points on the transmission systems of Entergy Gulf States, Inc., Entergy Louisiana, Inc., Central Louisiana Electric Company and SWEPCO. The Company also assumed from Cajun Electric 20 interchange and sales agreements with utilities and cooperatives, providing access to a 12 state area.

Environmental Matters

The construction and operation of power projects are subject to stringent environmental and safety protection and land use laws and regulation in the United States. These laws and regulations generally require lengthy and complex processes to obtain licenses, permits and approvals from federal, state and local agencies. If such laws and regulations become more stringent and the Company's facilities are not exempted from coverage, the Company could be required to make extensive modifications to further reduce potential environmental impacts. Also, the Company could be held responsible under environmental and safety laws for the cleanup of pollutant releases at its facilities or at off-site locations where it has sent wastes.

The Company and its subsidiaries strive to exceed the standards of compliance with applicable environmental and safety regulations. Nonetheless, the Company expects that future liability under or compliance with environmental and safety requirements could have a material effect on its operations or competitive position. It is not possible at this time to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of possible changes to environmental and safety regulations, regulatory interpretations or enforcement policies. In general, the effect of future laws or regulations is expected to require the addition of pollution control equipment or the imposition of restrictions on the Company's operations.

The Company establishes accruals where reasonable estimates of probable environmental and safety liabilities are possible. The Company adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates are adjusted to reflect new information.

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility, including an electric generating facility, may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products located at the facility, and may be held liable to a governmental entity or to third parties for property damage, personal injury and investigation and remediation costs incurred by the party in connection with any releases or threatened releases. These laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended by the Superfund Amendments and Reauthorization Act of 1986, impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and courts have interpreted liability under such laws to be strict (without fault) and joint and several. The cost of investigation, remediation or removal of any hazardous or toxic substances or petroleum products could be substantial. The Company has not been named as a potentially responsible party with respect to any off-site waste disposal matter.

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 (one of the instruments allowed by the Louisiana Department of Environmental Quality for providing financial assurance for expenses associated with closure and post-closure care of the ponds). The value of the trust fund is approximately $4.9 million at June 30, 2004, and the Company is making annual payments to the fund in the amount of about $116,000. See Note 12.

The Louisiana Department of Environmental Quality has promulgated State Implementation Plan revisions to bring the Baton Rouge ozone nonattainment area into compliance with National Ambient Air Quality Standards. The Company participated in development of the revisions, which require the reduction of NO(x) emissions at the gas-fired Big Cajun I Power Station and coal-fired Big Cajun II Power Station to 0.1 pounds NO(x) per million Btu heat input and 0.21 pounds NO(x) per million Btu heat input, respectively. This revision of the Louisiana air rules would appear to constitute a change-in-law covered by agreement between the Company and the electric cooperatives allowing the costs of added combustion controls to be passed through to the cooperatives. The capital cost of combustion controls required at the Big Cajun II Generating Station to meet the State’s NO(x) regulations will total about $10.0 million for Unit 1. Units 2 and 3 have already made such changes. The capital cost of combustion controls required at the Big Cajun I Generating Station to meet the State’s NO(x) regulations will total about $5 million to $10 million for the Unit 1 and 2 steam boilers.

Legal Issues

United States Environmental Protection Agency Request for Information under Section 114 of the Clean Air Act

On January 27, 2004, Louisiana Generating, LLC and Big Cajun II received a request for information under Section 114 of the Clean Air Act from the United States Environmental Protection Agency (“EPA”) seeking information primarily relating to physical changes made at Big Cajun II in 1994 and 1995 by the predecessor owner of that facility. Louisiana Generating, LLC and Big Cajun II have been responding to the EPA request in an appropriate manner. At the present time, the Company cannot predict the probable outcome in this matter.

Travis Ballou, et al. v. Ralph Mabey, et al., United States Court of Appeals for the Fifth Circuit, No. 03-30343; Kenneth W. Austin, et al. v. Ralph Mabey, et al., United States District Court for the Middle District of Louisiana, Civil Action No. 00-728-D-M1

Two lawsuits are pending in Federal Court involving 39 former employees of Cajun Electric Power Cooperative, Inc. who claim age/race/sex discrimination in failure to hire by the Company. One lawsuit was dismissed on summary judgment and has been appealed. In the remaining lawsuit, the Company is awaiting the District Court's ruling on the Company's motions for summary judgment.

In the Matter of Louisiana Generating, LLC, Adversary Proceeding No. 2002-1095 1-EQ on the Docket of the Louisiana Division of Administrative Law

During 2000, the Louisiana Department of Environmental Quality ("DEQ") issued a Part 70 Air Permit modification to the Company to construct and operate two 240 MW natural gas-fired turbines. The Part 70 Air Permit set emissions limits for the criteria air pollutants, including NOx, based on the application of Best Available Control Technology ("BACT"). The BACT limitation for NO(x) was based on the guarantees of the manufacturer, Siemens-Westinghouse. The Company sought an interim emissions limit to allow Siemens-Westinghouse time to install additional control equipment. To establish the interim limit, DEQ issued a Compliance Order and Notice of Potential Penalty, No. AE-CN-02-0022, on September 8, 2002, which is, in part, subject to the referenced administrative hearing. DEQ alleged that Louisiana Generating did not meet its NO(x) emissions limit on certain days, did not conduct all opacity monitoring and did not complete all record keeping and certification requirements. The Company intends to vigorously defend certain claims and any future penalty assessment, while also seeking an amendment of its limit for NO(x). An initial status conference was held with the Administrative Law Judge and quarterly reports are being submitted to that judge to describe progress, including settlement and amendment of the limit. In late February 2004, the Company timely submitted to the DEQ an amended BACT analysis and amended Prevention of Significant Deterioration and Title V permit application to amend the NO(x) limit. The DEQ is presently processing the permit application. In addition, the Company may assert breach of warranty claims against the manufacturer. With respect to the administrative action described above, at this time the Company is unable to predict the eventual outcome of this matter or the potential loss contingencies, if any, to which the Company may be subject.

10. Regulatory Issues

The Company's assets are located within the control area of Entergy Corporation ("Entergy"), a vertically integrated utility. The utility performs the scheduling, reserve and reliability functions that are administered by the ISOs in certain other regions of the United States and Canada. The Company operates a National Electric Reliability Council ("NERC") certified control area within the Entergy control area, which is comprised of the Company's generating assets and its co-op customer loads. Although the reliability functions performed are essentially the same, the primary differences between these markets lie principally in the physical delivery and price discovery mechanisms. In the South Central region, all power sales and purchases are consummated bilaterally between individual counter-parties, and physically delivered either within or across the physical control areas of the transmission owners from the source generator to the sink load. Transacting counter-parties are required to reserve and purchase transmission services from the intervening transmission owners at their FERC approved tariff rates. Included with these transmission services are the reserve and ancillary costs. Energy prices in the South Central region are determined and agreed to in bilateral negotiations between representatives of the transacting counter-parties, using market information gleaned by the individual marketing agents arranging the transactions.

In the South Central area, including Entergy's service territory, the present energy market is not a centralized market and does not have an independent system operator as is found in the Northeast markets.

The Company presently has long-term all requirements contracts with 11 Louisiana Distribution Cooperatives, and long-term contracts with the Municipal Energy Agency of Mississippi, South Mississippi Electric Power Association and Southwestern Electric Power Company. The Distribution Cooperatives serve approximately 300,000 to 350,000 retail customers.

On March 31, 2004, Entergy filed with FERC a proposal to have an independent person monitor the Entergy operation of the transmission system. FERC has not ruled on this request. Also, it is unclear at this time how these recent developments will impact the Company.

11. Jointly Owned Plant

On March 31, 2000, the Company acquired a 58% interest in the Big Cajun II, Unit 3 generation plant. Entergy Gulf States, Inc. owns the remaining 42%. Big Cajun II, Unit 3 is operated and maintained by the Company pursuant to a joint ownership participation and operating agreement. Under this agreement, the Company and Entergy Gulf States, Inc. are each entitled to their ownership percentage of the hourly net electrical output of Big Cajun II, Unit 3. All fixed costs are shared in proportion to the ownership interests. Fixed costs include the cost of operating common facilities. All variable costs are borne in proportion to the energy delivered to the owners. The Company’s statements of operations include its share of all fixed and variable costs of operating the unit.

12. Decommissioning Fund

The Company is required by the State of Louisiana Department of Environmental Quality to rehabilitate its Big Cajun II ash and wastewater impoundment areas upon removal from service of the Big Cajun II facilities. On July 1, 1989, a guarantor trust fund (the “Solid Waste Disposal Trust Fund”) was established to accumulate the estimated funds necessary for such purpose. The Company’s predecessor deposited $1.06 million in the Solid Waste Disposal Trust Fund in 1989, and funded $116,000 annually thereafter, based upon an estimated future rehabilitation cost (in 1989 dollars) of approximately $3.5 million and the remaining estimated useful life of the Big Cajun II facilities. Prior to January 1, 2003, cumulative contributions to the Solid Waste Disposal Trust Fund and earnings on the investments therein were accrued as a decommissioning liability. Effective January 1, 2003, the Company adopted SFAS No. 143 and accounts for its decommissioning liability. At June 30, 2004 and December 31, 2003, the carrying value of the trust fund investments and the related accrued decommissioning liability was approximately $4.9 million and $4.8 million, respectively. The trust fund investments are comprised of various debt securities of the United States and are carried at amortized cost, which approximates their fair value.

13. Guarantees

In November 2002, the FASB issued Interpretation No. (“FIN”) 45, *Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* The initial recognition and initial measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor’s fiscal year end. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. The interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. The interpretation also clarifies the requirements related to the recognition of a liability by a guarantor at the inception of the guarantee for the obligations the guarantor has undertaken in issuing the guarantee.

In connection with the application of push down accounting, all outstanding guarantees were considered new; accordingly, the Company applied the provisions of FIN 45 to all of those guarantees. Each guarantee was reviewed for the requirement to recognize a liability at inception.

The Company is a guarantor under the debt issued by the Company's ultimate parent, NRG Energy. NRG Energy issued $1.25 billion of 8% Second Priority Notes on December 23, 2003, due and payable on December 15, 2013. On January 28, 2004, NRG Energy also issued $475.0 million of Second Priority Notes, under the same terms and indenture as its December 23, 2003 offering.

NRG Energy's payment obligations under the notes and all related Parity Lien Obligations are guaranteed on an unconditional basis by each of NRG Energy's current and future restricted subsidiaries, of which the Company is one. The notes are jointly and severally guaranteed by each of the guarantors. The subsidiary guarantees of the notes are secured, on a second priority basis, equally and ratably with any future Parity Lien Debt, by security interest in all of the assets of the guarantors, except certain excluded assets, subject to liens securing parity lien debt and other permitted prior liens.

The Company's obligations pursuant to its guarantees of the performance, equity and indebtedness obligations were as follows:

	Guarantee/ Maximum Exposure	Nature of Guarantee	Expiration Date	Triggering Event
		(In thousands of dollars)		
NRG Energy Second Priority Notes due 2013	$1,753,000	Obligations under credit agreement	2013	Nonperformance

14. Income Taxes

The Company is included in the consolidated tax return filings as a wholly owned indirect subsidiary of NRG Energy. Reflected in the financial statements and notes below are separate company federal and state tax provisions as if the Company had prepared separate filings. An income tax provision has been established on the accompanying financial statements as of the earliest period presented in order to reflect income taxes as if the Company filed its own tax return. The Company's ultimate parent, NRG Energy, does not have a tax allocation agreement with its subsidiaries and prior to January 1, 2003, income taxes were not recorded or allocated to non tax paying entities or entities such as the Company which are treated as disregarded entities for tax purposes. Because the Company is not a party to a tax sharing agreement, current tax expense (benefit) is recorded as a capital contribution from (distribution to) the Company's parent. The cumulative effect of recording an income tax provision (benefit) and deferred taxes resulted in recording as of December 31, 2002, a net deferred tax liability of $37.8 million and a reduction to member's equity of $37.8 million.

Income taxes for the six months ended June 30, 2004 was a tax expense of $14.4 million compared to a tax expense of $4.4 million for the same period in 2003. The tax expense for the six months ended June 30, 2004 includes federal tax expense of $11.5 million and state tax expense of $2.9 million. The tax expense for the same period in 2003 includes federal tax expense of $3.5 million and state tax expense of $0.9 million.

Income taxes for the three months ended June 30, 2004 was a tax expense of $9.1 million compared to a tax expense of $0.4 million for the same period in 2003. The tax expense for the three months ended June 30, 2004 includes federal tax expense of $7.3 million and state tax expense of $1.8 million. The tax expense for the same period in 2003 includes federal tax expense of $0.3 million and state tax expense of $0.1 million.

The tax expense in 2004 is due to a reduction in deferred tax assets without a tax benefit for the corresponding reduction in valuation allowance. Due to the uncertainty of realization of deferred tax assets related to net operating losses and other temporary differences, the Company's net deferred tax assets at December 5, 2003, were offset by a full valuation allowance of $131.5 million in accordance with SFAS No. 109. SOP 90-7 requires reductions in the valuation allowance subsequent to push down accounting as of December 5, 2003 should first reduce intangible assets until exhausted and thereafter be reported as a direct addition to paid-in-capital. Consequently, our effective tax rate in subsequent years will not benefit from reductions in the valuation allowance. For 2003, the tax expense resulting from a decrease in deferred tax assets was offset by a corresponding decrease in valuation allowance which had been established in an earlier year.

The effective income tax rate for the period ended June 30, 2004, differs from the statutory federal income tax rate of 35% due to state taxes and to the requirement that reductions to the valuation allowance as of December 5, 2003 (push down accounting) should first reduce intangible assets until exhausted. The effective income tax rate for the period ended June 30, 2003, differs from the statutory federal income tax rate of 35% due to state taxes.

As of June 30, 2004, the valuation allowance against net operating loss carryforwards was $31.2 million and the valuation allowance against other deferred tax assets was $85.5 million. As of December 31, 2003, a valuation allowance of $41.3 million was provided to account for potential limitations on utilization of net operating loss carryforwards, and a valuation allowance of $89.9 million was provided for other deferred tax assets. If unused, the net operating loss carryforward of $77.6 million generated in 2001 through 2003 will expire starting in 2021 and running through 2023.

EXHIBIT 99.2

NRG NORTHEAST GENERATING LLC

CONSOLIDATED FINANCIAL STATEMENTS

At June 30, 2004 and December 31, 2003, and for
the Three and Six Months Ended June 30, 2004 and 2003

NRG NORTHEAST GENERATING LLC

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NRG NORTHEAST GENERATING LLC

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	Reorganized Company	
	June 30, 2004	**December 31, 2003**
	(In thousands of dollars)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 110,409	$ 6,250
Restricted cash	3,725	4,198
Accounts receivable	217	306
Accounts receivable — affiliates	15,070	9,665
Inventory	119,570	107,441
Derivative instruments valuation	11,455	611
Prepayments and other current assets	36,735	33,812
Total current assets	297,181	162,283
Property, plant and equipment, net of accumulated depreciation of $25,980 and $2,911, respectively	834,136	843,832
Intangible assets, net of accumulated amortization of $8,323 and $523, respectively	195,883	213,687
Deferred income tax	84,717	91,565
Derivative instruments valuation	1,724	—
Other assets	7,382	7,355
Total assets	$1,421,023	$1,318,722
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities		
Note payable — affiliate	$ —	$ 30,000
Accounts payable	162	177
Accrued interest	—	2,557
Other accrued liabilities	47,444	51,225
Deferred income tax	451	453
Derivative instruments valuation	20,864	190
Total current liabilities	68,921	84,602
Other long-term obligations	11,557	7,528
Total liabilities	80,478	92,130
Commitments and contingencies		
Members' equity	1,340,545	1,226,592
Total liabilities and members' equity	$1,421,023	$1,318,722

The accompanying notes are an integral part of these consolidated financial statements.

NRG NORTHEAST GENERATING LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended		Six Months Ended	
	June 30, 2004	June 30, 2003	June 30, 2004	June 30, 2003
	(In thousands of dollars)			
Revenues	**$ 229,542**	$ 163,172	**$ 505,672**	$ 343,386
Operating costs	**146,310**	186,143	**322,046**	355,201
Depreciation	**11,109**	20,434	**23,068**	36,770
General and administrative expenses	**16,501**	8,120	**28,807**	19,639
Reorganization items	**27**	—	**348**	—
Restructuring and impairment charges	**—**	221,521	**—**	221,521
Income (loss) from operations	**55,595**	(273,046)	**131,403**	(289,745)
Other income (expense), net	**2,339**	(55)	**2,395**	7
Interest expense	**(1,391)**	(13,108)	**(677)**	(25,702)
Income (loss) before income taxes	**56,543**	(286,209)	**133,121**	(315,440)
Income tax expense (benefit)	**24,360**	(123,018)	**57,363**	(135,582)
Net income (loss)	**$ 32,183**	$(163,191)	**$ 75,758**	$(179,858)

The accompanying notes are an integral part of these consolidated financial statements.

NRG NORTHEAST GENERATING LLC

CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY

For the Three Months Ended June 30, 2004 and 2003
(Unaudited)

	Members' Unit	Members' Amount	Members' Contributions/ Distributions	Accumulated Net Income (Loss)	Accumulated Other Comprehensive Income	Total Members' Equity
			(In thousands of dollars)			
Balances at March 31, 2003 (Predecessor Company)	1,000	$ 1	$ 824,828	$ 50,835	$ 12,311	$ 887,975
Net loss				(163,191)		(163,191)
Impact of SFAS No. 133 for the three months ended June 30, 2003					(12,311)	(12,311)
Comprehensive loss						(175,502)
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 824,828	$ (112,356)	$ —	$ 712,473
Balances at March 31, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$1,251,915**	**$ 49,421**	**$ (15,270)**	**$1,286,067**
Net income				**32,183**		**32,183**
Impact of SFAS No. 133 for the three months ended June 30, 2004					**2,948**	**2,948**
Comprehensive income						**35,131**
Contribution from members			**19,347**			**19,347**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$1,271,262**	**$ 81,604**	**$ (12,322)**	**$1,340,545**

The accompanying notes are an integral part of these consolidated financial statements.

NRG NORTHEAST GENERATING LLC

CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY

For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Members'		Members' Contributions/ Distributions	Accumulated Net Income (Loss)	Accumulated Other Comprehensive Income	Total Members' Equity
	Unit	Amount				
				(In thousands of dollars)		
Balances at December 31, 2002 (Predecessor Company)	1,000	$ 1	$ 824,828	$ 67,502	$ 28,835	$ 921,166
Net loss				(179,858)		(179,858)
Impact of SFAS No. 133 for the six months ended June 30, 2003					(28,835)	(28,835)
Comprehensive loss						(208,693)
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 824,828	$ (112,356)	$ —	$ 712,473
Balances at December 31, 2003 (Reorganized Company)	**1,000**	**$ 1**	**$1,220,745**	**$ 5,846**	**$ —**	**$1,226,592**
Net income				**75,758**		**75,758**
Impact of SFAS No. 133 for the six months ended June 30, 2004					**(12,322)**	**(12,322)**
Comprehensive income						**63,436**
Contributions from members			**50,517**			**50,517**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$1,271,262**	**$ 81,604**	**$ (12,322)**	**$1,340,545**

The accompanying notes are an integral part of these consolidated financial statements.

NRG NORTHEAST GENERATING LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Reorganized Company	Predecessor Company
	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)	
Cash flows from operating activities		
Net income (loss)	**$ 75,758**	$(179,858)
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Depreciation	**23,068**	38,000
Gain on disposal of equipment	**—**	(1,230)
Unrealized gains on derivatives	**(4,217)**	(19,709)
Amortization of debt issuance costs	**—**	1,124
Amortization of intangible assets	**7,800**	—
Asset impairment	**—**	221,521
Deferred income taxes	**6,848**	(135,582)
Current tax expense — non cash contribution from members	**50,517**	—
Changes in assets and liabilities		
Accounts receivable	**89**	84,016
Accounts receivable/payable — affiliates	**(5,405)**	18,236
Inventories	**(12,129)**	5,016
Prepaid expenses	**(2,923)**	(8,148)
Accounts payable	**(15)**	(6,911)
Accrued interest	**(2,557)**	137
Other accrued liabilities	**(3,781)**	20,159
Other noncurrent assets and liabilities	**14,005**	(33,988)
Net cash provided by operating activities	**147,058**	2,783
Cash flows from investing activities		
Decrease in restricted cash	**473**	—
Proceeds from disposition of PP&E	**—**	4,876
Capital expenditures	**(13,372)**	(5,494)
Net cash used in investing activities	**(12,899)**	(618)
Cash flows from financing activities		
Principal payment of note payable — affiliate	**(30,000)**	—
Debt issuance costs	**—**	(7,537)
Net cash used in financing activities	**(30,000)**	(7,537)
Net change in cash and cash equivalents	**104,159**	(5,372)
Cash and cash equivalents		
Beginning of period	**6,250**	14,354
End of period	**$ 110,409**	$ 8,982

The accompanying notes are an integral part of these consolidated financial statements.

NRG NORTHEAST GENERATING LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Organization

NRG Northeast Generating LLC (the “Company” or “NRG Northeast”), a wholly owned indirect subsidiary of NRG Energy, Inc. (“NRG Energy”), owns electric power generation plants in the northeastern region of the United States. The Company’s members are Northeast Generation Holding LLC and NRG Eastern LLC, each of which owns a 50% interest in the Company and are directly held wholly owned subsidiaries of NRG Energy. The Company was formed in 1999 for the purpose of financing, acquiring, owning, operating and maintaining, through its subsidiaries and affiliates the power generation facilities owned by Arthur Kill Power LLC, Astoria Gas Turbine Power LLC, Connecticut Jet Power LLC, Devon Power LLC, Dunkirk Power LLC, Huntley Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, Oswego Harbor Power LLC and Somerset Power LLC.

Recent Developments

On May 14, 2003, NRG Energy and 25 of its direct and indirect wholly owned subsidiaries commenced voluntary petitions under Chapter 11 of the bankruptcy code in the United States Bankruptcy Court for the Southern District of New York. The Company and its direct subsidiaries were included in the Chapter 11 filing. During the bankruptcy proceedings, NRG Energy continued to conduct business and manage the companies as debtors in possession pursuant to sections 1107(a) and 1108 of the bankruptcy code. Two plans of reorganization were filed in connection with the restructuring efforts. The first, filed on May 14, 2003, and referred to as NRG Energy’s Plan of Reorganization, relates to NRG Energy and the other NRG Energy plan debtors. The second plan, relating to the Company, its subsidiaries and the South Central subsidiaries, referred to as the Northeast/South Central Plan of Reorganization, was filed on September 17, 2003. On November 24, 2003, the bankruptcy court entered an order confirming NRG Energy’s Plan of Reorganization and the plan became effective on December 5, 2003. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/South Central Plan of Reorganization and the plan became effective on December 23, 2003. In connection with NRG Energy’s emergence from bankruptcy, NRG Energy adopted fresh start accounting in accordance with AICPA Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code* (“SOP 90-7”) on December 5, 2003. NRG Energy’s fresh start accounting was applied to the Company on a push down accounting basis with the financial statement impact recorded as an adjustment to the December 6, 2003 members’ equity.

Northeast/ South Central Plan of Reorganization

The Northeast/ South Central Plan of Reorganization was proposed on September 17, 2003, after the necessary financing commitments were secured. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/ South Central Plan of Reorganization and the plan became effective on December 23, 2003. In connection with the order confirming the Northeast/ South Central Plan of Reorganization, the court entered a separate order which provides that the allowed amount of the bondholders’ claims shall equal in the aggregate the sum of (i) $1.3 billion plus (ii) any accrued and unpaid interest at the applicable contract rates through the date of payment to the indenture trustee plus (iii) the reasonable fees, costs or expenses of the collateral agent and indenture trustee (other than reasonable professional fees incurred from October 1, 2003) plus (iv) $19.6 million, ratably, for each holder of bonds based upon the current outstanding principal amount of the bonds and irrespective of (a) the date of maturity of the bonds, (b) the interest rate applicable to such bonds and (c) the issuer of the bonds.

The creditors of NRG Northeast and South Central subsidiaries were unimpaired by the Northeast/ South Central Plan of Reorganization. The creditors holding allowed general secured claims were paid in cash, in full on the effective date of the Northeast/ South Central Plan of Reorganization. Holders of allowed unsecured claims received either (i) cash equal to the unpaid portion of their allowed unsecured claim,

(ii) treatment that leaves unaltered the legal, equitable and contractual rights to which such unsecured claim entitles the holder of such claim, (iii) treatment that otherwise renders such unsecured claim unimpaired pursuant to section 1124 of the bankruptcy code or (iv) such other, less favorable treatment that is confirmed in writing as being acceptable to such holder and to the applicable debtor.

2. Summary of Significant Accounting Policies

Basis of Presentation

As used in these unaudited interim consolidated financial statements, “Predecessor Company” refers to the Company prior to NRG Energy’s emergence from bankruptcy. “Reorganized Company” refers to the Company after NRG Energy’s emergence from bankruptcy.

Between May 14, 2003 and December 23, 2003, the Company operated as a debtor-in-possession under the supervision of the Bankruptcy Court. The Company’s financial statements for reporting periods within that timeframe were prepared in accordance with the provisions of SOP 90-7.

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with the Securities and Exchange Commission’s or “SEC” regulations for interim financial information. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. The accounting policies followed are set forth in Note 2 to the Company’s annual audited consolidated financial statements for the year ended December 31, 2003. The following notes should be read in conjunction with such policies and other disclosures. 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 necessary to present fairly the Company’s consolidated financial position as of June 30, 2004 and December 31, 2003, the results of its operations, and members’ equity for the three and six months ended June 30, 2004 and 2003 and the cash flows for the six months ended June 30, 2004 and 2003. Certain prior-year amounts have been reclassified for comparative purposes.

Comparability of Financial Information

Due to NRG Energy’s adoption of Fresh Start as of December 5, 2003, the Reorganized Company’s consolidated balance sheet, statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company’s financial statements and are not comparable in certain respects to the financial statements prior to the application of push down accounting from NRG Energy’s fresh start accounting. A black line has been drawn on the accompanying consolidated financial statements (excluding the balance sheet) to separate and distinguish between the Reorganized Company and the Predecessor Company.

3. Other Charges

Restructuring and impairment charges and reorganization items included in operating costs and expenses in the consolidated statements of operations include the following:

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)			
Impairment charges	**$ —**	$ 221,521	**$ —**	$ 221,521
Reorganization items	**27**	—	**348**	—
	$ 27	$ 221,521	**$ 348**	$ 221,521

Restructuring and Impairment Charges

The Company reviewed the recoverability of its long-lived assets in accordance with the guidelines of SFAS No. 144. As a result of this review, no impairment charges were recorded for the three and six months ended June 30, 2004. The Company recorded $221.5 million of impairment charges for the three and six months ended June 30, 2003, which included the following:

		Predecessor Company		
Project Name	Project Status	Three Months Ended June 30, 2003	Six Months Ended June 30, 2003	Fair Value Basis
Devon Power LLC	Operating at a loss	$ 64,198	$ 64,198	Projected cash flows
Middletown Power LLC	Operating at a loss	157,323	157,323	Projected cash flows
Total impairment charges		$ 221,521	$ 221,521	

Reorganization Items

The Company incurred total reorganization items of $27,000 and $0.3 million for the three and six months ended June 30, 2004. All reorganization costs have been incurred since the Company filed for bankruptcy in May 2003. These costs consist of bankruptcy related charges primarily related to professional fees.

4. Inventory

Inventory, which is valued at the lower of weighted average cost or market, consists of:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Fuel oil	$ 80,134	$ 70,331
Spare parts	24,775	24,947
Coal	13,571	12,163
Natural gas	1,090	—
Total inventory	$119,570	$ 107,441

5. Property, Plant and Equipment

The major classes of property, plant and equipment were as follows:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Facilities, machinery and equipment	$802,476	$ 802,173
Land and improvements	34,266	34,266
Construction in progress	22,759	9,689
Office furnishings and equipment	615	615
Total property, plant and equipment	860,116	846,743
Accumulated depreciation	(25,980)	(2,911)
Property, plant and equipment, net	$834,136	$ 843,832

6. Asset Retirement Obligation

Effective January 1, 2003, the Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations* (“SFAS No. 143”). SFAS No. 143 requires an entity to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The Company identified certain retirement obligations related to environmental matters for ash disposal site closures. The Company also identified similar other asset retirement obligations that could not be calculated because the assets associated with the retirement obligations were determined to have an indeterminate life. The adoption of SFAS No. 143 resulted in recording a $0.2 million increase to property, plant and equipment and a $0.3 million increase to other long-term obligations. The cumulative effect of adopting SFAS No. 143 was recorded as a $0.1 million increase to depreciation expense and a $0.1 million increase to operating costs as the Company considered the cumulative effect to be immaterial.

The following represents the balances of the asset retirement obligation as of January 1, 2004, and accretion of the asset retirement obligation for the six months ended June 30, 2004, which is included in other long-term obligations in the consolidated balance sheet.

	Reorganized Company		
	Beginning Balance January 1, 2004	Accretion for the Six Months Ended June 30, 2004	Ending Balance June 30, 2004
	(In thousands of dollars)		
Dunkirk Power LLC	$ 2,677	$ 91	$2,768
Huntley Power LLC	4,346	148	4,494
Somerset Power LLC	505	17	522
	$ 7,528	$ 256	$7,784

7. Intangible Assets

Upon the application of push down accounting, the Company established certain intangible assets for power sales agreements and plant emission allowances. These intangible assets will be amortized over their respective lives based on a straight-line or units of production basis to resemble the Company's realization of such assets.

Power sale agreements will be amortized as a reduction to revenue over the terms and conditions of each contract. The power sale agreements were fully amortized in May 2004. Emission allowances will be amortized as additional fuel expense based upon the actual level of emissions from the respective plants through 2023. Aggregate amortization recognized for the three and six months ended June 30, 2004, was approximately $2.8 million and $7.8 million, respectively. The annual aggregate amortization for each of the five succeeding years is expected to approximate $11.6 million.

Intangible assets were reduced by $10.0 million in connection with the recognition of certain tax credits to be claimed on the Company's New York State franchise tax return.

Intangible assets consisted of the following:

	Power Sale Agreements	Emission Allowances	Total
		(In thousands of dollars)	
Original balances as of December 6, 2003	$ 3,140	$211,070	$214,210
Amortization	(523)	—	(523)
Balances as of December 31, 2003	2,617	211,070	213,687
Amortization	(2,617)	(5,183)	(7,800)
Other adjustments	—	(10,004)	(10,004)
Balances as of June 30, 2004	$ —	$195,883	$195,883

Predecessor Company

The Company had intangible assets of $22.2 million at June 30, 2003 which were amortized and consisted of future transmission service being provided under long-term contracts. Aggregate amortization expenses recognized for the three and six months ended June 30, 2003 was approximately $0.6 million and $1.2 million, respectively.

8. Note Payable — Affiliate

On June 15, 2002, NRG Energy loaned the Company $30 million to fund capital expenditures. The note payable bears interest at the three-month London Interbank Offered Rate plus 0.5%. The note payable is subordinate to the debt of NRG Energy and is subject to the terms and conditions of the senior secured bonds' indenture. The note payable was paid along with accrued interest of $1.0 million in March 2004. Accordingly, the Company has classified this loan as a short-term affiliated note payable at December 31, 2003.

9. Derivative Instruments and Hedging Activity

Statement of Financial Accounting Standards SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133), as amended, requires the Company to record all derivatives on the consolidated balance sheet as assets or liabilities at fair value. For derivatives designated as cash flow hedges, the effective portion of the changes in fair value of the derivatives are recorded in accumulated other comprehensive income ("OCI") and subsequently recognized in earnings when the hedged items impact 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. Changes in the fair value of nonhedge derivatives will be immediately recognized in earnings. Additionally, many of the Company's commodity sales and purchase agreements that otherwise would be required to follow derivative accounting qualify as normal purchases and sales under SFAS No. 133, and are therefore exempt from fair value accounting treatment.

SFAS No. 133 applies to the Company's long-term power sales contracts, long-term fuel purchase contracts and other energy related commodities financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect investments in fuel inventories. At June 30, 2004, the Company had various commodity contracts extending through December 2005.

Energy Related Commodities

The Company is exposed to commodity price variability in electricity, emission allowances, natural gas, oil and coal used to meet fuel requirements. In order to manage these commodity price risks, the Company entered into financial instruments, which may take the form of fixed price, floating price or indexed sales or purchases, and options, such as puts, calls, basic transactions and swaps. Certain of these transactions have been designated as cash flow hedges. The Company has accounted for these derivatives by recording the effective portion of the cumulative gain or loss on the derivative instruments as a component of OCI in members' equity. The Company recognizes deferred gains and losses into earnings in the same period or periods during which the hedged transaction affects earnings. Such reclassifications are included on the same line of the statement of operations in which the hedged item is recorded.

Accumulated Other Comprehensive Income

The following table summarizes the effects of SFAS No. 133 on the Company's accumulated other comprehensive income balance attributable to hedged derivatives:

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands)			
Gains/(Losses)				
Beginning Balance	**$ (15,270)**	$ 12,311	**$ —**	$ 28,835
Unwound from OCI during period				
Due to unwinding of previously deferred amounts	**8,556**	(12,311)	**9,133**	(28,835)
Mark to market hedge contracts	**(5,608)**	—	**(21,455)**	—
Ending Balance	**$ (12,322)**	$ —	**$ (12,322)**	$ —
Losses expected to unwind from OCI during next 12 months	**$ (13,418)**	$ —	**$ (13,418)**	$ —

Reorganized Company

Losses of $8.6 million and $9.1 million were reclassified from OCI to current period earnings during the three and six months ended June 30, 2004, due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the consolidated statement of operations in which the hedged items are recorded. Also, during the three and six months ended June 30, 2004, the Company recorded losses in OCI of approximately $5.6 million and $21.5 million, respectively, related to changes in the fair values of derivatives accounted for as hedges.

The net balance in OCI relating to SFAS No. 133 as of June 30, 2004, was an unrecognized loss of approximately $12.3 million. The Company expects $13.4 million of deferred net losses on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

Predecessor Company

Gains of $12.3 million and $28.8 million were reclassified from OCI to current period earnings during the three and six months ended June 30, 2003, due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the consolidated statement of operations in which the hedged items are recorded. Also, during the three and six months ended June 30, 2003, the Company recorded no amounts related to changes in the fair values of derivatives accounted for as hedges. The net balance in OCI relating to SFAS No. 133 as of June 30, 2003, was $0.

Statement of Operations

The following table summarizes the pre-tax effects of nonhedge derivatives on the Company's consolidated statements of operations:

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In thousands)			
Gains/(Losses)				
Revenues	**$ 6,126**	$ 23,391	**$ 5,854**	$ 21,152
Operating costs	**(1,124)**	363	**(1,637)**	(1,443)
Total statement of operations impact before tax	**$ 5,002**	$ 23,754	**$ 4,217**	$ 19,709

No ineffectiveness was recognized on commodity cash flow hedges during the three and six months ended June 30, 2004 and 2003.

The Company's earnings for the three months ended June 30, 2004 and 2003, were increased by unrealized gains of $5.0 million and a $23.8 million, respectively. For the six months ended June 30, 2004 and 2003, the Company's earnings increased by unrealized gains of $4.2 million and $19.7 million, respectively, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

At June 30, 2004, the Company had hedge and nonhedge energy related commodities financial instruments extending through December 2005.

10. Commitments and Contingencies

Environmental Matters

The construction and operation of power projects are subject to stringent environmental and safety protection and land use laws and regulations in the United States. These laws and regulations generally require lengthy and complex processes to obtain licenses, permits and approvals from federal, state and local agencies. If such laws and regulations become more stringent and NRG Northeast's facilities are not exempted from coverage, NRG Northeast could be required to make extensive modifications to further reduce potential environmental impacts. Also, NRG Northeast could be held responsible under environmental and safety laws for the cleanup of pollutant releases at its facilities or at off-site locations where it has sent wastes.

NRG Northeast and its subsidiaries strive to exceed the standards of compliance with applicable environmental and safety regulations. Nonetheless, NRG Northeast expects that future liability under or compliance with environmental and safety requirements could have a material effect on its operations or competitive position. It is not possible at this time to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of possible changes to environmental and safety regulations, regulatory interpretations or enforcement policies. In general, the effect of future laws or regulations is expected to require the addition of pollution control equipment or the imposition of restrictions on NRG Northeast's operations.

As part of acquiring existing generating assets, NRG Northeast has inherited certain environmental liabilities associated with regulatory compliance and site contamination. Often potential compliance implementation plans are changed, delayed or abandoned due to one or more of the following conditions: (a) extended negotiations with regulatory agencies, (b) a delay in promulgating rules critical to dictating the design of expensive control systems, (c) changes in governmental/regulatory personnel, (d) changes in governmental priorities or (e) selection of a less expensive compliance option than originally envisioned.

In response to liabilities associated with these activities, NRG Northeast has established accruals where reasonable estimates of probable liabilities are possible. At June 30, 2004 and December 31, 2003, NRG Northeast has established such accruals in the amount of approximately $3.8 million primarily related to its Arthur Kill and Astoria projects. NRG Northeast has not used discounting in determining its accrued liabilities for environmental remediation and no claims for possible recovery from third party issuers or other parties related to environmental costs have been recognized in NRG Northeast's consolidated financial statements. NRG Northeast adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates are adjusted to reflect new information.

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility, including an electric generating facility, may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products located at the facility, and may be held liable to a governmental entity or to third parties for property damage, personal injury and investigation and remediation costs incurred by the party in connection with any releases or threatened releases. These laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended by the Superfund Amendments and Reauthorization Act of 1986, impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and courts have interpreted liability under such laws to be strict (without fault) and joint and several. The cost of investigation, remediation or removal of any hazardous or toxic substances or petroleum products could be substantial. Although NRG Northeast has been involved in on-site contamination matters, to date, NRG Northeast has not been named as a potentially responsible party with respect to any off-site waste disposal matter.

Coal ash is produced as a by-product of coal combustion at the Dunkirk, Huntley, and Somerset Generating Stations. NRG Northeast attempts to direct its coal ash to beneficial uses. Even so, significant amounts of ash are landfilled at on-site and off-site locations. At Dunkirk and Huntley, ash is disposed at landfills owned and operated by NRG Northeast. No material liabilities outside the costs associated with closure, post-closure care and monitoring are expected at these facilities. NRG Northeast maintains financial assurance to cover costs associated with closure, post-closure care and monitoring activities. In the past, NRG Northeast has provided financial assurance via financial test and corporate guarantee. As a result of NRG Energy's debt restructuring, NRG Northeast was required to re-establish financial assurance via an instrument requiring complete collateralization of closure and post-closure-related costs, such costs at June 30, 2004, were estimated at approximately $5.8 million and is included in other assets. NRG Northeast provided such financial assurance via a trust fund established in this amount on April 30, 2003.

NRG Northeast must also maintain financial assurance for closing interim status Resource Conservation and Recovery Act facilities at the Devon, Middletown, Montville and Norwalk Generating Stations. Previously, NRG Northeast has provided financial assurance via financial test. As a result of NRG Energy's debt restructuring, NRG Northeast was required to re-establish financial assurance via an instrument requiring complete collateralization of closure and post-closure-related costs, such costs at June 30, 2004 were estimated at approximately $1.5 million. NRG Northeast provided such financial assurance via a trust fund established in this amount on April 30, 2003.

Historical clean-up liabilities were inherited as a part of acquiring the Somerset, Devon, Middletown, Montville, Norwalk, Arthur Kill and Astoria Generating Stations. NRG Northeast has recently satisfied clean-up obligations associated with the Ledge Road property (inherited as part of the Somerset acquisition). Site contamination liabilities arising under the Connecticut Transfer Act at the Devon, Middletown, Montville and Norwalk Stations have been identified and are currently being refined as part of on-going site investigations. NRG Northeast does not expect to incur material costs associated with completing the investigations at these Stations or future work to cover and monitor landfill areas pursuant to the Connecticut requirements. Remedial obligations at the Arthur Kill Generating Station have been established in discussions between NRG Northeast and the New York State DEC and are estimated at $1.0 million. Remedial investigations are on going at the Astoria Generating Station. At this time, NRG Northeast's long-term cleanup liability at this site is estimated at $1.5 million.

At June 30, 2004 and December 31, 2003, the Company had recorded an accrual in the amount of $2.1 million to cover penalties associated with historical opacity exceedances.

Contractual Commitments

In connection with the acquisition of certain generating facilities, NRG Northeast entered into various long-term transition agreements and standard offer agreements that obligated NRG Northeast to provide its customers, primarily the previous owners of the acquired facilities, with a certain portion of the energy and capacity output of the acquired facilities.

During 1999, the Company acquired certain generating facilities from Connecticut Light and Power Company ("CL&P"). NRG Power Marketing Inc. ("NRG Power Marketing") also entered into a four-year standard offer agreement that requires NRG Power Marketing to provide to CL&P a portion of its load requirements through the year 2003 at a fixed rate of $43.83 per MWh. Through its agency agreement with the Company, NRG Power Marketing utilizes in part, the capacity available in the Connecticut facilities in order to serve the contract. This agreement ended in December 2003.

During 1999, the Company acquired the Oswego generating facilities from Niagra Mohawk Power Corporation ("NiMo") and entered into a four-year transition power sales contract with NiMo in order to hedge NiMo's transition to market rates. Under the agreement, NiMo agreed to pay to Oswego Power a fixed monthly price plus start up fees for the right to claim, at a specified delivery point(s), the installed capacity of unit 5 and for the right to exercise an option for an additional 350 MW of installed capacity. This agreement expired in October 2003. During 1999, the Company also acquired the Huntley and Dunkirk facilities from NiMo and entered into similar four year transition power sales contracts. Under the agreements, the Company agreed to provide capacity and to deliver energy to NiMo for a set price. These agreements expired in October 2003.

NRG Power Marketing has entered into a wholesale standard offer service agreement with Blackstone Valley Electric Company, Eastern Edison Company and Newport Electric Corporation (collectively the

"EUA Companies"). Under the agreement, NRG Power Marketing is obligated to provide each of the EUA Companies with firm all-requirements electric service, including capacity, energy, reserves, line losses and related services necessary to serve the aggregate load attributable to retail customers taking standard offer service. The price the EUA Companies pay to NRG Power Marketing for each unit of electricity is a fixed price plus a fuel adjustment factor. On June 8, 2004, the parent company of the EUA Companies terminated the agreement.

In July 2002, NRG Power Marketing reached a tentative agreement with CL&P that would result in increased compensation to NRG Power Marketing, a supplier of CL&P's wholesale supply agreement. CL&P filed an emergency petition with the Connecticut Department of Public Utility Control ("DPUC") asking for approval of a shift of wholesale supply agreement revenues, effective August 1, 2002, through December 31, 2003, that would reallocate 0.7 cents per kilowatt-hour in the wholesale price paid to existing suppliers. On July 26, 2002, the DPUC denied the request of CL&P for an emergency letter ruling.

NYISO Claims

In November 2002, the NYISO notified the Company 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. The New York City mitigation adjustments totaled $11.5 million. NRG Northeast did not contest that claim and it has been fully reserved. The general NYISO billing adjustment issue totaled $10.2 million and related to NYISO's concern that the Company would not have sufficient revenue to cover for subsequent revisions to its energy market settlements. At both June 30, 2004 and December 31, 2003, the NYISO held $4.5 million in escrow for such future settlement revision.

Guarantees

In November 2002, the FASB issued FASB Interpretation No. ("FIN") 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* The initial recognition and initial measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year end. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. The interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. The interpretation also clarifies the requirements related to the recognition of a liability by a guarantor at the inception of the guarantee for the obligations the guarantor has undertaken in issuing the guarantee.

In connection with the application of push down accounting, all outstanding guarantees were considered new; accordingly, the Company applied the provisions of FIN 45 to all of these guarantees. Each guarantee was reviewed for the requirement to recognize a liability at inception.

The Company is directly liable for the obligations of certain of its affiliates pursuant to guarantees relating to certain of their performance obligations. In addition, in connection with the purchase and sale of fuel, emission credits and power generation products to and from third parties with respect to the operation of some of the Company's generation facilities, the Company may be required to guarantee a portion of the obligations of certain of its subsidiaries. The Company also provides performance guarantees to third parties on behalf of NRG Power Marketing in relation to certain of its sales and supply agreements.

At June 30, 2004, the Company's obligations pursuant to its guarantees of the performance obligations of its affiliates and subsidiaries totaled approximately $2.3 million.

The nature and details of the Company's guarantees were as follows:

Name	Guarantee/ Maximum Exposure — June 30, 2004	Nature of Guarantee	Expiration Date	Triggering Event
		(In thousands of dollars)		
Astoria/ Arthur Kill	Indeterminate	Performance	None stated	Nonperformance
Devon/ Middletown/ Montville/ Norwalk	$2,339	Performance	None stated	Nonperformance

In addition to these guarantees, the Company is a guarantor under the debt issued by the Company's ultimate parent, NRG Energy. NRG Energy issued $1.25 billion of 8% Second Priority Notes on December 23, 2003, due and payable on December 15, 2013. On January 28, 2004, NRG Energy also issued $475.0 million of Second Priority Notes, under the same terms and indenture as its December 23, 2003 offering.

NRG Energy's payment obligations under the notes and all related Parity Lien Obligations are guaranteed on an unconditional basis by each of NRG Energy's current and future restricted subsidiaries, of which the Company is one. The notes are jointly and severally guaranteed by each of the guarantors. The subsidiary guarantees of the notes are secured, on a second priority basis, equally and ratably with any future Parity Lien Debt, by security interests in all of the assets of the guarantors, except certain excluded assets, subject to liens securing parity lien debt and other permitted prior liens.

The Company's obligations pursuant to its guarantees of the performance, equity and indebtedness obligations were as follows:

	Guarantee/ Maximum Exposure	Nature of Guarantee	Expiration Date	Triggering Event
		(In thousands of dollars)		
NRG Energy Second Priority Notes due 2013	$1,753,000	Obligations under credit agreement	2013	Nonperformance

Legal Issues

Consolidated Edison Co. of New York v. Federal Energy Regulatory Commission, Docket No. 01-1503

Consolidated Edison and others petitioned the United States Court of Appeals for the District of Columbia Circuit for review of certain FERC orders in which FERC refused to order a redetermination of prices in the New York Independent System Operator, or NYISO, operating reserve markets for the period from January 29, 2000 to March 27, 2000. Petitioners alleged that the prices in the operating reserves markets were unduly elevated by approximately $65 million as a result of market power abuse and operating flaws. On November 7, 2003, the court issued a decision which found the NYISO's method of pricing spinning reserves violated the NYISO tariff. The court also required FERC to determine whether the exclusion from the non-spinning market of a generating facility known as Blenheim-Gilboa and resources located in western New York also constituted a tariff violation and/or whether these exclusions enabled NYISO to use its Temporary Extraordinary Procedure, or TEP, authority to require refunds. On June 25, 2004, the NYISO filed a motion requesting that it be permitted to supplement the record. The motion indicated that FERC had the authority to order refunds in the case because the failure to model Blenheim-Gilboa constituted a TEP. On July 16, 2004, we filed an objection to the NYISO's motion, asserting that the failure to model was a conscious decision of the owners of that facility and that NYISO's authority under TEP did not apply. It is unclear at this time whether FERC will require refunds, much less the amount of any such refunds. If 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 will share responsibility for payment of such refunds, under the petitioners' theory and calculations the cumulative exposure to our above-listed entities could exceed $23 million.

Electricity Consumers Resource Council v. Federal Energy Regulatory Commission, Case No. 03-1449

On December 19, 2003, the Electricity Consumers Resource Council ("ECRC") appealed to the United States Court of Appeals for the District of Columbia Circuit a recent decision by FERC approving the implementation of a demand curve for the New York installed capacity ("ICAP") market. ECRC claims that the implementation of the ICAP demand curve violates section 205 of the Federal Power Act because it constitutes unreasonable ratemaking. The Company is party to this appeal and will contest FERC's assertions, but at this time cannot assess what the eventual outcome will be.

Connecticut Light & Power Company v. NRG Power Marketing, Inc., Docket No. 3:01-CV-2373 (AWT), pending in the United States District Court, District of Connecticut

This matter involves a claim by Connecticut Light & Power Company ("CL&P") for recovery of amounts allegedly owed for congestion charges under the terms of a Standard Offer Services ("SOS") contract between the parties, dated October 29, 1999. CL&P has served and filed its motion for summary judgment to which NRG Power Marketing, Inc. ("PMI") filed a response on March 21, 2003. CL&P has withheld approximately $30 million from amounts owed to PMI, claiming that it has the right to offset those amounts under the contract. PMI has counterclaimed seeking to recover those amounts, arguing among other things that CL&P has no rights under the contract to offset them. By reason of the previous bankruptcy stay, the court has not ruled on the pending motion. On November 6, 2003, the parties filed a joint stipulation for relief from the automatic stay in order to allow the proceeding to go forward, and PMI has supplemented the record on the pending summary judgment motion. PMI cannot estimate at this time the likelihood of an unfavorable outcome in this matter.

The State of New York and Erin M. Crotty, as Commissioner of the New York State Department of Environmental Conservation v. Niagara Mohawk Power Corporation, NRG Energy, Inc., NRG Dunkirk Operations, Inc., Dunkirk Power, LLC, NRG Huntley Operations, Inc., Huntley Power, LLC, NRG Northeast Generating, LLC, Northeast Generation Holding, LLC, NRG Eastern, LLC and NRG Operating Services, Inc., United States District Court for the Western District of New York, Civil Action No. 02-CV-0024S

In January 2002, the New York Department of Environmental Conservation ("DEC") sued Niagara Mohawk Power Corporation ("NiMo"), NRG Energy and certain of NRG Energy's affiliates in federal court in New York. The complaint asserted that projects undertaken at NRG Energy's Huntley and Dunkirk plants by NiMo, the former owner of the facilities, required preconstruction permits pursuant to the Clean Air Act and that the failure to obtain these permits violated federal and state laws. In July, 2002, the NRG entities filed a motion to dismiss. On March 27, 2003 the court dismissed the complaint against the NRG entities with prejudice as to the federal claims and without prejudice as to the state claims. On December 31, 2003, the trial court granted the state's motion to amend the complaint to again sue NRG Energy and various affiliates in this same action in the federal court in New York, asserting against them violations of operating permits and deficient operating permits at the Huntley and Dunkirk plants. The parties have commenced written discovery, and the court has scheduled the trial on liability issues for March, 2006. For several months, the parties have been engaged in discussions respecting possible settlement of this matter. If the case ultimately is litigated to an unfavorable outcome that could not be addressed otherwise, NRG Energy has estimated that the total investment that would be required to install pollution control devices could be as high as $300 million over a ten to twelve-year period. The NRG entities also could be found responsible for payment of certain penalties and fines.

Niagara Mohawk Power Corporation v. NRG Energy, Inc., Huntley Power, LLC, and Dunkirk Power, LLC, Supreme Court, State of New York, County of Onondaga, Case No. 2001-4372

NRG Energy has asserted that NiMo is obligated to indemnify it for any related compliance costs associated with resolution of the above enforcement action. NiMo has filed suit in state court in New York seeking a declaratory judgment with respect to its obligations to indemnify NRG Energy under the asset sales agreement. NRG Energy has pending a summary judgment motion on its entitlement to be reimbursed by NiMo for attorneys' fees incurred in the enforcement action.

Huntley Power LLC

On April 30, 2003, the Huntley Station submitted a self-disclosure letter to the DEC reporting violations of applicable sulfur in fuel limits, which had occurred during 6 days in March 2003 at the chimney stack serving Huntley Units 63-66. The Huntley Station self-disclosed that the average sulfur emissions rates for those days had been 1.8 lbs/mm BTU, rather than the maximum allowance of 1.7 lbs/mm BTU. NRG Huntley Operations discontinued use of Unit 65 (the only unit utilizing the subject stack at the time) and has kept the remaining three units off line until adherence with the applicable standard is assured. On May 19, 2003, the DEC issued Huntley Power LLC a Notice of Violation. Huntley Power LLC has met with the DEC to discuss the circumstances surrounding the event and the appropriate means of resolving the matter. Huntley Power LLC does not know what relief the DEC will seek through an enforcement action. Under applicable provisions of the Environmental Conservation Law, the DEC asserts that it may impose a civil penalty up to $10,000, plus an additional penalty not to exceed $10,000 for each day that a violation continues and may enjoin continuing violations.

Niagara Mohawk Power Corporation v. Dunkirk Power LLC, NRG Dunkirk Operations, Inc. Huntley Power LLC, NRG Huntley Power Operations, Inc., Oswego Power LLC and NRG Oswego Operations Inc., Supreme Court, Erie County, Index No. 1-2000-8681 — Station Service Dispute

On October 2, 2000, plaintiff Niagara Mohawk Power Corporation ("NiMo") commenced this action against NRG Energy to recover damages plus late fees, less payments received through the date of judgment, as well as any additional amounts due and owing, for electric service provided to the Dunkirk Plant after September 18, 2000. NiMo claims that NRG Energy has failed to pay retail tariff amounts for utility services commencing on or about June 11, 1999. Plaintiff has alleged breach of contract, suit on account, violation of statutory duty, and unjust enrichment claims. On or about October 23, 2000, NRG Energy served an answer denying liability and asserting affirmative defenses.

After proceeding through discovery, and prior to trial, the parties and the court entered into a Stipulation and Order filed August 9, 2002, consolidating this action with two other actions against the Company's Huntley and Oswego subsidiaries, both of which cases assert the same claims and legal theories for failure to pay retail tariffs for utility services at those plants.

On October 8, 2002, a Stipulation and Order was filed in the Erie County Clerk's Office staying this action, pending submission to FERC of some or all of these disputes. NRG Energy cannot make an evaluation of the likelihood of an unfavorable outcome. The cumulative potential loss could amount to some $40 million.

Niagara Mohawk Power Corporation v. Huntley Power LLC, NRG Huntley Operations, Inc., NRG Dunkirk Operations, Inc., Dunkirk Power LLC, Oswego Harbor Power LLC, and NRG Oswego Operations, Inc., Case File November 26, 2002 in Federal Energy Regulatory Commission Docket No. EL 03-27-000

This is the companion action filed by NiMo at FERC, similarly asserting that NiMo is entitled to receive retail tariff amounts for electric service provided to the Huntley, Dunkirk and Oswego plants. On October 31, 2003, the FERC Trial Staff, a party to the proceedings, filed a reply brief in which it supported and agreed with each position taken by the Company's facilities. In short, the staff argued that the Company's facilities: (1) self-supply station power under the NYISO tariff (which took effect on April 1, 2003) in any month during which they produce more energy than they consume and, as such, should not be assessed a retail rate; (2) are connected only to transmission facilities and, as such, at most should only pay NiMo a FERC-approved transmission rate; and (3) should be allowed to net consumption and output even if power is injected into the grid at a different point from which it is drawn off. The Company is presently awaiting a ruling by FERC. At this stage of the proceeding, NRG Energy cannot estimate the likelihood of success on this action. As noted above, the cumulative potential loss could amount to some $40 million.

11. Regulatory Issues

New England

Effective March 1, 2003, ISO-NE implemented its version of standard market design ("SMD"). This change dramatically modifies the New England market structure by incorporating locational marginal pricing ("LMP" — pricing by location rather than on a New England wide basis). Even though NRG Northeast views this change as a significant improvement to the existing market design, NRG Northeast still views the market in New England as incapable of allowing NRG Northeast to recover its costs and provide a reasonable return on investment. Consequently, on February 26, 2003, Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC and NRG Power Marketing (collectively, the "NRG Filers") filed and requested a cost of service rate with FERC for most of its Connecticut fleet, requesting a February 27th effective date. The NRG Filers remain committed to working with ISO-NE, FERC and other stakeholders to continue to improve the New England market that will hopefully make further reliance on a cost of service rate unnecessary. On March 25, 2003, the FERC issued an order (the "Order") in response to the NRG Filers' Joint Motion for Emergency Expedited Issuance of Order by March 17, 2003, in Docket No. ER03-563-000 (the "Emergency Motion"). In the Emergency Motion, the NRG Filers requested that FERC accept the NRG Filers' reliability must-run agreements and assure the NRG Filers' recovery of deferred maintenance costs for their New England generating facilities prior to the peak summer season. FERC accepted the NRG Filers' filing as to the recovery of spring 2003 maintenance costs, subject to refund. FERC's Order authorizes the ISO New England Inc. to begin collecting these maintenance costs in escrow for the benefit of the NRG Filers as of February 27, 2003. Several intervenors protested the Emergency Motion. FERC did not rule on the remainder of the issues to allow for further time to consider protests it received related to the filings.

On April 25, 2003, FERC issued an order rejecting the remaining part of the proposed cost of service agreements including the monthly cost-based payments, citing certain policy determinations regarding cost of service agreements. Rather, FERC instructed ISO-NE to establish temporary bidding rules that would permit selected units (units with capacity factors of 10% or less during 2002), operating within designated congestion areas, such as Connecticut, to raise their bids to allow them the opportunity to recover their fixed and variable costs through the market. In May and June 2003, the ISO-NE revised its market rules to facilitate "peaking unit safe harbor," or "PUSH," bidding. On July 24, 2003, FERC clarified that the capacity factor of 10% or less applies to units rather than stations. Therefore, on a unit basis, all of the Company's facilities qualify to bid under the temporary rules, except Middletown units 2 and 3. The PUSH bidding rule will remain in place until ISO-NE implements locational installed capacity payments, which FERC mandated ISO-NE implement no later than June 1, 2004. On March 1, 2004, ISO-NE filed a locational capacity proposal with FERC. Under the proposal, generators that are needed for reliability and have a capacity factor of 15% or less in 2003 are eligible for a monthly capacity payment of $5.38 per KW-month. Most of the Company's generators located in Connecticut satisfy this requirement.

Consistent with expectations, PUSH bidding has not yielded sufficient revenues to cover all costs for most of the Company's affected facilities. On January 16, 2004, the Company filed proposed reliability-must-run agreements ("RMR agreements") with FERC for the following facilities: Devon station units 11-14, Middletown station and Montville station. The RMR agreement filings requested FERC to establish cost of service rates. On March 18, 2004 FERC granted us a one day suspension of the rates, subject to refund, set the case for hearing and consolidated the case with other similar NRG cases before a settlement judge. In the March 18, 2004 order the FERC ruled that the RMR agreements would expire with the implementation of a locational installed capacity ("LICAP") market, which was expected to begin on June 1, 2004. On April 14, 2004 we filed a motion for rehearing with FERC requesting FERC to revise the termination date ruling. As of this date, FERC has not responded to the rehearing request.

On February 6, 2004, the Company filed updated maintenance schedules for the tracking mechanism that provides for the payment by certain NEPOOL participants of third party maintenance expense incurred by NRG. On April 1, 2004 FERC accepted the revised schedules, subject to refund, set the case for hearing and consolidated the case with other similar NRG cases before a settlement judge. In the April 1, 2004 order the FERC ruled that the tracking mechanism would expire with the implementation of a LICAP market, which is expected to begin on June 1, 2004. On April 14, 2004 the Company filed a motion for rehearing with FERC requesting FERC to revise the termination date ruling. As of this date, FERC has not responded to the rehearing request.

In addition to the facilities noted above, the following of the Company's quick-start facilities in Connecticut have submitted PUSH bids that have been approved by FERC: Cos Cob, Franklin Drive, Banford, and Torrington. In August 2002, the Company and ISO-NE submitted RMR Agreements to FERC for approval for the following facilities: Devon 7, 8 and 10. In October 2002, Devon 10 was retired because ISO-NE determined that the facility was no longer needed for reliability. In December 2002, FERC approved the RMR Agreements. Numerous parties filed rehearing motions and on September 21, 2004, FERC issued an order affirming in part its prior approval. Specifically, the order reduced the compensation under the agreement by approximately $1 million. The existing RMR agreement between ISO-NE and the Company covering Devon station units 7 and 8 terminated on September 30, 2003. On October 2, 2003, the Company filed with FERC to extend the existing RMR agreement for the two Devon units. On December 1, 2003, FERC granted a one-day suspension of the rates, subject to refund, set the case for hearing and appointed a settlement judge. On February 25, 2004, a FERC sponsored technical conference occurred to review the costs associated with the two Devon units. In the technical conference, the costs relevant to the RMR agreements were discussed. ISO-NE has indicated in a letter dated February 27, 2004, that one of the Devon units will no longer be needed for reliability services.

Therefore, on May 28, 2004, Devon 8 was retired. On May 28, 2004, a revised RMR agreement was filed with FERC for Devon 7 facility to account for the costs remaining after the retirement of Devon 8.

On June 2, 2004, FERC issued an order on ISO-NE's LICAP proposal. In the order, the FERC ruled that LICAP would not go into effect until January 1, 2006. In the order, FERC set for hearing the actual development of a LICAP proposal. In August 2004, ISO-NE filed its LICAP proposal with the administrative law judge who is presiding over our LICAP case. Until the implementation of LICAP, the existing PUSH bidding rules and existing RMR agreements would continue. New RMR agreements must also end when the LICAP market is implemented. In the order, FERC requested ISO-NE to address whether Southwest Connecticut (SWCT) should be in a separate energy and capacity zone. On July 7, 2004, ISO-NE filed a report with FERC requesting that a separate energy and capacity zone be created for SWCT as of January 1, 2006.

New York

In April of 2003, the 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. In a complaint filed with FERC on December 15, 2003, Consolidated Edison Company of New York, Inc. and other load-serving entities alleged that NYISO had used the wrong rate setting methodology to establish prices and rebates in the New York City markets for a portion of the summer capacity auction in 2003, and that this action resulted in overcharges to customers and overpayments to suppliers, including the Company, totaling approximately $21 million, with the Company's share being approximately $5 million. If the complaint were granted, the Company may be required to refund payments. On July 13, 2004, FERC denied the complaint.

12. Income Taxes

The Company is included in the consolidated tax return filings as a wholly owned indirect subsidiary of NRG Energy. Reflected in the financial statements and notes below are separate company federal and state tax provisions as if the Company had prepared separate filings. An income tax provision has been established on the accompanying consolidated financial statements as of the earliest period presented in order to reflect income taxes as if the Company filed its own tax return. The Company's ultimate parent, NRG Energy, does not have a tax allocation agreement with its subsidiaries and prior to January 1, 2003, income taxes were not recorded or allocated to non tax paying entities or entities such as the Company which are treated as disregarded entities for tax purposes. Because the Company is not a party to a tax sharing agreement, current tax expense (benefit) is recorded as a capital contribution from (distribution to) the Company's parent. The cumulative effect of recording an income tax provision (benefit) and deferred taxes resulted in recording as of December 31, 2002, a net deferred tax liability of $58.4 million and a reduction to members' equity of $58.4 million.

Income taxes for the six months ended June 30, 2004 was a tax expense of $57.4 million compared to a tax benefit of $135.6 million for the same period in 2003. The tax expense for the six months ended June 30, 2004 includes federal tax expense of $41.0 million and state tax expense of $16.4 million. The tax benefit for the same period in 2003 includes federal tax benefit of $96.9 million and state tax benefit of $38.7 million.

Income taxes for the three months ended June 30, 2004 was a tax expense of $24.4 million compared to a tax benefit of $123.0 million for the same period in 2003. The tax expense for the three months ended June 30, 2004 includes federal tax expense of $17.4 million and state tax expense of $7.0 million. The tax benefit for the same period in 2003 includes federal tax benefit of $87.9 million and state tax benefit of $35.1 million.

The effective income tax rate for the periods ended June 30, 2004 and 2003, differs from the statutory federal income tax rate of 35% due to state taxes.

As of June 30, 2004 and December 31, 2003, the Company had $84.8 million and $91.6 million, respectively, of noncurrent deferred tax assets attributable primarily to differences between book and tax basis of property and book reserves not currently deductible for tax purposes. A valuation allowance was not established against these deferred tax assets given the likelihood of realization.

EXHIBIT 99.3

INDIAN RIVER POWER LLC

FINANCIAL STATEMENTS

At June 30, 2004 and December 31, 2003, and for the Three and Six Months Ended June 30, 2004 and 2003

INDIAN RIVER POWER LLC

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INDIAN RIVER POWER LLC

BALANCE SHEETS

(Unaudited)

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
ASSETS		
Current assets		
Inventory	$ 9,816	$ 13,702
Prepayments and other current assets	237	1,171
Total current assets	10,053	14,873
Property, plant and equipment, net of accumulated depreciation of $9,573 and $1,080, respectively	391,720	395,021
Intangible assets, net of accumulated amortization of $1,527 and $0, respectively	56,004	57,531
Other assets	6,696	6,668
Total assets	$464,473	$ 474,093
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Accounts payable — trade	$ 10	$ 3
Accounts payable — affiliates	44,450	59,734
Accrued expenses	97	142
Deferred income tax	44	44
Other current liabilities	—	40
Total current liabilities	44,601	59,963
Deferred income tax	13,375	15,144
Other long-term obligations	4,391	4,256
Total liabilities	62,367	79,363
Commitments and contingencies		
Member's equity	402,106	394,730
Total liabilities and member's equity	$464,473	$ 474,093

The accompanying notes are an integral part of these financial statements.

INDIAN RIVER POWER LLC

STATEMENTS OF OPERATIONS

(Unaudited)

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended		Six Months Ended	
	June 30, 2004	June 30, 2003	June 30, 2004	June 30, 2003
	(In thousands of dollars)			
Revenues	**$ 34,871**	$ 24,616	**$ 76,428**	$ 68,285
Operating costs	**30,444**	19,678	**58,797**	46,969
Depreciation	**4,091**	5,718	**8,492**	11,690
General and administrative expenses	**1,955**	484	**3,573**	902
Income (loss) from operations	**(1,619)**	(1,264)	**5,566**	8,724
Interest expense	**—**	(3,974)	**—**	(7,839)
Other income, net	**14**	18	**41**	18
Income (loss) before income taxes	**(1,605)**	(5,220)	**5,607**	903
Income tax expense	**(654)**	(2,132)	**2,293**	369
Net income (loss)	**$ (951)**	$ (3,088)	**$ 3,314**	$ 534

The accompanying notes are an integral part of these financial statements.

INDIAN RIVER POWER LLC

STATEMENTS OF MEMBER'S EQUITY

For the Three Months Ended June 30, 2004 and 2003
(Unaudited)

	Member Units	Member Amount	Member Contributions/ Distributions	Accumulated Net Income (Loss)	Total Member's Equity
			(In thousands of dollars)		
Balances at March 31, 2003 (Predecessor Company)	1,000	$ 1	$ 193,522	$ 88,179	$281,702
Net loss and comprehensive loss				(3,088)	(3,088)
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 193,522	$ 85,091	$278,614
Balances at March 31, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 400,379**	**$ 2,703**	**$403,083**
Net loss and comprehensive loss				**(951)**	**(951)**
Distribution to member			**(26)**		**(26)**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 400,353**	**$ 1,752**	**$402,106**

The accompanying notes are an integral part of these financial statements.

INDIAN RIVER POWER LLC

STATEMENTS OF MEMBER'S EQUITY

For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Member		Member Contributions/ Distributions	Accumulated Net Income (Loss)	Total Member's Equity
	Units	Amount			
			(In thousands of dollars)		
Balances at December 31, 2002 (Predecessor Company)	1,000	$ 1	$ 193,522	$ 84,557	$278,080
Net income and comprehensive income				534	534
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 193,522	$ 85,091	$278,614
Balances at December 31, 2003 (Reorganized Company)	**1,000**	**$ 1**	**$ 396,291**	**$ (1,562)**	**$394,730**
Net income and comprehensive income				**3,314**	**3,314**
Contribution from member			**4,062**		**4,062**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 400,353**	**$ 1,752**	**$402,106**

The accompanying notes are an integral part of these financial statements.

INDIAN RIVER POWER LLC

STATEMENTS OF CASH FLOWS

(Unaudited)

	Reorganized Company	Predecessor Company
	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)	
Cash flows from operating activities		
Net income	**$ 3,314**	$ 534
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation	**8,492**	11,690
Amortization of intangibles	**1,527**	—
Amortization of debt issuance costs	**—**	668
Deferred income taxes	**(1,769)**	369
Current tax expense — noncash contribution from member	**4,062**	—
Changes in assets and liabilities		
Accounts receivable — affiliates	**—**	(3,611)
Inventory	**3,886**	4,050
Prepayments and other current assets	**934**	8,380
Other assets	**(28)**	(6,633)
Accounts payable — trade	**7**	6
Accounts payable — affiliates	**(15,284)**	(6,529)
Accrued expenses and other liabilities	**50**	519
Net cash provided by operating activities	**5,191**	9,443
Cash flows from investing activities		
Capital expenditures	**(5,191)**	(6,408)
Net cash used in investing activities	**(5,191)**	(6,408)
Cash flows from financing activities		
Payments on long-term borrowings	**—**	(2,007)
Bank overdraft	**—**	(1,028)
Net cash (used in) provided by financing activities	**—**	(3,035)
Net change in cash and cash equivalents	**—**	—
Cash and cash equivalents		
Beginning of period	**—**	—
End of period	**$ —**	$ —

The accompanying notes are an integral part of these financial statements.

INDIAN RIVER POWER LLC

NOTES TO FINANCIAL STATEMENTS

(Unaudited)

1. Organization

Indian River Power LLC (the "Company") is an indirect wholly owned subsidiary of NRG Energy, Inc. ("NRG Energy"). NRG MidAtlantic Generating LLC ("MidAtlantic Gen") owns 100% of the Company. MidAtlantic Gen's members are MidAtlantic Generation Holding LLC and NRG MidAtlantic LLC, both of which are wholly owned subsidiaries of NRG Energy and each of which owns a 50% interest in MidAtlantic Gen.

Recent Developments

On May 14, 2003, NRG Energy and 25 of its direct and indirect wholly owned subsidiaries commenced voluntary petitions under Chapter 11 of the bankruptcy code in the United States Bankruptcy Court for the Southern District of New York. During the bankruptcy proceedings, NRG Energy continued to conduct business and manage the companies as debtors in possession pursuant to sections 1107(a) and 1108 of the bankruptcy code. The Company was not part of these Chapter 11 cases or any of the subsequent bankruptcy filings. On November 24, 2003, the bankruptcy court entered an order confirming NRG Energy's Plan of Reorganization and the plan became effective on December 5, 2003. In connection with NRG Energy's emergence from bankruptcy, NRG Energy adopted fresh start accounting in accordance with AICPA Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code* ("SOP 90-7") on December 5, 2003. NRG Energy's fresh start accounting was applied to the Company on a push down accounting basis with the financial statement impact recorded as an adjustment to the December 6, 2003, member's equity.

2. Summary of Significant Accounting Policies

Basis of Presentation

As used in these unaudited interim financial statements, "Predecessor Company" refers to the Company prior to NRG Energy's emergence from bankruptcy. "Reorganized Company" refers to the Company after NRG Energy's emergence from bankruptcy.

The accompanying unaudited interim financial statements have been prepared in accordance with the Securities and Exchange Commission's or "SEC" regulations for interim financial information. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. The accounting policies followed are set forth in Note 2 to the Company's annual audited financial statements for the year ended December 31, 2003. The following notes should be read in conjunction with such policies and other disclosures. Interim results are not necessarily indicative of results for a full year.

In the opinion of management, the accompanying unaudited interim financial statements contain all material adjustments necessary to present fairly the Company's financial position as of June 30, 2004 and December 31, 2003, the results of its operations and member's equity for the three and six months ended June 30, 2004 and 2003 and cash flows for the six months ended June 30, 2004 and 2003. Certain prior-year amounts have been reclassified for comparative purposes.

Comparability of Financial Information

Due to NRG Energy's adoption of Fresh Start as of December 5, 2003, the Reorganized Company's balance sheet, statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are not comparable in certain respects to the financial statements prior to the application of push down accounting from NRG Energy's fresh start accounting. A black line has been drawn on the accompanying financial statements (excluding the balance sheet) to separate and distinguish between the Reorganized Company and the Predecessor Company.

3. Inventory

Inventory, which is valued at the lower of weighted average cost or market, consists of:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Fuel oil	$ 181	$ 378
Spare parts	3,538	3,557
Coal	6,097	9,767
Total inventory	$9,816	$ 13,702

4. Property, Plant and Equipment

The major classes of property, plant and equipment were as follows:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Land and improvements	$ 5,696	$ 5,696
Facilities and equipment	380,097	380,127
Office furnishings and equipment	233	203
Construction in progress	15,267	10,075
Total property, plant and equipment	401,293	396,101
Accumulated depreciation	(9,573)	(1,080)
Property, plant and equipment, net	$391,720	$ 395,021

5. Asset Retirement Obligation

Effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"). SFAS No. 143 requires an entity to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The Company identified an asset retirement obligation for future environmental obligations related to ash disposal site closure. The adoption of SFAS No. 143 resulted in recording a $1.4 million increase to property, plant and equipment and a $1.7 million increase to other long-term obligations. The cumulative effect of adopting SFAS No. 143 was recorded as a $0.2 million increase to depreciation expense and a $0.3 million increase to operating costs as the Company considered the cumulative effect to be immaterial.

The following represents the balances of the asset retirement obligation at January 1, 2004, and the accretion of the asset retirement obligation for the six months ended June 30, 2004, which is included in other long-term obligations in the Company's balance sheet.

	Reorganized Company		
	Beginning Balance January 1, 2004	Accretion for the Six Months Ended June 30, 2004	Ending Balance June 30, 2004
		(In thousands of dollars)	
Landfill closure obligation	$ 4,222	$ 145	$4,367

6. Intangible Assets

Upon the application of push down accounting, the Company established certain intangible assets for plant emission allowances. These intangible assets will be amortized over their respective lives based on units of production basis to resemble the Company's realization of such assets.

Emission allowances will be amortized as additional fuel expense based upon the actual level of emissions from the respective plants through 2023. Aggregate amortization recognized for the three and six months ended June 30, 2004, was approximately $0.4 million and $1.5 million, respectively. The annual aggregate amortization for each of the five succeeding years is expected to approximate $3.0 million each year.

Intangible assets consisted of the following:

	Emission Allowances
	(In thousands of dollars)
Original balance as of December 6, 2003	$ 57,531
Amortization	—
Balance as of December 31, 2003	57,531
Amortization	(1,527)
Balance as of June 30, 2004	$ 56,004

7. Commitments and Contingencies

Environmental Matters

The Company is responsible for the costs associated with closure, post-closure care and monitoring of the ash landfill owned and operated by the Company on the site of the Indian River Generating Station. No material liabilities outside such costs are expected. In accordance with certain regulations established by the Delaware Department of Natural Resources and Environmental Control, the Company has established a fully funded trust fund to provide for financial assurance for the closure and post-closure related costs in the amount of $6.7 million. The amounts contained in this fund will be dispersed as authorized by the Delaware Department of Natural Resources and Environmental Control. This amount is recorded in other noncurrent assets on the balance sheet.

Guarantees

In November 2002, the FASB issued FASB Interpretation No. ("FIN") 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* The initial recognition and initial measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year end. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. The interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. The interpretation also clarifies the requirements related to the recognition of a liability by a guarantor at the inception of the guarantee for the obligations the guarantor has undertaken in issuing the guarantee.

In connection with the application of push down accounting, all outstanding guarantees were considered new; accordingly, the Company applied the provisions of FIN 45 to all of those guarantees. Each guarantee was reviewed for the requirement to recognize a liability at inception.

On December 23, 2003, the Company is a guarantor under the debt issued by the Company's ultimate parent, NRG Energy. NRG Energy, issued $1.25 billion of 8% Second Priority Notes, due and payable on December 15, 2013. On January 28, 2004, NRG Energy also issued $475.0 million of Second Priority Notes, under the same terms and indenture as its December 23, 2003 offering.

NRG Energy's payment obligations under the notes and all related Parity Lien Obligations are guaranteed on an unconditional basis by each of NRG Energy's current and future restricted subsidiaries, of which the Company is one. The notes are jointly and severally guaranteed by each of the guarantors. The subsidiary guarantees of the notes are secured, on a second priority basis, equally and ratably with any future Parity Lien Debt, by security interests in all of the assets of the guarantors, except certain excluded assets, subject to liens securing parity lien debt and other permitted prior liens.

The Company's obligations pursuant to its guarantees of the performance, equity and indebtedness obligations were as follows:

	Guarantee/ Maximum Exposure	Nature of Guarantee	Expiration Date	Triggering Event
		(In thousands of dollars)		
NRG Energy Second Priority Notes due 2013	$1,753,000	Obligations under credit agreement	2013	Nonperformance

8. Regulatory Issues

On April 2, 2003, Reliant Resources, Inc. ("Reliant") filed a compliant against the Pennsylvania, Jersey, Maryland Interconnector area ("PJM") with FERC and suggested specific modifications to PJM's price mitigation rules. On June 9, 2003, FERC rejected the Reliant modifications but required PJM to file a report to address the concerns of Reliant by September 30, 2003. The PJM market monitoring unit filed its compliance filing with FERC as required, but opted to continue its present mitigation practices. The present mitigation plan permits PJM to "cost-cap" the energy bids of certain generating facilities that were constructed prior to 1996. The cost capping method is based on a facility's variable costs plus 10%. In addition, the PJM market monitoring unit filed to eliminate the exemption that units built after 1996 had from PJM's mitigation measures. On May 6, 2004, FERC rejected the proposed extension of the cost capping mechanism to generating facilities built after 1996. In the order, the FERC approved the application of cost-capping mitigation method for facilities built prior to 1996 and were cost capped less than 80% of the time the facilities operated. The FERC required that for facilities that are cost capped 80% or more of their operating hours mitigated, are needed for reliability and are not recovering sufficient revenue to cover their costs, that PJM must provide alternative methods of compensation. The FERC noted that such alternative compensation could consist of market design changes such as a higher bid cap or reliability must run agreements. FERC required that PJM file such a proposal by November 6, 2004. At this time it is unclear how this ruling will impact the Company. The Company continues to monitor these activities for any potential adverse impact to the Company's financial position or results of operations.

9. Income Taxes

The Company is included in the consolidated tax return filings as a wholly owned indirect subsidiary of NRG Energy. Reflected in the financial statements and notes below are separate company federal and state tax provisions as if the Company had prepared separate filings. An income tax provision has been established on the accompanying financial statements as of the earliest period presented in order to reflect income taxes as if the Company filed its own tax return. The Company's ultimate parent, NRG Energy, does not have a tax allocation agreement with its subsidiaries nor has it historically pushed down or allocated income taxes to non tax paying entities or entities such as the Company which are treated as disregarded entities for tax purposes. Because the Company is not a party to a tax sharing agreement, current tax expense (benefit) is recorded as a capital contribution from (distribution to) the Company's parent. The cumulative effect of recording an income tax provision (benefit) and deferred taxes resulting in recording as of December 31, 2002, a net deferred tax liability of $98.9 million and a reduction to member's equity of $98.9 million.

Income taxes for the six months ended June 30, 2004 was a tax expense of $2.3 million compared to a tax expense of $0.4 million for the same period in 2003. The tax expense for the six months ended June 30, 2004 includes federal tax expense of $1.8 million and state tax expense of $0.5 million. The tax expense for the same period in 2003 includes federal tax expense of $0.3 million and state tax expense of $0.1 million.

Income taxes for the three months ended June 30, 2004 was a tax benefit of $0.7 million compared to a tax benefit of $2.1 million for the same period in 2003. The tax benefit for the three months ended June 30, 2004 includes federal tax benefit of $0.5 million and state tax benefit of $0.2 million. The tax benefit for the same period in 2003 includes tax benefit of $1.6 million and state tax benefit of $0.5 million.

The effective income tax rate for the periods ended June 30, 2004 and 2003, differs from the statutory federal income tax rate of 35% due to state taxes.

As of June 30, 2004 and December 31, 2003, the Company had $13.4 million and $15.1 million, respectively, of noncurrent deferred tax liabilities attributable primarily to differences between book and tax basis of property and emissions credits.

EXHIBIT 99.4

NRG MIDATLANTIC GENERATING LLC

CONSOLIDATED FINANCIAL STATEMENTS

At June 30, 2004 and December 31, 2003, and for the Three and Six Months Ended June 30, 2004 and 2003

NRG MIDATLANTIC GENERATING LLC

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NRG MIDATLANTIC GENERATING LLC

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	Reorganized Company	
	June 30, 2004	**December 31, 2003**
ASSETS		
Current assets		
Cash and cash equivalents	$ 32,423	$ 77
Accounts receivable — affiliates	—	5,155
Inventory	13,484	17,611
Derivative instruments valuation	214	161
Prepayments and other current assets	507	2,385
Total current assets	46,628	25,389
Property, plant and equipment, net of accumulated depreciation of $14,536 and $1,693, respectively	558,200	565,201
Investment in projects	1,280	1,280
Intangible assets, net of accumulated amortization of $2,154 and $0, respectively	66,315	68,469
Other assets	6,813	6,753
Total assets	$679,236	$ 667,092
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities		
Accounts payable — trade	$ 10	$ 38
Accounts payable — affiliates	2,030	259
Accrued expenses	97	142
Derivative instruments valuation	—	163
Deferred income tax	56	56
Other current liabilities	—	285
Total current liabilities	2,193	943
Deferred income tax	32,853	32,979
Other long-term obligations	4,391	4,256
Total liabilities	39,437	38,178
Commitments and contingencies		
Members' equity	639,799	628,914
Total liabilities and members' equity	$679,236	$ 667,092

The accompanying notes are an integral part of these consolidated financial statements.

NRG MIDATLANTIC GENERATING LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended		Six Months Ended	
	June 30, 2004	June 30, 2003	June 30, 2004	June 30, 2003
		(In thousands of dollars)		
Revenues	**$ 45,482**	$ 33,163	**$ 99,898**	$ 91,862
Operating costs	**36,307**	25,153	**70,773**	64,200
Depreciation	**6,272**	7,335	**12,843**	14,997
General and administrative expenses	**3,234**	740	**5,818**	1,525
Restructuring charges	**—**	1,237	**—**	1,237
Income (loss) from operations	**(331)**	(1,302)	**10,464**	9,903
Interest expense	**—**	(5,212)	**—**	(10,265)
Other income, net	**14**	301	**81**	569
Income (loss) before income taxes	**(317)**	(6,213)	**10,545**	207
Income tax expense (benefit)	**(127)**	(2,524)	**4,287**	84
Net income (loss)	**$ (190)**	$ (3,689)	**$ 6,258**	$ 123

The accompanying notes are an integral part of these consolidated financial statements.

NRG MIDATLANTIC GENERATING LLC

CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY

For the Three Months Ended June 30, 2003 and 2004
(Unaudited)

	Members' Unit	Members' Amount	Members' Contributions/ Distributions	Accumulated Net Income (Loss)	Accumulated Other Comprehensive Income	Total Members' Equity
			(In thousands of dollars)			
Balances at March 31, 2003 (Predecessor Company)	1,000	$ 1	$ 190,725	$ 92,285	$ —	$283,011
Net loss				(3,689)		(3,689)
Comprehensive loss						(3,689)
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 190,725	$ 88,596	$ —	$279,322
Balances at March 31, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 633,680**	**$ 4,975**	**$ —**	**$638,656**
Net loss				**(190)**		**(190)**
Impact of SFAS No. 133 for the three months ended June 30, 2004					**214**	**214**
Comprehensive income						**24**
Contribution from members			**1,119**			**1,119**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 634,799**	**$ 4,785**	**$ 214**	**$639,799**

The accompanying notes are an integral part of these consolidated financial statements.

NRG MIDATLANTIC GENERATING LLC

CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY

For the Six Months Ended June 30, 2003 and 2004
(Unaudited)

	Members' Unit	Members' Amount	Members' Contributions/ Distributions	Accumulated Net Income (Loss)	Accumulated Other Comprehensive Income	Total Members' Equity
			(In thousands of dollars)			
Balances at December 31, 2002 (Predecessor Company)	1,000	$ 1	$ 190,725	$ 88,473	$ —	$279,199
Net income				123		123
Comprehensive income						123
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 190,725	$ 88,596	$ —	$279,322
Balances at December 31, 2003 (Reorganized Company)	**1,000**	**$ 1**	**$ 630,386**	**$ (1,473)**	**$ —**	**$628,914**
Net income				**6,258**		**6,258**
Impact of SFAS No. 133 for the six months ended June 30, 2004					**214**	**214**
Comprehensive income						**6,472**
Contribution from members			**4,413**			**4,413**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 634,799**	**$ 4,785**	**$ 214**	**$639,799**

The accompanying notes are an integral part of these consolidated financial statements.

NRG MIDATLANTIC GENERATING LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Reorganized Company	Predecessor Company
	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)	
Cash flow from operating activities		
Net income	**$ 6,258**	$ 123
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation	**12,843**	14,997
Unrealized (gain) loss on derivatives	**(2)**	4,114
Amortization of debt issuance costs	**—**	864
Amortization of intangible assets	**2,154**	—
Deferred income taxes	**(126)**	84
Current tax expense — non cash contribution from members	**4,413**	—
Changes in assets and liabilities		
Accounts receivable, net	**—**	(1,120)
Accounts receivable — affiliates	**5,155**	—
Inventory	**4,127**	3,653
Prepayments and other current assets	**1,878**	11,003
Other assets	**(60)**	(6,633)
Accounts payable — trade	**(28)**	(425)
Accounts payable — affiliates	**1,771**	(10,950)
Accrued interest	**—**	(7)
Changes in other liabilities	**(195)**	916
Net cash provided by operating activities	**38,188**	16,619
Cash flows from investing activities		
Increase in restricted cash	**—**	(5,515)
Capital expenditures	**(5,842)**	(8,463)
Net cash used in investing activities	**(5,842)**	(13,978)
Cash flows from financing activities		
Payments on long-term borrowings	**—**	(2,641)
Net cash used in financing activities	**—**	(2,641)
Net change in cash and cash equivalents	**32,346**	—
Cash and cash equivalents		
Beginning of period	**77**	—
End of period	**$ 32,423**	$ —

The accompanying notes are an integral part of these consolidated financial statements.

NRG MIDATLANTIC GENERATING LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Organization

NRG Mid Atlantic Generating LLC (the “Company”), a wholly owned indirect subsidiary of NRG Energy, Inc. (“NRG Energy”), owns electric power generation plants in the mid-atlantic region of the United States. The Company’s members are MidAtlantic Generation Holding LLC (“MidAtlantic Generation”) and NRG MidAtlantic LLC (“NRG MidAtlantic”) each of which owns a 50% interest in the Company and are directly held wholly owned subsidiaries of NRG Energy.

The Company was formed in May, 2000 for the purpose of financing, acquiring, owning, operating and maintaining, through its subsidiaries the power generation facilities owned by Indian River Power LLC (“Indian River”), Vienna Power LLC (“Vienna”), Keystone Power LLC (“Keystone”) and Conemaugh Power LLC (“Conemaugh”).

Recent Developments

On May 14, 2003, NRG Energy and 25 of its direct and indirect wholly owned subsidiaries commenced voluntary petitions under Chapter 11 of the bankruptcy code in the United States Bankruptcy Court for the Southern District of New York. During the bankruptcy proceedings, NRG Energy continued to conduct business and manage the companies as debtors in possession pursuant to sections 1107(a) and 1108 of the bankruptcy code. The Company was not part of these Chapter 11 cases or any of the subsequent bankruptcy filings. On November 24, 2003, the bankruptcy court entered an order confirming NRG Energy’s Plan of Reorganization and the plan became effective on December 5, 2003. In connection with NRG Energy’s emergence from bankruptcy, NRG Energy adopted fresh start accounting in accordance with AICPA Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code* (“SOP 90-7”) on December 5, 2003. NRG Energy’s fresh start accounting was applied to the Company on a push down accounting basis with the financial statement impact recorded as an adjustment to the December 6, 2003, members’ equity.

2. Summary of Significant Accounting Policies

Basis of Presentation

As used in these unaudited interim consolidated financial statements, “Predecessor Company” refers to the Company prior to NRG Energy’s emergence from bankruptcy. “Reorganized Company” refers to the Company after NRG Energy’s emergence from bankruptcy.

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with the Securities and Exchange Commission’s or “SEC” regulations for interim consolidated financial information. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. The accounting policies followed are set forth in Note 2 to the Company’s annual consolidated audited financial statements for the year ended December 31, 2003. The following notes should be read in conjunction with such policies and other disclosures. 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 necessary to present fairly the Company’s consolidated financial position as of June 30, 2004 and December 31, 2003, the results of its operations and members’ equity for the three and six months ended June 30, 2004 and 2003 and cash flows for the six months ended June 30, 2004 and 2003. Certain prior-year amounts have been reclassified for comparative purposes.

Comparability of Financial Information

Due to NRG Energy's adoption of Fresh Start as of December 5, 2003, the Reorganized Company's consolidated balance sheet, statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are not comparable in certain respects to the financial statements prior to the application of push down accounting from NRG Energy's fresh start accounting. A black line has been drawn on the accompanying consolidated financial statements (excluding the balance sheet) to separate and distinguish between the Reorganized Company and the Predecessor Company.

3. Inventory

Inventory, which is valued at the lower of weighted average cost or market, consists of:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Fuel oil	$ 2,210	$ 2,601
Spare parts	5,116	5,188
Coal	6,158	9,822
Total inventory	$13,484	$ 17,611

4. Property, Plant and Equipment

The major classes of property, plant and equipment were as follows:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Land	$ 19,386	$ 19,386
Facilities and equipment	537,592	536,925
Construction work in progress	15,758	10,583
Total property, plant and equipment	572,736	566,894
Accumulated depreciation	(14,536)	(1,693)
Property, plant and equipment, net	$558,200	$ 565,201

5. Asset Retirement Obligation

Effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards SFAS No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"). SFAS No. 143 requires an entity to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The Company identified an asset retirement obligation related to environmental obligations related to ash disposal site closure. The adoption of SFAS No. 143 resulted in recording a $1.4 million increase to property, plant and equipment and a $1.7 million increase to other long-term obligations. The cumulative effect of adopting SFAS No. 143 was recorded as a $0.2 million increase to depreciation expense and a $0.3 million increase to operating costs, as the Company considered the cumulative effect to be immaterial.

The following represents the balances of the asset retirement obligation at January 1, 2004, and the accretion of the asset retirement obligation for the six months ended June 30, 2004, which is included in other long-term obligations in the consolidated balance sheets.

	Reorganized Company		
	Beginning Balance January 1, 2004	Accretion for the Six Months Ended June 30, 2004	Ending Balance June 30, 2004
		(In thousands of dollars)	
Indian River landfill closure obligation	$ 4,222	$ 145	$4,367

6. Intangible Assets

Upon the application of push down accounting, the Company established certain intangible assets for plant emission allowances. These intangible assets will be amortized over their respective lives based on a units of production basis to resemble the Company's realization of such assets.

Emission allowances will be amortized as additional fuel expense based upon the actual level of emissions from the respective plants through 2023. Aggregate amortization recognized for the three and six months ended June 30, 2004, was approximately $0.8 million and $2.2 million, respectively. The annual aggregate amortization for each of the five succeeding years is expected to approximate $4.0 million each year.

Intangible assets consisted of the following:

	Emission Allowances
	(In thousands of dollars)
Original balance as of December 6, 2003	$ 68,469
Amortization	—
Balance as of December 31, 2003	68,469
Amortization	(2,154)
Balance as of June 30, 2004	$ 66,315

7. Investments Accounted for by the Cost Method

The Company had investments of $1.3 million in two joint venture projects, Keystone Fuels LLC ("Keystone") (3.70%) and Conemaugh Fuels LLC ("Conemaugh") (3.72%), that were formed for the purpose of buying coal and selling such coal to Keystone and Conemaugh, or to any entity that manufacturers or produces synthetic fuel from coal for resale to Keystone or Conemaugh. The cost method of accounting is applied to such investments because the ownership structure prevents the Company from exercising a controlling influence over operating and financial policies of the projects.

8. Derivative Instruments and Hedging Activity

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133), as amended, requires the Company to record all derivatives on the consolidated balance sheet as assets or liabilities at fair value. For derivatives designated as cash flow hedges, the effective portion of the changes in fair value of the derivatives are recorded in accumulated other comprehensive income (“OCI”) and subsequently recognized in earnings when the hedged items impact 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. Changes in the fair value of nonhedge derivatives will be immediately recognized in earnings. Additionally, many of the Company’s commodity sales and purchase agreements that otherwise would be required to follow derivative accounting qualify as normal purchases and sales under SFAS No. 133 and are therefore exempt from fair value accounting.

SFAS No. 133 applies to the Company’s long-term power sales contracts, long-term fuel purchase contracts and other energy related commodities financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect investments in fuel inventories. At June 30, 2004, the Company had various commodity contracts extending through December 2005. Certain of these contracts meet the hedge accounting requirements of SFAS No. 133, and are designated as cash flow hedges.

The adoption of SFAS No. 133 on January 1, 2001, resulted in no amounts being recorded on the consolidated balance sheet as the Company had no derivatives at January 1, 2001. The Company has derivatives accounted for as hedges at June 30, 2004, and for the three and six months ended June 30, 2004. The Company had no derivatives accounted for as hedges at December 31, 2003 or for the three and six months ended June 30, 2003.

Accumulated Other Comprehensive Income

The following table summarizes the effects of SFAS No. 133 on the Company’s OCI balance attributable to hedged derivatives:

	Reorganized Company Three Months Ended June 30, 2004	Reorganized Company Six Months Ended June 30, 2004
Gains/(Losses)		
Beginning balance	$ —	$ —
Unwound from OCI during period due to unwinding of previously deferred amounts	—	—
Mark to market hedge contracts	214	214
Ending balance	$ 214	$ 214
Gains expected to unwind from OCI during next 12 months	$ 214	$ 214

During the three and six months ended June 30, 2004 the Company recorded gains in OCI of $0.2 million, related to changes in the fair values of derivatives accounted for as hedges.

The net balance in OCI relating to OCI as of June 30, 2004 was an unrecognized gain of $0.2 million. The Company expects $0.2 million of deferred net losses on derivative instruments accumulated in OCI to be recognized in earnings during the next 12 months.

Statement of Operations

The following table summarizes the pre-tax effects of nonhedge derivatives on the Company's statements of operations:

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)			
Gains (Losses)				
Revenues	**$ (217)**	$ (359)	**$ 2**	$ (1,216)
Costs of operations	**—**	—	**—**	(2,898)
Total statement of operations impact before tax	**$ (217)**	$ (359)	**$ 2**	$ (4,114)

Energy Related Commodities

The Company is exposed to commodity price variability in electricity, emission allowances and natural gas, oil and coal used to meet fuel requirements. In order to manage these commodity price risks, the Company enters into financial instruments, which may take the form of fixed price, floating price or indexed sales or purchases, and options, such as puts, calls, basis transactions and swaps. The Company has accounted for these derivatives by recording the derivative at market value with the offset being charged to earnings.

The Company's earnings for the three months ended June 30, 2004, were decreased by an unrealized loss of $0.2 million and for the six months ended June 30, 2004 earnings were increased by an unrealized gain of $2,000, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

The Company's earnings for the three and six months ended June 30, 2003, were decreased by an unrealized loss of $0.4 million and $4.1 million, respectively associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

9. Commitments and Contingencies

Environmental Matters

The Company's subsidiary, Indian River, is responsible for the costs associated with closure, post-closure care and monitoring of the ash landfill owned and operated by the Company on the site of the Indian River Generating Station. No material liabilities outside such costs are expected. In accordance with certain regulations established by the Delaware Department of Natural Resources and Environmental Control, the Company has established a fully funded trust fund to provide for financial assurance for the closure and post-closure related costs in the amount of $6.7 million. The amounts contained in this fund will be dispersed as authorized by the Delaware Department of Natural Resources and Environmental Control. This amount is recorded in other noncurrent assets on the consolidated balance sheet.

Guarantees

In November 2002, the FASB issued FASB Interpretation No. ("FIN") 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* The initial recognition and initial measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year end. The disclosure requirements are effective for financial statements of interim or annual periods ending after

December 15, 2002. The interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. The interpretation also clarifies the requirements related to the recognition of a liability by a guarantor at the inceptions of the guarantee for the obligations the guarantor has undertaken in issuing the guarantee.

In connection with the application of push down accounting, all outstanding guarantees were considered new; accordingly, the Company applied the provisions of FIN 45 to all of those guarantees. Each guarantee was reviewed for the requirement to recognize a liability at inceptions.

The Company is a guarantor under the debt issued by the Company's ultimate parent, NRG Energy. On December 23, 2003, NRG Energy issued $1.25 billion of 8% Second Priority Notes, due and payable on December 15, 2013. On January 28, 2004, NRG Energy also issued $475.0 million of Second Priority Notes, under the same terms and indenture as its December 23, 2003 offering.

NRG Energy's payment obligations under the notes and all related Parity Lien Obligations are guaranteed on an unconditional basis by each of NRG Energy's current and future restricted subsidiaries, of which the Company is one. The notes are jointly and severally guaranteed by each of the guarantors. The subsidiary guarantees of the notes are secured, on a second priority basis, equally and ratably with any future parity lien debt, by security interest in all of the assets of the guarantors, except certain excluded assets, subject to liens securing parity lien debt and other permitted prior liens.

The Company's obligations pursuant to its guarantees of the performance, equity and indebtedness obligations were as follows:

	Guarantee/ Maximum Exposure	Nature of Guarantee	Expiration Date	Triggering Event
	(In thousands of dollars)			
NRG Energy Second Priority Notes due 2013	$1,753,000	Obligations under credit agreement	2013	Nonperformance

10. Regulatory Issues

PJM

On April 2, 2003, Reliant Resources, Inc. ("Reliant") filed a compliant against the Pennsylvania, Jersey, Maryland Interconnector area ("PJM") with FERC and suggested specific modifications to PJM's price mitigation rules. On June 9, 2003, FERC rejected the Reliant modifications but required PJM to file a report to address the concerns of Reliant by September 30, 2003. The PJM market monitoring unit filed its compliance filing with FERC as required, but opted to continue its present mitigation practices. The present mitigation plan permits PJM to "cost-cap" the energy bids of certain generating facilities that were constructed prior to 1996. The cost capping method is based on a facility's variable costs plus 10%. In addition, the PJM market monitoring unit filed to eliminate the exemption that units built after 1996 had from PJM's mitigation measures. On May 6, 2004, FERC rejected the proposed extension of the cost capping mechanism to generating facilities built after 1996. In the order, the FERC approved the application of cost-capping mitigation method for facilities built prior to 1996 and were cost capped less than 80% of the time the facilities operated. The FERC required that for facilities that are cost capped 80% or more of their operating hours mitigated, are needed for reliability and are not recovering sufficient revenue to cover their costs, that PJM must provide alternative methods of compensation. The FERC noted that such alternative compensation could consist of market design changes such as a higher bid cap or reliability must run agreements. FERC required that PJM file such a proposal by November 6, 2004. At this time it is unclear how this ruling will impact the Company. The Company continues to monitor these activities for any potential adverse impact to the Company's financial position or results of operations.

PJM — West

On December 31, 2003 and February 5, 2004, PJM filed proposed mitigation plans for the Commonwealth Edison, or Com Ed, franchise territory. Among the proposed changes was the adoption of the existing PJM energy market mitigation plan of “cost capping” and a new mitigation plan for the capacity market. PJM proposed that the proposed energy market mitigation plan would only be effective through the 2004 summer season but that the capacity mitigation plan would remain effective until April 1, 2005. Under the capacity mitigation proposal, capacity prices would be capped at $30 per MW-day except when capacity levels are less than 101% of required reserves, then the price cap would be $160 per MW-day. On March 24, 2004, FERC rejected the proposed mitigation plans. On April 23, 2004, PJM filed a rehearing request on the rejection of the capacity market mitigation proposal. In the rehearing request, PJM requested that the $30 per MW-day cap be approved and that during times of scarcity there would not be a price cap. FERC has not yet issued an order on the rehearing request.

11. Income Taxes

The Company is included in the consolidated tax return filings as a wholly owned indirect subsidiary of NRG Energy. Reflected in the financial statements and notes below are separate company federal and state tax provisions as if the Company had prepared separate filings. An income tax provision has been established on the accompanying consolidated financial statements as of the earliest period presented in order to reflect income taxes as if the Company filed its own tax return. The Company’s ultimate parent, NRG Energy, does not have a tax allocation agreement with its subsidiaries and prior to January 1, 2003, income taxes were not recorded or allocated to non tax paying entities or entities such as the Company which are treated as disregarded entities for tax purposes. Because the Company is not a party to a tax sharing agreement, current tax benefit (expense) is recorded as a capital contribution from (distribution to) the Company’s parent. The cumulative effect of recording an income tax provision (benefit) and deferred taxes resulting in recording as of December 31, 2002, a net deferred tax liability of $99.7 million and a reduction to members’ equity of $99.7 million.

Income taxes for the six months ended June 30, 2004 was a tax expense of $4.3 million compared to a tax expense of $.08 million for the same period in 2003. The tax expense for the six months ended June 30, 2004 includes federal tax expense of $3.4 million and state tax expense of $0.9 million. The tax expense for the same period in 2003 includes federal tax expense of $.06 million and state tax expense of $.02 million.

Income taxes for the three months ended June 30, 2004 was a tax benefit of $0.1 million compared to a tax benefit of $2.5 million for the same period in 2003. The tax benefit for the three months ended June 30, 2004 includes federal tax benefit of $0.1 million and state tax benefit of $0.0 million. The tax benefit for the same period in 2003 includes federal tax benefit of $2.0 million and state tax benefit of $.5 million.

The effective income tax rate for the period ended June 30, 2004 and 2003, differs from the statutory federal income tax rate of 35% due to state taxes.

As of June 30, 2004 and December 31, 2003, the Company had $32.9 million and $33.0 million, respectively of noncurrent deferred tax liabilities attributable primarily to differences between book and tax basis of property and emissions credits.

EXHIBIT 99.5

NRG SOUTH CENTRAL GENERATING LLC

CONSOLIDATED FINANCIAL STATEMENTS

At June 30, 2004 and December 31, 2003, and for
the Three and Six Months Ended June 30, 2004 and 2003

NRG SOUTH CENTRAL GENERATING LLC

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NRG SOUTH CENTRAL GENERATING LLC

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 50,685	$ 4,612
Restricted cash	—	99
Accounts receivable	33,333	37,080
Accounts receivable — affiliates	—	3,328
Notes receivable	—	584
Inventory	29,797	35,098
Prepayments and other current assets	4,502	7,079
Total current assets	118,317	87,880
Property, plant and equipment, net of accumulated depreciation of $34,094 and $2,561, respectively	908,672	914,941
Decommissioning fund investments	4,916	4,809
Intangible assets, net of amortization of $7,314 and $787, respectively	104,290	120,992
Other assets	1,627	3,111
Total assets	$1,137,822	$1,131,733
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities		
Current notes payable — affiliate	$ 1,002	$ 81,673
Accounts payable	4,949	10,476
Accounts payable — affiliates	4,171	—
Accrued interest — affiliates	10,865	7,434
Derivative instruments valuation	115	73
Other current liabilities	15,240	18,452
Total current liabilities	36,342	118,108
Notes payable — affiliate	79,297	—
Burdensome contracts	330,133	341,004
Other long-term obligations	10,972	9,789
Total liabilities	456,744	468,901
Commitments and contingencies		
Members' equity	681,078	662,832
Total liabilities and members' equity	$1,137,822	$1,131,733

The accompanying notes are an integral part of these consolidated financial statements.

NRG SOUTH CENTRAL GENERATING LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended		Six Months Ended	
	June 30, 2004	June 30, 2003	June 30, 2004	June 30, 2003
	(In thousands of dollars)			
Revenues	**$ 102,497**	$ 92,618	**$ 197,762**	$ 196,508
Operating costs	**62,649**	59,796	**122,244**	122,245
Depreciation and amortization	**14,572**	10,006	**31,534**	18,951
General and administrative expenses	**5,897**	2,769	**10,238**	6,094
Reorganization items	**(69)**	—	**654**	—
Restructuring and impairment charges	**1,676**	2,135	**1,676**	2,804
Income from operations	**17,772**	17,912	**31,416**	46,414
Other income, net	**17**	546	**102**	934
Interest expense	**(1,296)**	(19,547)	**(3,646)**	(38,489)
Income (loss) before income taxes	**16,493**	(1,089)	**27,872**	8,859
Income tax expense	**5,596**	—	**10,175**	—
Net income (loss)	**$ 10,897**	$ (1,089)	**$ 17,697**	$ 8,859

The accompanying notes are an integral part of these consolidated financial statements.

NRG SOUTH CENTRAL GENERATING LLC

CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY

Three Months Ended June 30, 2004 and 2003
(Unaudited)

	Members' Units	Members' Amount	Members' Contributions/ Distributions	Accumulated Net Income (Loss)	Total Members' Equity
			(In thousands of dollars)		
Balances at March 31, 2003 (Predecessor Company)	1,000	$ 1	$ 434,161	$ (100,564)	$333,598
Net loss and comprehensive loss	—	—	—	(1,089)	(1,089)
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 434,161	$ (101,653)	$332,509
Balances at March 31, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 662,538**	**$ 7,093**	**$669,632**
Contribution from members	**—**	**—**	**549**	**—**	**549**
Net income and comprehensive income	**—**	**—**	**—**	**10,897**	**10,897**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 663,087**	**$ 17,990**	**$681,078**

The accompanying notes are an integral part of these consolidated financial statements.

NRG SOUTH CENTRAL GENERATING LLC

CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY

Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Members'		Members' Contributions/ Distributions	Accumulated Net Income (Loss)	Total Members' Equity
	Units	Amount			
			(In thousands of dollars)		
Balances at December 31, 2002 (Predecessor Company)	1,000	$ 1	$ 434,161	$ (110,512)	$323,650
Net income and comprehensive income	—	—	—	8,859	8,859
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 434,161	$ (101,653)	$332,509
Balances at December 31, 2003 (Reorganized Company)	**1,000**	**$ 1**	**$ 662,538**	**$ 293**	**$662,832**
Contribution from members	**—**	**—**	**549**	**—**	**549**
Net income and comprehensive income	**—**	**—**	**—**	**17,697**	**17,697**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 663,087**	**$ 17,990**	**$681,078**

The accompanying notes are an integral part of these consolidated financial statements.

NRG SOUTH CENTRAL GENERATING LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Reorganized Company	Predecessor Company
	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)	
Cash flows from operating activities		
Net income	**$ 17,697**	$ 8,859
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	**31,533**	18,951
Amortization of out-of-market power contracts	**(10,871)**	—
Amortization of intangibles	**6,527**	—
Impairment charges	**1,676**	—
Amortization of debt discount	**1,265**	—
Amortization of debt issuance costs	**—**	837
Unrealized (gain) loss on derivatives	**42**	(423)
Deferred income taxes	**10,175**	—
Changes in assets and liabilities		
Accounts receivable	**3,747**	15,621
Inventory	**5,301**	4,006
Prepayments and other current assets	**2,577**	(4,407)
Accounts payable	**(5,527)**	12,634
Accounts payable and receivable — affiliates	**7,499**	1,307
Accrued interest — affiliates	**3,431**	(32,528)
Accrued fuel and purchase power expense	**—**	(7,501)
Other current liabilities	**(3,212)**	(3,798)
Changes in other assets and liabilities	**2,560**	(63)
Net cash provided by operating activities	**74,420**	13,495
Cash flows from investing activities		
Capital expenditures	**(26,940)**	(5,389)
Decrease in notes receivable	**584**	1,500
(Increase)/decrease in restricted cash	**99**	(1,917)
Net cash used in investing activities	**(26,257)**	(5,806)
Cash flows from financing activities		
Contribution by members	**549**	—
Payment of intercompany loan	**(2,639)**	—
Checks in excess of cash	**—**	42
Net cash provided by (used in) financing activities	**(2,090)**	42
Net change in cash and cash equivalents	**46,073**	7,731
Cash and cash equivalents		
Beginning of period	**4,612**	310
End of period	**$ 50,685**	$ 8,041

The accompanying notes are an integral part of these consolidated financial statements.

NRG SOUTH CENTRAL GENERATING LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Organization

NRG South Central Generating LLC ("NRG South Central" or the "Company") was formed in 2000 and is an indirect wholly owned subsidiary of NRG Energy, Inc. ("NRG Energy"). NRG South Central owns 100% of Louisiana Generating LLC ("Louisiana Generating"), NRG New Roads Holding LLC ("New Roads"), NRG Sterlington Power LLC ("Sterlington"), Big Cajun I Peaking Power LLC ("Big Cajun Peaking") and NRG Bayou Cove LLC ("Bayou Cove"). NRG South Central's members are NRG Central U.S. LLC ("NRG Central") and South Central Generation Holding LLC ("South Central Generation"). NRG Central and South Central Generation are directly held wholly owned subsidiaries of NRG Energy, each of which owns a 50% interest in NRG South Central.

NRG South Central was formed for the purpose of financing, acquiring, owning, operating and maintaining through its subsidiaries and affiliates the facilities owned by Louisiana Generating and any other facilities that it or its subsidiaries may acquire in the future.

Pursuant to a competitive bidding process, following the Chapter 11 bankruptcy proceeding of Cajun Electric Power Cooperative, Inc. ("Cajun Electric"), Louisiana Generating acquired the non-nuclear electric power generating assets of Cajun Electric. New Roads was formed for the purpose of holding assets that Louisiana Generating acquired from Cajun Electric which are not necessary for the operation of the newly acquired generating facilities and, with respect to some of these assets, may not be held by Louisiana Generating under applicable federal regulations. Sterlington, which was acquired by NRG Energy and contributed to NRG South Central in August 2000, was formed for the purpose of developing, constructing, owning, and operating an approximately 200 MW simple cycle gas peaking facility in Sterlington, Louisiana. Louisiana Generating purchases the capacity and is entitled to all energy from Sterlington. Big Cajun Peaking was formed to develop, construct and own a 238 MW gas-fired peaking generating facility located in New Roads, Louisiana. Bayou Cove was formed to develop, construct and own a 320 MW gas-fired peaking generating facility located in Jennings, Louisiana. Bayou Cove is operated as a merchant power facility.

On March 31, 2000, for approximately $1,055.9 million, Louisiana Generating acquired 1,708 MW of electric power generation facilities located in New Roads, Louisiana ("Cajun facilities"). The acquisition was financed through a combination of project level long-term debt issued by NRG South Central and equity contributions from NRG South Central's members. Prior to December 23, 2003, Louisiana Generating was a guarantor of the bonds issued on March 30, 2000, to acquire the Cajun facilities. The acquisition was accounted for under the purchase method of accounting with the aggregate purchase price allocated among the acquired assets and liabilities assumed.

Pursuant to a project development agreement between NRG Energy and Koch Power, Inc., NRG Energy agreed in April 1999 to participate in the development of an approximately 200 MW simple cycle gas peaking facility in Sterlington, Louisiana. Development of the facility had been commenced by Koch Power's affiliate, Koch Power Louisiana LLC, a Delaware limited liability company. In August 2000, NRG Energy acquired 100% of Koch Power Louisiana from Koch Power, and renamed it NRG Sterlington Power LLC and contributed the subsidiary to NRG South Central. In August, 2001, the facility became commercially operational.

Big Cajun I Peaking Power LLC was formed in July 2000 for the purpose of developing, owning and operating an approximately 238 MW simple cycle natural gas peaking facility expansion project at the Big Cajun I site in New Roads, Louisiana. The peaking facility was completed in June 2001. The energy and capacity generated by the expansion project is used to help meet Louisiana Generating's obligations under the Cajun facilities' power purchase agreements, with any excess power and capacity being marketed by NRG Power Marketing.

During November 2000, NRG Energy acquired a 49% limited partnership interest and a 1% general partnership interest in SRW Cogeneration Limited Partnership ("SRW Cogeneration") for $15 million and contributed the partnership interests to NRG Sabine River Works LP LLC and NRG Sabine River Works GP LLC, Delaware limited liability companies wholly owned by NRG South Central. SRW Cogeneration completed the facility which became commercially operational in November 2001. The approximately 450 MW natural gas-fired cogeneration plant is located at the DuPont Company's Sabine River Works petrochemical facility near Orange, Texas. Subsidiaries of Conoco, Inc. own the other 49% and 1% general partnership interests in SRW Cogeneration. On November 5, 2002, the investment in SRW Cogeneration was sold to Conoco, Inc for a nominal value and the assumption of certain outstanding obligations.

NRG Bayou Cove LLC was formed in September 2001 for the purpose of developing, owning and operating an approximately 320 MW gas-fired peaking generating facility located near Jennings, Louisiana.

Recent Developments

On May 14, 2003, NRG Energy and 25 of its direct and indirect wholly owned subsidiaries commenced voluntary petitions under Chapter 11 of the bankruptcy code in the United States Bankruptcy Court for the Southern District of New York. The Company and its direct subsidiaries were included in the Chapter 11 filing. During the bankruptcy proceedings, NRG Energy continued to conduct business and manage the companies as debtors in possession pursuant to sections 1107(a) and 1108 of the bankruptcy code. Two plans of reorganization were filed in connection with the restructuring efforts. The first, filed on May 14, 2003, and referred to as NRG Energy's Plan of Reorganization, relates to NRG Energy and the other NRG Energy plan debtors. The second plan, relating to the Company, the Northeast Generating subsidiaries and the other South Central subsidiaries, referred to as the Northeast/ South Central Plan of Reorganization, was filed on September 17, 2003. On November 24, 2003, the bankruptcy court entered an order confirming NRG Energy's Plan of Reorganization and the plan became effective on December 5, 2003. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/ South Central Plan of Reorganization and the plan became effective on December 23, 2003. In connection with NRG Energy's emergence from bankruptcy, NRG Energy, adopted fresh start accounting in accordance with AICPA Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code* ("SOP 90-7") on December 5, 2003. NRG Energy's fresh start accounting was applied to the Company on a push down accounting basis with the financial statement impact recorded as an adjustment to the December 6, 2003 members' equity.

Northeast/ South Central Plan of Reorganization

The Northeast/ South Central Plan of Reorganization was proposed on September 17, 2003 after necessary financing commitments were secured. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/ South Central Plan of Reorganization and the plan became effective on December 23, 2003. In connection with the order confirming the Northeast/ South Central Plan of Reorganization, the court entered a separate order which provides that the allowed amount of the bondholders' claims shall equal in the aggregate the sum of (i) $1.3 billion plus (ii) any accrued and unpaid interest at the applicable contract rates through the date of payment to the indenture trustee plus (iii) the reasonable fees, costs or expenses of the collateral agent and indenture trustee (other than reasonable professional fees incurred from October 1, 2003) plus (iv) $19.6 million, ratably, for each holder of bonds based upon the current outstanding principal amount of the bonds and irrespective of (a) the date of maturity of the bonds, (b) the interest rate applicable to such bonds and (c) the issuer of the bonds.

The creditors of Northeast and South Central subsidiaries were unimpaired by the Northeast/ South Central Plan of Reorganization. The creditors holding allowed general secured claims were paid in cash, in full on the effective date of the Northeast/ South Central Plan of Reorganization. Holders of allowed unsecured claims have received either (i) cash equal to the unpaid portion of their allowed unsecured claim,

(ii) treatment that leaves unaltered the legal, equitable and contractual rights to which such unsecured claim entitles the holder of such claim, (iii) treatment that otherwise renders such unsecured claim unimpaired pursuant to section 1124 of the bankruptcy code or (iv) such other, less favorable treatment that is confirmed in writing as being acceptable to such holder and to the applicable debtor.

2. Summary of Significant Accounting Policies

Basis of Presentation

As used in these unaudited interim consolidated financial statements, “Predecessor Company” refers to the Company prior to NRG Energy’s emergence from bankruptcy. “Reorganized Company” refers to the Company after NRG Energy’s emergence from bankruptcy.

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with the Securities and Exchange Commission’s or “SEC” regulations for interim financial information. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. The accounting policies followed are set forth in Note 2 to the Company’s annual audited consolidated financial statements for the year ended December 31, 2003. The following notes should be read in conjunction with such policies and other disclosures. 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 necessary to present fairly the Company’s consolidated financial position as of June 30, 2004 and December 31, 2003, the results of its operations and members’ equity for the three and six months ended June 30, 2004 and 2003 and the cash flows for the six months ended June 30, 2004 and 2003. Certain prior-year amounts have been reclassified for comparative purposes.

Comparability of Financial Information

Due to NRG Energy’s adoption of Fresh Start as of December 5, 2003, the Reorganized Company’s consolidated balance sheet, statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company’s financial statements and are not comparable in certain respects to the financial statements prior to the application of push down accounting from NRG Energy’s fresh start accounting. A black line has been drawn on the accompanying consolidated financial statements (excluding the consolidated balance sheet) to separate and distinguish between the Reorganized Company and the Predecessor Company.

3. Other Charges

Reorganization items and restructuring and impairment charges included in operating costs and expenses in the consolidated statements of operations include the following:

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)			
Reorganization items	**$ (69)**	$ —	**$ 654**	$ —
Restructuring and impairment charges	**1,676**	2,135	**1,676**	$ 2,804
	$ 1,607	$ 2,135	**$ 2,330**	$ 2,804

For the six months ended June 30, 2004, the Company incurred $0.7 million of reorganization costs. All reorganization costs have been incurred since the Company filed for bankruptcy in May 2003. These costs consist of bankruptcy related charges primarily related to professional fees and liability settlements. For the three months ended June 30, 2004, a net credit of $69,000 was recorded related to the settlement of obligations recorded under Fresh Start accounting. No reorganization costs were recorded for the three and six months ended June 30, 2003.

The Company incurred total restructuring charges of approximately $2.1 million and $2.8 million, respectively, for the three and six months ended June 30, 2003. These costs consist of advisor fees. All amounts were paid during the first half of 2003.

The Company periodically reviews the recoverability of its long-lived assets in accordance with the guidelines of Statement of Financial Accounting Standards ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS 144"). In the second quarter of 2004, the Company made the decision to sell a turbine, whose carrying value was more than the sales price. Therefore, the Company recorded $1.7 million in impairment charges for the three and six months ended June 30, 2004. No impairment charges were recorded for the three and six months ended June 30, 2003.

4. Inventory

Inventory, which is valued at the lower of weighted average cost or market, consists of:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Coal	$20,915	$ 26,108
Spare parts	8,078	8,207
Fuel oil/gas	804	783
Total inventory	$29,797	$ 35,098

5. Property, Plant and Equipment

The major classes of property, plant and equipment were as follows:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Land	$ 30,935	$ 30,935
Facilities, machinery and equipment	885,655	885,656
Office furnishings and equipment	582	582
Construction in progress	25,594	329
Accumulated depreciation	(34,094)	(2,561)
Property, plant and equipment, net	$908,672	$ 914,941

6. Asset Retirement Obligation

Effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"). SFAS No. 143 requires an entity to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The Company identified certain retirement obligations within its operations. These asset retirement obligations are related primarily to the future dismantlement of equipment on leased property and environment obligations related to ash disposal site closures. The Company also identified similar other asset retirement obligations that could not be calculated because the assets associated with the retirement obligations were determined to have an indeterminate life. The adoption of SFAS No. 143 resulted in recording a $0.3 million increase to property, plant and equipment and a $0.4 million increase to other long-term obligations. The cumulative effect of adopting SFAS No. 143 was recorded as a $21,000 increase to depreciation expense and a $0.1 million increase to operating costs as the Company considered the cumulative effect to be immaterial.

The following represents the balances of the asset retirement obligation at January 1, 2004, and the accretion of the asset retirement obligation for the six months ended June 30, 2004, which is included in other long-term obligations in the consolidated balance sheets.

	Reorganized Company		
	Beginning Balance January 1, 2004	Accretion for the Six Months Ended June 30, 2004	Ending Balance June 30, 2004
	(In thousands of dollars)		
Asset retirement obligations	$ 2,638	$ 90	$2,728

7. Intangible Assets

Upon the application of push down accounting, the Company established certain intangible assets for power sales agreements and plant emission allowances. These intangible assets will be amortized over their respective lives based on a straight-line or units of production basis to resemble the Company’s realization of such assets.

Power sale agreements will be amortized as a reduction to revenue over the terms and conditions of each contract. The remaining amortization period is three years for the power sale agreements. Emission allowances will be amortized as additional fuel expense based upon the actual level of emissions from the respective plants through 2023. Aggregate amortization recognized for the three and six months ended June 30, 2004, was approximately $3.2 million and $6.5 million, respectively. The annual aggregate amortization for each of the five succeeding years is expected to approximate $11.5 million in years one through three and $5.0 million in years four and five for both the power sale agreements and emission allowances. The expected annual amortization of these amounts is expected to change as the Company relieves the tax valuation allowance, as explained below.

For the three and six months ended June 30, 2004, the Company reduced its tax valuation allowance by $5.6 million and $10.2 million, respectively, and in accordance with SOP 90-7, recorded a corresponding reduction related to the Company’s intangible assets. As a result of the recognition of a deferred tax asset valuation allowance in connection with push down accounting, any future benefits from reducing the valuation allowances should first reduce intangible assets until exhausted, and thereafter be recorded as a direct addition to paid in capital.

Intangible assets consisted of the following:

	Power Sale Agreements	Emission Allowances	Total
		(In thousands of dollars)	
Balances as of December 31, 2003	$ 27,013	$ 93,979	$120,992
Tax valuation adjustment	(2,271)	(7,904)	(10,175)
Amortization	(3,636)	(2,891)	(6,527)
Balances as of June 30, 2004	$ 21,106	$ 83,184	$104,290

8. Notes Payable — Affiliate

NRG South Central's long-term debt consists of the following:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
NRG Peaker — Bayou Cove — note payable affiliate due 2019 — 6.673%	$102,852	$ 105,491
Unamortized fair value adjustment	(22,553)	(23,818)
Subtotal	80,299	81,673
Less current maturities	1,002	81,673
Total	$ 79,297	$ —

Project Level Debt

On June 18, 2002, NRG Peaker Finance Company LLC ("NRG Peaker"), a wholly owned subsidiary of NRG Energy and an affiliate of the Company, issued $325 million of senior secured bonds. The bonds bear interest at a floating rate equal to three months USD-LIBOR BBA plus 1.07%. Interest on the bonds is payable on March 10, June 10, September 10, and December 10 of each year commencing on September 10, 2002. The Peaker projects which secure the senior secured bonds are a combination of several indirect wholly owned subsidiaries of NRG Energy, which include the following entities: Bayou Cove Peaking Power LLC ("Bayou Cove"), Big Cajun I Peaking Power LLC ("Big Cajun Peaking"), NRG Rockford LLC, Rockford II LLC and NRG Sterlington Power LLC ("Sterlington"). Three of these entities, Bayou Cove, Big Cajun Peaking and Sterlington, are wholly owned nonguarantor subsidiaries of the Company. NRG Peaker Finance Company LLC advanced unsecured loans in the amounts of $107.4 million to Bayou Cove through project loan agreements. The project owners used the gross proceeds of the loans to (1) reimburse NRG Energy for construction and/or acquisition costs for the peaker projects previously paid by NRG Energy, (2) pay to XL Capital Assurance ("XLCA") the premium for the Bond Policy, (3) provide funds to NRG Peaker to collateralize a portion of NRG Energy's contingent guaranty obligations and (4) pay transaction costs incurred in connection with the offering of the bonds (including reimbursement of NRG Energy for the portion of such costs previously paid by NRG Energy). At June 30, 2004 and December 31, 2003, Bayou Cove had an affiliate loan outstanding in the amount of $102.9 million and $105.5 million, respectively, in connection with the NRG Peaker bonds. The note bears a fixed interest rate of 6.673%. On the maturity date of June 10, 2019, the principal and accrued interest is due.

The bonds are secured by a pledge of membership interests in NRG Peaker and a security interest in all of its assets, which initially consisted of notes evidencing loans to the affiliate project owners, including Bayou Cove, Big Cajun Peaking and Sterlington. The project owners' jointly and severally guarantied the entire principal amount of the bonds and interest on such principal amount. The project owner guaranties are secured by a pledge of the membership interest in three of five project owners, including Bayou Cove, and a security interest in substantially all of the project owners' assets ("the peaker projects"), including equipment, real property rights, contracts and permits. NRG Energy has entered into a contingent guaranty agreement in favor of the collateral agent for the benefit of the secured parties, under which it agreed to make payments to cover scheduled principal and interest payments on the bonds and regularly scheduled payments under the interest rate swap agreement, to the extent that the net revenues from the peaker projects are insufficient to make such payments, in specified circumstances. This financing contains a cross-default provision related to the failure by NRG Energy to make payment of principal, interest or other amounts due on debt for borrowed money in excess of $50 million of payment defaults by NRG Energy, a covenant that was violated in October 2002. In addition, liens were placed against the Bayou Cove facility resulting in an additional default. NRG Peaker is in the process of getting such liens released. On October 22, 2002, XLCA issued a notice of default on the NRG Peaker financing facility. On December 10, 2002, $16.0 million in interest, principal and swap payments were made from NRG Energy's restricted cash accounts. As a result, $319.4 million in principal remains outstanding as of December 31, 2002. On May 12, 2003, XLCA accelerated the bonds, rendering the bonds immediately due and payable. Also on May 12, 2003, a forbearance agreement was entered into which forbears XLCA from exercising its rights and remedies.

On December 10, 2003, $31.1 million in interest, principal and swap payments were made from restricted cash accounts. As a result, $311.4 million in principal remains outstanding as of December 31, 2003.

On January 6, 2004, NRG Energy and XLCA consummated a comprehensive restructuring arrangement which provides for, among other things, the provision of a letter of credit by NRG Energy for the benefit of the secured parties in the NRG Peaker financing in lieu of the contingent guarantee described above, the cure or waiver of all defaults under the original financing agreement and the mutual release of claims by the parties. With the exception of distributions to pay taxes, distributions to equity holders are subject to tests regarding NRG Peaker reserve funding and financial ratios. At June 30, 2004, NRG Peaker was not in default under its financing agreements; therefore, Bayou Cove's debt has been reclassified to long-term.

In connection with the revaluation of NRG Peaker's debt to fair value under SOP 90-7, debt discounts were recorded in debt. At June 30, 2004 and December 31, 2003, the unamortized debt discounts recorded in debt were $68.3 million and $72.1 million, respectively. Approximately $22.6 million and $23.8 million of these amounts relate to Bayou Cove at June 30, 2004 and December 31, 2003, respectively.

In June 2002, NRG Peaker also entered into an interest rate swap agreement pursuant to which it agreed to make fixed rate interest payments and receive floating rate interest payments. The agreement effectively changed the interest exposure on the original $325 million of bonds from LIBOR plus 1.07% to a fixed rate of 6.67%. The interest rate swap counter-party will have a security interest in the collateral for the bonds and the collateral for the project owners' guarantees. Net payments to be made by NRG Peaker under the interest rate swap agreement will be guaranteed pursuant to a separate financial guaranty insurance policy with XLCA, the issuer of which will have a security interest in the collateral for the bonds and the collateral for the project owners' guaranties. NRG Peaker was in compliance with this agreement at December 31, 2003. The agreement expires in June 2019.

9. Derivative Instruments and Hedging Activity

SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"), as amended, requires the Company to record all derivatives on the consolidated balance sheet as assets or liabilities at fair value. For derivatives designated as cash flow hedges, the effective portion of the changes in fair value of the derivatives are recorded in accumulated other comprehensive income ("OCI") and subsequently recognized in earnings when the hedged items impact 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. Changes in the fair value of nonhedge derivatives will be immediately recognized in earnings. Additionally, many of the Company's sales and purchase agreements qualify as normal purchases and sales under SFAS No. 133, and are therefor exempt from fair value accounting treatment.

SFAS No. 133 applies to the Company's long-term power sales contracts, long-term fuel purchase contracts and other energy related commodities financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect investments in fuel inventories. At June 30, 2004, the Company had various commodity contracts extending through 2005. None of these contracts are designated as hedging instruments.

The Company has no derivative instruments classified as hedges and no deferred gains or losses in OCI at June 30, 2004 and December 31, 2003.

Statement of Operations

The following table summarizes the pre-tax effects of nonhedge derivatives on the Company's consolidated statements of operations for the three and six months ended:

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)			
Revenues	**$ 393**	$ 203	**$ 42**	$ 420
Cost of operations	**—**	144	**—**	3
Total statement of operations impact before tax	**$ 393**	$ 347	**$ 42**	$ 423

During the three and six months ended June 30, 2004 and 2003, the Company recognized no gain or loss due to the ineffectiveness of commodity cash flow hedges, and no components of NRG South Central's derivative instruments gains or losses were excluded from the assessment of effectiveness.

The Company's earnings for the three months ended June 30, 2004 and 2003, were increased by $0.4 million and $0.4 million, respectively and for the six months ended June 30, 2004 and 2003, the Company's earnings increased by $42,000 and $0.4 million, respectively associated with the changes in fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

10. Commitments and Contingencies

Contractual Commitments

Power Supply Agreements with the Distribution Cooperatives

During March 2000, Louisiana Generating entered into certain power supply agreements with eleven distribution cooperatives to provide energy, capacity and transmission services. The agreements are standardized into three types, Form A, B and C. In connection with the application of push down accounting, certain of Louisiana Generating's long-term power supply agreements were determined to be at above or below market rates. As a result, the Company valued these agreements and recognized the fair value of such contracts on the December 6, 2003 balance sheet. The fair value of these contracts that were deemed to be valuable have been included in intangible assets. The fair value of contracts determined to be significantly burdensome were recorded as noncurrent liabilities. The favorable and unfavorable contract valuation amounts will be amortized as a net increase to revenues over the terms and conditions of each contract. These contracts consist primarily of the long-term power sale agreements Louisiana Generating has with its cooperative customers and certain others. The gross carrying amount of the unfavorable out-of-market power sales agreements at both June 30, 2004 and December 31, 2003, was $342.2 million. During the three and six months ended June 30, 2004, approximately $3.5 million and $6.7 million, respectively, was amortized as an increase to revenues.

Form A Agreements

Six of the distribution cooperatives entered into Form A power supply agreements. The Form A agreement is an all-requirements power supply agreement which has an initial term of 25 years, commencing on March 31, 2000. After the initial term, the agreement continues on a year-to-year basis, unless terminated by either party giving five years advance notice.

Under the Form A power supply agreement, Louisiana Generating is obligated to supply the distribution cooperative all of the energy and capacity required by the distribution cooperative for service to its retail customers although the distribution cooperative has certain limited rights under which it can purchase energy and capacity from third parties.

Louisiana Generating must contract for all transmission service required to serve the distribution cooperative and will pass through the costs of transmission service to the cooperative. Louisiana Generating is required to supply at its cost, without pass through, control area services and ancillary services which transmission providers are not required to provide.

Louisiana Generating owns and maintains the substations and other facilities used to deliver energy and capacity to the distribution cooperative and charges the cooperative a monthly specific delivery facility charge for such facilities any additions to, or new delivery facilities. The initial monthly charge is 1% of the value of all of the distribution cooperative's specific delivery facilities. The cost of additional investment during the term of the agreement will be added to the initial value of the delivery facilities to calculate the monthly specific delivery facility charge.

Louisiana Generating charges the distribution cooperative a demand charge, a fuel charge and a variable operation and maintenance charge. The demand charge consists of two components, a capital rate and a fixed operation and maintenance rate. The distribution cooperatives have an option to choose one of two fuel options; all six have selected the first option which is a fixed fee through 2004 and determined using a formula which is based on gas prices and the cost of delivered coal for the period thereafter. At the end of the fifteenth year of the contract, the cooperatives may switch to the second fuel option. The second fuel option consists of a pass-through of fuel costs, with a guaranteed coal heat rate and purchased energy costs, excluding the demand component in purchased power. From time to time, Louisiana Generating may offer fixed fuel rates which the cooperative may elect to utilize. The variable operation and maintenance charge is fixed through 2004 and escalates at either approximately 3% per annum or in accordance with actual changes in specified indices as selected by the distribution cooperative. Five of the distribution cooperatives elected the fixed escalation provision and one elected the specified indices provision.

The Form A agreement also contains provisions for special rates for certain customers based on the economic development benefits the customer will provide and other rates to improve the distribution cooperative's ability to compete with service offered by political subdivisions.

Form B Agreements

One distribution cooperative selected the Form B Power Supply Agreement. The term of the Form B power supply agreement commences on March 31, 2000 and ends on December 31, 2024. The Form B power supply agreement allows the distribution cooperative the right to elect to limit its purchase obligations to "base supply" or also to purchase "supplemental supply." Base supply is the distribution cooperative's ratable share of the generating capacity purchased by Louisiana Generating from Cajun Electric. Supplemental supply is the cooperative's requirements in excess of the base supply amount. The distribution cooperative which selected the Form B agreement also elected to purchase supplemental supply.

Louisiana Generating charges the distribution cooperative a monthly specific delivery facility charge of approximately 1.75% of the depreciated net book value of the specific delivery facilities, including additional investment. The distribution cooperative may assume the right to maintain the specific delivery facilities and reduce the charge to 1.25% of the depreciated net book value of the specific delivery facilities. Louisiana Generating also charges the distribution cooperative its ratable share of 1.75% of the depreciated book value of common delivery facilities, which include communications, transmission and metering facilities owned by Louisiana Generating to provide supervisory control and data acquisition, and automatic control for its customers.

For base supply, Louisiana Generating charges the distribution cooperative a demand charge, an energy charge and a fuel charge. The demand charge for each contract year is set forth in the agreement and is subject to increase for environmental legislation or occupational safety and health laws enacted after the effective date of the agreement. Louisiana Generating can increase the demand charge to the extent its cost of providing supplemental supply exceeds $400 per kilowatt ("kW"). The energy charge is fixed through 2004, and decreased slightly for the remainder of the contract term. The fuel charge is a pass-through of fuel and purchased energy costs. The distribution cooperative may elect to be charged based on a guaranteed coal-fired heat rate of 10,600 British Thermal Units per kilowatt-hour ("Btu/kWh"), and it may also select fixed fuel factors as set forth in the agreement for each year through 2008. The one distribution cooperative which selected this form of agreement elected to utilize the fixed fuel factors. For the years after 2008, Louisiana Generating will offer additional fixed fuel factors for five-year periods that may be elected. For the years after 2008, the distribution cooperative may also elect to have its charges computed under the pass-through provisions with or without the guaranteed coal-fired heat rate.

At the beginning of year six, Louisiana Generating will establish a rate fund equal to the ratable share of $18 million. The amount of the fund will be approximately $720,000. This fund will be used to offset the energy costs of the Form B distribution cooperatives which elected the fuel pass-through provision of the fuel charge, to the extent the cost of power exceeds $0.04/kWh. Any funds remaining at the end of the term of the power supply agreement will be returned to Louisiana Generating.

Form C Agreements

Four distribution cooperatives selected the Form C power supply agreement. The Form C power supply agreement is identical to the Form A power supply agreement, except for the following.

The term of the Form C power supply agreement was for four years following the closing date of the acquisition of the Cajun facilities. In October 2003, the Louisiana Public Service Commission approved contract extensions for all four Form C distribution cooperatives for terms of an additional five or ten years.

Louisiana Generating will charge the distribution cooperative a demand rate, a variable operation and maintenance charge and a fuel charge. Louisiana Generating will not offer the distribution cooperatives which select the Form C agreement any new incentive rates, but will continue to honor existing incentive rates. At the end of the term of the agreement, the distribution cooperative is obligated to purchase the specific delivery facilities for a purchase price equal to the depreciated book value.

Louisiana Generating must contract for all transmission services required to serve the distribution cooperative and will pass through the costs of transmission service to the cooperative. Louisiana Generating is required to supply at its cost, without pass-through, control area services and ancillary services which transmission providers are not required to provide.

Louisiana Generating owns and maintains the substations and other facilities used to deliver energy and capacity to the distribution cooperative and charges the cooperative a monthly specific delivery facility charge for such facilities; any additions to, or new delivery facilities. The initial monthly charge is 1% of the value of all of the distribution cooperative's specific delivery facilities. The cost of additional investment during the term of the agreement will be added to the initial value of the delivery facilities to calculate the monthly specific delivery facility charge.

Included in the amended and restated Form C agreements is a provision for an annual $250,000 Economic Development Contribution to be shared among the four Form C distribution cooperatives, beginning in April 2004 and extending through the end of the contract terms.

Other Power Supply Agreements

Louisiana Generating assumed Cajun Electric's rights and obligations under two consecutive long-term power supply agreements with South Western Electric Power Company ("SWEPCO"), one agreement with South Mississippi Electric Power Association ("SMEPA") and one agreement with Municipal Energy Agency of Mississippi ("MEAM").

The SWEPCO Operating Reserves and Off-Peak Power Sale Agreement terminates on December 31, 2007. The agreement requires Louisiana Generating to supply 100 MW of off-peak energy during certain hours of the day to a maximum of 292,000 MWh per year and an additional 100 MW of operating reserve capacity and the associated energy within ten minutes of a phone request during certain hours to a maximum of 43,800 MWh of operating reserve energy per year. The obligation to purchase the 100 MW of off-peak energy is contingent on Louisiana Generating's ability to deliver operating reserve capacity and energy associated with operating reserve capacity. At Louisiana Generating's request, it will supply up to 100 MW of nonfirm, on peak capacity and associated energy.

The SWEPCO Operating Reserves Capacity and Energy Power Sale Agreement is effective January 1, 2008 through December 31, 2026. The agreement requires Louisiana Generating to provide 50 MW of operating reserve capacity within ten minutes of a phone request. In addition, SWEPCO is granted the right to purchase up to 21,900 MWh/year of operating reserve energy.

The SMEPA Unit Power Sale Agreement is effective through May 31, 2009, unless terminated following certain regulatory changes, changes in fuel costs or destruction of the Cajun facilities. The agreement requires Louisiana Generating to provide 75 MW of capacity and the associated energy from Big Cajun II, Unit 1 and an option for SMEPA to purchase additional capacity and associated energy if Louisiana Generating determines that it is available, in 10 MW increments, up to a total of 200 MW. SMEPA is required to schedule a minimum of 25 MW plus 37% of any additional capacity that is purchased. The capacity charge was fixed through May 31, 2004, and increased for the period from June 1, 2004 to May 31, 2009, including transmission costs to the delivery point and any escalation of expenses. The energy charge is 110% of the incremental fuel cost for Big Cajun II, Unit 1.

The MEAM Power Sale Agreement is effective through May 31, 2010, with an option for MEAM to extend through September 30, 2015, upon five years advance notice. The agreement requires Louisiana Generating to provide 20 MW of firm capacity and associated energy with an option for MEAM to increase the capacity purchased to a total of 30 MW upon five years advance notice. The capacity charge is fixed. The operation and maintenance charge is a fixed amount which escalates at 3.5% per year. There is a transmission charge which varies depending upon the delivery point. The price for energy associated with the firm capacity is 110% of the incremental generating cost to Louisiana Generating and is adjusted to include transmission losses to the delivery point.

Coal Supply Agreement

Louisiana Generating has entered into a coal supply agreement with Triton Coal. The coal is primarily sourced from Triton Coal's Buckskin and North Rochelle mines located in the Powder River Basin, Wyoming. The initial term of the coal supply agreement ends on March 31, 2005. The agreement establishes a base price per ton for coal supplied by Triton Coal. The base price is subject to adjustment for changes in the level of taxes or other government fees and charges, variations in the caloric value and sulfur content of the coal shipped, and changes in the price of SO(2) emission allowances. The base price is based on certain annual weighted average quality specifications, subject to suspension and rejection limits.

Coal Transportation Agreement

Louisiana Generating entered into a coal transportation agreement with Burlington Northern and Santa Fe Railway and American Commercial Terminal. The term of the agreement is five years from March 31, 2000. This agreement provides for the transportation of all of the coal requirements of Big Cajun II from the mines in Wyoming to Big Cajun II.

Transmission and Interconnection Agreements

Louisiana Generating assumed Cajun Electric's existing transmission agreements with Central Louisiana Electric Company, SWEPCO; and Entergy Services, Inc., acting as agent for Entergy Arkansas, Inc., Entergy Gulf States, Inc., Entergy Louisiana, Inc., Entergy Mississippi, Inc., and Entergy New Orleans, Inc. Louisiana Generating also entered into two interconnection and operating agreements with Entergy Gulf States, Inc. on May 1, 2002. The Cajun facilities are connected to the transmission system of Entergy Gulf States, Inc. and power is delivered to the distribution cooperative at various delivery points on the transmission systems of Entergy Gulf States, Inc., Entergy Louisiana, Inc., Central Louisiana Electric Company and SWEPCO. Louisiana Generating also assumed from Cajun Electric 20 interchange and sales agreements with utilities and cooperatives, providing access to a 12 state area.

Environmental Matters

The construction and operation of power projects are subject to stringent environmental and safety protection and land use laws and regulation in the United States. These laws and regulations generally require lengthy and complex processes to obtain licenses, permits and approvals from federal, state and local agencies. If such laws and regulations become more stringent and the Company's facilities are not exempted from coverage, the Company could be required to make extensive modifications to further reduce potential environmental impacts. Also, the Company could be held responsible under environmental and safety laws for the cleanup of pollutant releases at its facilities or at off-site locations where it has sent wastes.

The Company and its subsidiaries strive to exceed the standards of compliance with applicable environmental and safety regulations. Nonetheless, the Company expects that future liability under or compliance with environmental and safety requirements could have a material effect on its operations or competitive position. It is not possible at this time to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of possible changes to environmental and safety regulations, regulatory interpretations or enforcement policies. In general, the effect of future laws or regulations is expected to require the addition of pollution control equipment or the imposition of restrictions on the Company's operations.

The Company establishes accruals where reasonable estimates of probable environmental and safety liabilities are possible. The Company adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates are adjusted to reflect new information.

Under various federal, state and local environmental laws and regulations, a current or previous owner or operator of any facility, including an electric generating facility, may be required to investigate and remediate releases or threatened releases of hazardous or toxic substances or petroleum products located at the facility, and may be held liable to a governmental entity or to third parties for property damage, personal injury and investigation and remediation costs incurred by the party in connection with any releases or threatened releases. These laws, including the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended by the Superfund Amendments and Reauthorization Act of 1986, impose liability without regard to whether the owner knew of or caused the presence of the hazardous substances, and courts have interpreted liability under such laws to be strict (without fault) and joint and several. The cost of investigation, remediation or removal of any hazardous or toxic substances or petroleum products could be substantial. The Company has not been named as a potentially responsible party with respect to any off-site waste disposal matter.

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 (one of the instruments allowed by the Louisiana Department of Environmental Quality for providing financial assurance for expenses associated with closure and post-closure care of the ponds). The value of the trust fund is approximately $4.9 million at June 30, 2004, and the Company is making annual payments to the fund in the amount of about $116,000. See Note 13.

The Louisiana Department of Environmental Quality has promulgated State Implementation Plan revisions to bring the Baton Rouge ozone nonattainment area into compliance with National Ambient Air Quality Standards. The Company participated in development of the revisions, which require the reduction of NO(x) emissions at the gas-fired Big Cajun I Power Station and coal-fired Big Cajun II Power Station to 0.1 pounds NO(x) per million Btu heat input and 0.21 pounds NO(x) per million Btu heat input, respectively. This revision of the Louisiana air rules would appear to constitute a change-in-law covered by agreement between Louisiana Generating LLC and the electric cooperatives allowing the costs of added combustion controls to be passed through to the cooperatives. The capital cost of combustion controls required at the Big Cajun II Generating Station to meet the State's NO(x) regulations will total about $10.0 million for Unit 1. Units 2 and 3 have already made such changes. The capital cost of combustion controls required at the Big Cajun I Generating Station to meet the State's NO(x) regulations will total about $5 million to $10 million for the Unit 1 and 2 steam boilers.

Legal Issues

United States Environmental Protection Agency Request for Information under Section 114 of the Clean Air Act

On January 27, 2004, Louisiana Generating, LLC and Big Cajun II received a request for information under Section 114 of the Clean Air Act from the United States Environmental Protection Agency ("EPA") seeking information primarily relating to physical changes made at Big Cajun II in 1994 and 1995 by the predecessor owner of that facility. Louisiana Generating, LLC and Big Cajun II have been responding to the EPA request in an appropriate manner. At the present time, the Company cannot predict the probable outcome in this matter.

Travis Ballou, et al. v. Ralph Mabey, et al., United States Court of Appeals for the Fifth Circuit, No. 03-30343; Kenneth W. Austin, et al. v. Ralph Mabey, et al., United States District Court for the Middle District of Louisiana, Civil Action No. 00-728-D-M1

Two lawsuits are pending in Federal Court involving 39 former employees of Cajun Electric Power Cooperative, Inc. who claim age/race/sex discrimination in failure to hire by Louisiana Generating. One lawsuit was dismissed on summary judgment and has been appealed. In the remaining lawsuit, the Company is awaiting the District Court's ruling on Louisiana Generating's motions for summary judgment.

In the Matter of Louisiana Generating, LLC, Adversary Proceeding No. 2002-1095 1-EQ on the Docket of the Louisiana Division of Administrative Law

During 2000, the Louisiana Department of Environmental Quality ("DEQ") issued a Part 70 Air Permit modification to Louisiana Generating to construct and operate two 240 MW natural gas-fired turbines. The Part 70 Air Permit set emissions limits for the criteria air pollutants, including NO(x), based on the application of Best Available Control Technology ("BACT"). The BACT limitation for NO(x) was based on the guarantees of the manufacturer, Siemens-Westinghouse. Louisiana Generating sought an interim emissions limit to allow Siemens-Westinghouse time to install additional control equipment. To establish the interim limit, DEQ issued a Compliance Order and Notice of Potential Penalty, No. AE-CN-02-0022, on September 8, 2002, which is, in part, subject to the referenced administrative hearing. DEQ alleged that Louisiana Generating did not meet its NO(x) emissions limit on certain days, did not conduct all opacity monitoring and did not complete all record keeping and certification requirements. Louisiana Generating intends to vigorously defend certain claims and any future penalty assessment, while also seeking an amendment of its limit for NO(x). An initial status conference was held with the Administrative Law Judge and quarterly reports are being submitted to that judge to describe progress, including settlement and amendment of the limit. In late February 2004, the Company timely submitted to the DEQ an amended BACT analysis and amended Prevention of Significant Deterioration and Title V permit application to amend the NO(x) limit. The DEQ is presently processing the permit application. In addition, Louisiana Generating may assert breach of warranty claims against the manufacturer. With respect to the administrative action described above, at this time the Company is unable to predict the eventual outcome of this matter or the potential loss contingencies, if any, to which the Company may be subject.

11. Regulatory Issues

The Company's assets are located within the control area of Entergy Corporation ("Entergy"), a vertically integrated utility. The utility performs the scheduling, reserve and reliability functions that are administered by the ISOs in certain other regions of the United States and Canada. The Company operates a National Electric Reliability Council ("NERC") certified control area within the Entergy control area, which is comprised of the Company's generating assets and its co-op customer loads. Although the reliability functions performed are essentially the same, the primary differences between these markets lie principally in the physical delivery and price discovery mechanisms. In the South Central region, all power sales and purchases are consummated bilaterally between individual counter-parties, and physically delivered either within or across the physical control areas of the transmission owners from the source generator to the sink load. Transacting counter-parties are required to reserve and purchase transmission services from the intervening transmission owners at their FERC approved tariff rates. Included with these transmission services are the reserve and ancillary costs. Energy prices in the South Central region are determined and agreed to in bilateral negotiations between representatives of the transacting counter-parties, using market information gleaned by the individual marketing agents arranging the transactions.

In the South Central area, including Entergy's service territory, the present energy market is not a centralized market and does not have an independent system operator as is found in the Northeast markets. The Company presently has long-term all requirements contracts with 11 Louisiana Distribution Cooperatives, and long-term contracts with the Municipal Energy Agency of Mississippi, South Mississippi Electric Power Association and Southwestern Electric Power Company. The Distribution Cooperatives serve approximately 300,000 to 350,000 retail customers.

In the Southeast portion of the United States, Entergy and Southern Company recently discontinued their RTO initiative, SeTrans. On March 31, 2004, Entergy filed with FERC a proposal to have an independent person monitor the Entergy operation of the transmission system. FERC has not ruled on this request. Also, it is unclear at this time how these recent developments will impact the Company, or whether another RTO proposal will replace the SeTrans initiative.

12. Jointly Owned Plant

On March 31, 2000, Louisiana Generating acquired a 58% interest in the Big Cajun II, Unit 3 generation plant. Entergy Gulf States, Inc. owns the remaining 42%. Big Cajun II, Unit 3 is operated and maintained by Louisiana Generating pursuant to a joint ownership participation and operating agreement. Under this agreement, Louisiana Generating and Entergy Gulf States, Inc. are each entitled to their ownership percentage of the hourly net electrical output of Big Cajun II, Unit 3. All fixed costs are shared in proportion to the ownership interests. Fixed costs include the cost of operating common facilities. All variable costs are borne in proportion to the energy delivered to the owners. The Company's statements of operations include its share of all fixed and variable costs of operating the unit.

13. Decommissioning Fund

The Company is required by the State of Louisiana Department of Environmental Quality ("DEQ") to rehabilitate its Big Cajun II ash and wastewater impoundment areas upon removal from service of the Big Cajun II facilities. On July 1, 1989, a guarantor trust fund (the "Solid Waste Disposal Trust Fund") was established to accumulate the estimated funds necessary for such purpose. The Company's predecessor deposited $1.06 million in the Solid Waste Disposal Trust Fund in 1989, and funded $116,000 annually thereafter, based upon an estimated future rehabilitation cost (in 1989 dollars) of approximately $3.5 million and the remaining estimated useful life of the Big Cajun II facilities. Prior to January 1, 2003, cumulative contributions to the Solid Waste Disposal Trust Fund and earnings on the investments therein were accrued as a decommissioning liability. At June 30, 2004 and December 31, 2003, the carrying value of the trust fund investments and the related accrued decommissioning liability was approximately $4.9 million. The trust fund investments are comprised of various debt securities of the United States and are carried at amortized cost, which approximates their fair value.

14. Guarantees

In November 2002, the FASB issued Interpretation No. ("FIN") 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* The initial recognition and initial measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year end. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. The interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. The interpretation also clarifies the requirements related to the recognition of a liability by a guarantor at the inception of the guarantee for the obligations the guarantor has undertaken in issuing the guarantee.

In connection with the application of push down accounting, all outstanding guarantees were considered new; accordingly, the Company applied the provisions of FIN 45 to all of those guarantees. Each guarantee was reviewed for the requirement to recognize a liability at inception.

The Company guarantees the purchase and sale of fuel, emission credits and power generation to and from third parties in connection with the operation of some of the Company's generation facilities. At June 30, 2004 and December 31, 2003, the Company's obligations pursuant to its guarantees of the performance of its subsidiaries totaled approximately $13 million and $13 million, respectively. In addition, the Company had one guarantee related to the purchase of transmission service that has an indeterminate value at June 30, 2004 and December 31, 2003.

In June 2002, NRG Peaker issued $325 million of secured bonds to make loans to affiliates which own natural gas fired “peaker” electric generating projects. At June 30, 2004 and December 31, 2003, $243.1 million and $239.3 million, respectively, remains outstanding. NRG Peaker advanced unsecured loans in the amount of $107.4 million to Bayou Cove through project loan agreements. The remaining $217.6 million was advanced to NRG Rockford LLC and Rockford II LLC, indirect wholly owned subsidiaries of NRG Energy. At June 30, 2004 and December 31, 2003, Bayou Cove had an intercompany loan outstanding in the amount of $80.3 million and $81.7 million, respectively. The principal and interest payments, in addition to the obligation to pay fees and other finance expenses, in connection with the bonds are jointly and severally guaranteed by each of the three projects. As a result, NRG South Central’s obligation pursuant to its guarantee of the secured bonds is $243.1 million at June 30, 2004.

The Company is a guarantor under the debt issued by the Company’s ultimate parent, NRG Energy. NRG Energy issued $1.25 billion of 8% Second Priority Notes on December 23, 2003, due and payable on December 15, 2013. On January 28, 2004, NRG Energy also issued $475.0 million of Second Priority Notes, under the same terms and indenture as its December 23, 2003 offering.

NRG Energy’s payment obligations under the notes and all related Parity Lien Obligations are guaranteed on an unconditional basis by each of NRG Energy’s current and future restricted subsidiaries, of which the Company is one. The notes are jointly and severally guaranteed by each of the guarantors. The subsidiary guarantees of the notes are secured, on a second priority basis, equally and ratably with any future Parity Lien Debt, by security interest in all of the assets of the guarantors, except certain excluded assets, subject to liens securing parity lien debt and other permitted prior liens.

The Company’s obligations pursuant to its guarantees of the performance, equity and indebtedness obligations were as follows:

	Guarantee/ Maximum Exposure	Nature of Guarantee	Expiration Date	Triggering Event
		(In thousands of dollars)		
NRG Energy Second Priority Notes due 2013	$1,753,000	Obligations under credit agreement	2013	Nonperformance

15. Income Taxes

The Company is included in the consolidated tax return filings as a wholly owned indirect subsidiary of NRG Energy. Reflected in the financial statements and notes below are separate company federal and state tax provisions as if the Company had prepared separate filings. An income tax provision has been established on the accompanying consolidated financial statements as of the earliest period presented in order to reflect income taxes as if the Company filed its own tax return. The Company’s ultimate parent, NRG Energy, does not have a tax allocation agreement with its subsidiaries and prior to January 1, 2003, income taxes were not recorded or allocated to non tax paying entities or entities such as the Company which are treated as disregarded entities for tax purposes. Because the Company is not a party to a tax sharing agreement, current tax expense (benefit) is recorded as a capital contribution from (distribution to) the Company’s parent. The cumulative effect of recording an income tax provision (benefit) and deferred taxes resulted in recording as of December 31, 2002, a net deferred tax asset of $35.7 million, a valuation allowance to offset the net deferred tax asset and no impact to members’ equity.

Income taxes for the six months ended June 30, 2004 was a tax expense of $10.2 million compared to a tax expense of $0.0 million for the same period in 2003. The tax expense for the six months ended June 30, 2004 includes federal tax expense of $8.2 million and state tax expense of $2.0 million. The tax expense for the same period in 2003 includes federal tax expense of $0.0 million and state tax expense of $0.0 million.

Income taxes for the three months ended June 30, 2004 was a tax expense of $5.6 million compared to a tax expense of $0.0 million for the same period in 2003. The tax expense for the three months ended June 30, 2004 includes federal tax expense of $4.7 million and state tax expense of $0.9 million. The tax expense for the same period in 2003 includes federal tax expense of $0.0 million and state tax expense of $0.0 million.

The tax expense in 2004 is due to a reduction in deferred tax assets without a tax benefit for the corresponding reduction in valuation allowance. Due to the uncertainty of realization of deferred tax assets related to net operating losses and other temporary differences, the Company’s net deferred tax assets at December 5, 2003, were offset by a full valuation allowance of $237.8 million in accordance with SFAS No. 109. SOP 90-7 requires reductions in the valuation allowance subsequent to push down accounting as of December 5, 2003 should first reduce intangible assets until exhausted and thereafter be reported as a direct addition to paid-in-capital. Consequently, our effective tax rate in subsequent years will not benefit from reductions in the valuation allowance. For 2003, the tax expense resulting from a decrease in deferred tax assets was offset by a corresponding decrease in valuation allowance which had been established in an earlier year.

The effective income tax rate for the period ended June 30, 2004, differs from the statutory federal income tax rate of 35% due to state taxes and to the requirement that reductions to the valuation allowance as of December 5, 2003 (push down accounting) should first reduce intangible assets until exhausted. The effective income tax rate for the period ended June 30, 2003, differs from the statutory federal income tax rate of 35% due to state taxes.

As of June 30, 2004, the valuation allowance against net operating loss carryforwards was $89.0 million and the valuation allowance against other deferred tax assets was $138.4 million. As of December 31, 2003, a valuation allowance of $91.3 million was provided to account for potential limitations on utilization of net operating loss carryforwards, and a valuation allowance of $146.3 million was provided for other deferred tax assets. If unused, the net operating loss carryforward of $218.9 million generated in 2001 through 2003 will expire starting in 2021 and running through 2023.

EXHIBIT 99.6

NRG EASTERN LLC

FINANCIAL STATEMENTS

At June 30, 2004 and December 31, 2003, and for
the Three and Six Months Ended June 30, 2004 and 2003

NRG EASTERN LLC

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NRG EASTERN LLC

BALANCE SHEETS

(Unaudited)

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
ASSETS		
Investment in affiliate	$628,140	$ 567,740
Noncurrent deferred income tax	42,133	45,556
Total assets	$670,273	$ 613,296
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Accounts payable — affiliates	$ 3	$ —
Total current liabilities	3	—
Commitments and contingencies		
Member's equity	670,270	613,296
Total liabilities and member's equity	$670,273	$ 613,296

The accompanying notes are an integral part of these financial statements.

NRG EASTERN LLC

STATEMENTS OF OPERATIONS

(Unaudited)

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended		Six Months Ended	
	June 30, 2004	June 30, 2003	June 30, 2004	June 30, 2003
	(In thousands of dollars)			
General and administrative expenses	**$ 1**	$ —	**$ 3**	$ 2
Equity in earnings (losses) in unconsolidated affiliate	**28,272**	(143,105)	**66,561**	(157,720)
Income (loss) before income taxes	**28,271**	(143,105)	**66,558**	(157,722)
Income tax expense (benefit)	**12,151**	(61,509)	**28,608**	(67,792)
Net income (loss)	**$ 16,120**	$ (81,596)	**$ 37,950**	$ (89,930)

The accompanying notes are an integral part of these financial statements.

NRG EASTERN LLC

STATEMENTS OF MEMBER'S EQUITY

For the Three Months Ended June 30, 2004 and 2003
(Unaudited)

	Member Units	Member Amount	Member Contributions/ Distributions	Accumulated Net Income (Loss)	Accumulated Other Comprehensive Income	Total Member's Equity
				(In thousands of dollars)		
Balances at March 31, 2003 (Predecessor Company)	1,000	$ 1	$ 412,164	$ 25,270	$ 6,156	$443,591
Net loss				(81,596)		(81,596)
Impact of SFAS No. 133 for the three months ended June 30, 2003					(6,156)	(6,156)
Comprehensive loss						(87,752)
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 412,164	$ (56,326)	$ —	$355,839
Balances at March 31, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 625,913**	**$ 24,753**	**$ (7,635)**	**$643,032**
Net income				**16,120**		**16,120**
Impact of SFAS No. 133 for the three months ended June 30, 2004					**1,474**	**1,474**
Comprehensive income						**17,594**
Contribution from member			**9,644**			**9,644**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 635,557**	**$ 40,873**	**$ (6,161)**	**$670,270**

The accompanying notes are an integral part of these financial statements.

NRG EASTERN LLC

STATEMENTS OF MEMBER'S EQUITY

For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Member		Member Contributions/ Distributions	Accumulated Net Income (Loss)	Accumulated Other Comprehensive Income	Total Member's Equity
	Units	Amount				
				(In thousands of dollars)		
Balances at December 31, 2002 (Predecessor Company)	1,000	$ 1	$ 412,164	$ 33,604	$ 14,418	$ 460,187
Net loss				(89,930)		(89,930)
Impact of SFAS No. 133 for the six months ended June 30, 2003					(14,418)	(14,418)
Comprehensive loss						(104,348)
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 412,164	$ (56,326)	$ —	$ 355,839
Balances at December 31, 2003 (Reorganized Company)	**1,000**	**$ 1**	**$ 610,372**	**$ 2,923**	**$ —**	**$ 613,296**
Net income				**37,950**		**37,950**
Impact of SFAS No. 133 for the six months ended June 30, 2004					**(6,161)**	**(6,161)**
Comprehensive income						**31,789**
Contribution from member			**25,185**			**25,185**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 635,557**	**$ 40,873**	**$ (6,161)**	**$ 670,270**

The accompanying notes are an integral part of these financial statements.

NRG EASTERN LLC

STATEMENTS OF CASH FLOWS

(Unaudited)

	Reorganized Company	Predecessor Company
	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)	
Cash flows from operating activities		
Net income (loss)	**$ 37,950**	$ (89,930)
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Distributions (less than) in excess of equity earnings of unconsolidated affiliate	**(66,561)**	157,720
Deferred income taxes	**3,423**	(67,792)
Current tax expense — noncash contribution from member	**25,185**	—
Changes in assets and liabilities		
Accounts payable — affiliates	**3**	2
Net cash provided by operating activities	**—**	—
Net change in cash and cash equivalents	**—**	—
Cash and cash equivalents		
Beginning of period	**—**	—
End of period	**$ —**	$ —

The accompanying notes are an integral part of these financial statements.

NRG EASTERN LLC

NOTES TO FINANCIAL STATEMENTS

(Unaudited)

1. Organization

NRG Eastern LLC (the “Company”), a directly held wholly owned subsidiary of NRG Energy, Inc. (“NRG Energy”), primarily holds a 50% equity interest in NRG Northeast Generating LLC (“Northeast Gen”) which owns electric power generation plants in the northeastern region of the United States. Northeast Gen was formed in 1999 for the purpose of financing, acquiring, owning, operating and maintaining, through its subsidiaries and affiliates the power generation facilities owned by Arthur Kill Power LLC, Astoria Gas Turbine Power LLC, Connecticut Jet Power LLC, Devon Power LLC, Dunkirk Power LLC, Huntley Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, Oswego Harbor Power LLC and Somerset Power LLC.

Recent Developments

On May 14, 2003, NRG Energy and 25 of its direct and indirect wholly owned subsidiaries commenced voluntary petitions under Chapter 11 of the bankruptcy code in the United Sates Bankruptcy Court for the Southern District of New York. Northeast Gen was included in the Chapter 11 filing. During the bankruptcy proceedings, NRG Energy continued to conduct business and manage the companies as debtors in possession pursuant to sections 1107(a) and 1108 of the bankruptcy code. Two plans of reorganization were filed in connection with the restructuring efforts. The first, filed on May 14, 2003, and referred to as NRG Energy’s Plan of Reorganization, relates to NRG Energy and the other NRG Energy plan debtors. The second plan, relating to Northeast Gen, its subsidiaries and the South Central subsidiaries, referred to as the Northeast/ South Central Plan of Reorganization, was filed on September 17, 2003. On November 24, 2003, the bankruptcy court entered an order confirming NRG Energy’s Plan of Reorganization and the plan became effective on December 5, 2003. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/ South Central Plan of Reorganization and the plan became effective on December 23, 2003. In connection with NRG Energy’s emergence from bankruptcy, NRG Energy adopted fresh start accounting in accordance with AICPA Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code* (“SOP 90-7”) on December 5, 2003. NRG Energy’s fresh start accounting was applied to the Company on a push down accounting basis with the financial statement impact recorded as an adjustment to the December 6, 2003 member’s equity.

Northeast/ South Central Plan of Reorganization

The Northeast/ South Central Plan of Reorganization was proposed on September 17, 2003, after the necessary financing commitments were secured. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/ South Central Plan of Reorganization and the plan became effective on December 23, 2003. In connection with the order confirming the Northeast/ South Central Plan of Reorganization, the court entered a separate order which provides that the allowed amount of the bondholders’ claims shall equal in the aggregate the sum of (i) $1.3 billion plus (ii) any accrued and unpaid interest at the applicable contract rates through the date of payment to the indenture trustee plus (iii) the reasonable fees, costs or expenses of the collateral agent and indenture trustee (other than reasonable professional fees incurred from October 1, 2003) plus (iv) $19.6 million, ratably, for each holder of bonds based upon the current outstanding principal amount of the bonds and irrespective of (a) the date of maturity of the bonds, (b) the interest rate applicable to such bonds and (c) the issuer of the bonds.

The creditors of Northeast Gen and South Central subsidiaries were unimpaired by the Northeast/ South Central Plan of Reorganization. The creditors holding allowed general secured claims were paid in cash, in full on the effective date of the Northeast/ South Central Plan of Reorganization. Holders of allowed unsecured claims received either (i) cash equal to the unpaid portion of their allowed unsecured claim, (ii) treatment that leaves unaltered the legal, equitable and contractual rights to which such unsecured claim entitles the holder of such claim, (iii) treatment that otherwise renders such unsecured claim unimpaired pursuant to section 1124 of the bankruptcy code or (iv) such other, less favorable treatment that is confirmed in writing as being acceptable to such holder and to the applicable debtor.

2. Summary of Significant Accounting Policies

Basis of Presentation

As used in these unaudited interim financial statements, "Predecessor Company" refers to the Company prior to NRG Energy's emergence from bankruptcy. "Reorganized Company" refers to the Company after NRG Energy's emergence from bankruptcy.

The accompanying unaudited interim financial statements have been prepared in accordance with the Securities and Exchange Commission's or "SEC" regulations for interim financial information. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. The accounting policies followed are set forth in Note 2 to the Company's annual audited financial statements for the year ended December 31, 2003. The following notes should be read in conjunction with such policies and other disclosures. Interim results are not necessarily indicative of results for a full year.

In the opinion of management, the accompanying unaudited interim financial statements contain all material adjustments necessary to present fairly the Company's financial position as of June 30, 2004 and December 31, 2003, the results of its operations and member's equity for the three and six months ended June 30, 2004 and 2003 and cash flows for the six months ended June 30, 2004 and 2003. Certain prior-year amounts have been reclassified for comparative purposes.

Comparability of Financial Information

Due to NRG Energy's adoption of Fresh Start as of December 5, 2003, the Reorganized Company's balance sheet, statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are not comparable in certain respects to the financial statements prior to the application of push down accounting from NRG Energy's fresh start accounting. A black line has been drawn on the accompanying financial statements (excluding the balance sheet) to separate and distinguish between the Reorganized Company and the Predecessor Company.

3. Derivative Instruments and Hedging Activity

Statement of Financial Accounting Standards SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"), as amended, requires the Company to record all derivatives on the balance sheet as assets or liabilities at fair value. For derivatives designated as cash flow hedges, the effective portion of the changes in fair value of the derivatives are recorded in accumulated other comprehensive income ("OCI") and subsequently recognized in earnings when the hedged items impact 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. Changes in the fair value of nonhedge derivatives will be immediately recognized in earnings.

SFAS No. 133 applies to the Northeast Gen's long-term power sales contracts, long-term fuel purchase contracts and other energy related commodities financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect investments in fuel inventories. At June 30, 2004, Northeast Gen had various commodity contracts extending through December 2005.

Energy Related Commodities

The Company is exposed to commodity price variability in electricity, emission allowances, natural gas, oil and coal used to meet fuel requirements. In order to manage these commodity price risks, the Company entered into financial instruments, which may take the form of fixed price, floating price or indexed sales or purchases, and options, such as puts, calls, basic transactions and swaps. Certain of these transactions have been designated as cash flow hedges. The Company has accounted for these derivatives by recording the effective portion of the cumulative gain or loss on the derivative instruments as a component of OCI in member's equity. The Company recognizes deferred gains and losses into earnings in the same period or periods during which the hedged transaction affects earnings. Such reclassifications are included on the same line of the statement of operations in which the hedged item is recorded.

Accumulated Other Comprehensive Income

The following table summarizes the effects of SFAS No. 133 on the Company's accumulated other comprehensive income balance attributable to hedged derivatives:

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
	(In thousands of dollars)			
Energy Commodities Gains (Losses)				
Beginning Balance	**$ (7,635)**	$ 6,156	**$ —**	$ 14,418
Unwound from OCI during period Due to unwinding of previously deferred amounts	**4,278**	(6,156)	**4,567**	(14,418)
Mark to market of hedge contracts	**(2,804)**	—	**(10,728)**	—
Ending Balance	**$ (6,161)**	$ —	**$ (6,161)**	$ —
Losses expected to unwind from OCI during next 12 months	**$ (6,709)**	$ —	**$ (6,709)**	$ —

Reorganized Company

Losses of $4.3 and $4.6 million were reclassified from OCI to current period earnings during the three and six months ended June 30, 2004, due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items are recorded. Also, during the three and six months ended June 30, 2004, the Company recorded losses in OCI of approximately $2.8 million and $10.7 million, respectively, related to changes in the fair values of derivatives accounted for as hedges.

The net balance in OCI relating to SFAS No. 133 as of June 30, 2004, was an unrecognized loss of approximately $6.2 million. The Company expects $6.7 million of deferred net losses on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

Predecessor Company

Gains of $6.2 million and $14.4 million were reclassified from OCI to current period earnings during the three and six months ended June 30, 2003, due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items are recorded. Also, during the three and six months ended June 30, 2003, the Company recorded no amounts related to changes in the fair values of derivatives accounted for as hedges. The net balance in OCI relating to SFAS No. 133 as of June 30, 2003, was $0.

4. Guarantees

In November 2002, the FASB issued FASB Interpretation No. ("FIN") 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* The initial recognition and initial measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year end. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. The interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. The interpretation also clarifies the requirements related to the recognition of a liability by a guarantor at the inception of the guarantee for the obligations the guarantor has undertaken in issuing the guarantee.

In connection with the application of push down accounting, all outstanding guarantees were considered new; accordingly, the Company applied the provision of FIN 45 to all of these guarantees. Each guarantee was reviewed for the requirement to recognize a liability at inception.

Northeast Gen and the Company are guarantors under the debt issued by the Company's parent, NRG Energy. NRG Energy issued $1.25 billion of 8% Second Priority Notes on December 23, 2003, due and payable on December 15, 2013. On January 28, 2004, NRG Energy also issued $475.0 million of Second Priority Notes, under the same terms and indenture as its December 23, 2003 offering.

NRG Energy's payment obligations under the notes and all related Parity Lien Obligations are guaranteed on an unconditional basis by each of NRG Energy's current and future restricted subsidiaries, of which the Company is one. The notes are jointly and severally guaranteed by each of the guarantors. The subsidiary guarantees of the notes are secured, on a second priority basis, equally and ratably with any future Parity Lien Debt, by security interests in all of the assets of the guarantors, except certain excluded assets, subject to liens securing parity lien debt and other permitted prior liens.

The Company's obligations pursuant to its guarantees of the performance, equity and indebtedness obligations were as follows:

	Guarantee/ Maximum Exposure	Nature of Guarantee	Expiration Date	Triggering Event
		(In thousands of dollars)		
NRG Energy Second Priority Notes due 2013	$1,753,000	Obligations under credit agreement	2013	Nonperformance

5. Investments Accounted for by the Equity Method

The Company has a 50% equity investment in NRG Northeast Generating LLC which owns electric power generation plants in the northeast region of the United States. Northeast Generation Holding LLC owns the remaining 50% interest in NRG Northeast Generating LLC. The equity method of accounting is applied to such investments in affiliates, which include joint ventures and partnerships because the ownership structure prevents the Company from exercising a controlling influence over operating and financial policies of the projects. Under this method, equity in the pretax income or losses of such projects are reflected as equity in earnings of unconsolidated affiliates.

Summarized financial information of the Company's only unconsolidated affiliate, NRG Northeast Generating LLC, without the impact of income taxes recorded is as follows:

Results of operations:

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)			
Operating revenues	**$ 229,542**	$ 163,172	**$ 505,672**	$ 343,386
Costs and expenses	**172,999**	449,381	**372,551**	658,826
Net income (loss) before taxes	**$ 56,543**	$ (286,209)	**$ 133,121**	$ (315,440)

Financial position:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Current assets	$ 297,181	$ 162,283
Other assets	1,039,125	1,064,874
Total assets	$1,336,306	$1,227,157
Current liabilities	$ 68,470	$ 84,149
Other liabilities	11,557	7,528
Member's equity	1,256,279	1,135,480
Total liabilities and member's equity	$1,336,306	$1,227,157

6. Income Taxes

The Company is included in the consolidated tax return filings as a wholly owned indirect subsidiary of NRG Energy. Reflected in the financial statements and notes below are separate company federal and state tax provisions as if the Company had prepared separate filings. An income tax provision has been established on the accompanying financial statements as of the earliest period presented in order to reflect income taxes as if the Company filed its own tax return. The Company's parent, NRG Energy, does not have a tax allocation agreement with its subsidiaries and prior to January 1, 2003, income taxes were not recorded or allocated to non tax paying entities or entities such as the Company which are treated as disregarded entities for tax purposes. Because the Company is not a party to a tax sharing agreement, current tax expense (benefit) is recorded as a capital contribution from (distribution to) the Company's parent. The cumulative effect of recording an income tax provision (benefit) and deferred taxes resulted in recording as of December 31, 2002, a net deferred tax liability of $29.2 million and a reduction to member's equity of $29.2 million.

Income taxes for the six months ended June 30, 2004 was a tax expense of $28.6 million compared to a tax benefit of $67.8 million for the same period in 2003. The tax expense for the six months ended June 30, 2004 includes federal tax expense of $20.4 million and state tax expense of $8.2 million. The tax benefit for the same period in 2003 includes federal tax benefit of $48.4 million and state tax benefit of $19.4 million.

Income taxes for the three months ended June 30, 2004 was a tax expense of $12.2 million compared to a tax benefit of $61.5 million for the same period in 2003. The tax expense for the three months ended June 30, 2004 includes federal tax expense of $8.7 million and state tax expense of $3.5 million. The tax benefit for the same period in 2003 includes federal tax benefit of $43.9 million and state tax benefit of $17.6 million.

The effective income tax rate for the periods ended June 30, 2004 and 2003, differs from the statutory federal income tax rate of 35% due to state taxes.

As of June 30, 2004 and December 31, 2003, the Company had $42.1 million and $45.6 million, respectively, of noncurrent deferred tax assets attributable primarily to differences between book and tax basis of investment in project. A valuation allowance was not established against these deferred tax assets given the likelihood of realization.

7. Commitments and Contingencies

In the normal course of business, the Company is subject to various claims and litigation. Management of the Company expects that these various litigation items will not have a material adverse effect on the results of operations or financial position of the Company.

EXHIBIT 99.7

NORTHEAST GENERATION HOLDING LLC

FINANCIAL STATEMENTS

At June 30, 2004 and December 31, 2003, and for the Three and Six Months Ended June 30, 2004 and 2003

NORTHEAST GENERATION HOLDING LLC

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NORTHEAST GENERATION HOLDING LLC

BALANCE SHEETS

(Unaudited)

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
ASSETS		
Investment in affiliate	$628,140	$ 567,740
Noncurrent deferred income tax	42,133	45,556
Total assets	$670,273	$ 613,296
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Accounts payable — affiliates	$ 10	$ 5
Total current liabilities	10	5
Commitments and contingencies		
Member's equity	670,263	613,291
Total liabilities and member's equity	$670,273	$ 613,296

The accompanying notes are an integral part of these financial statements.

NORTHEAST GENERATION HOLDING LLC

STATEMENTS OF OPERATIONS

(Unaudited)

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended		Six Months Ended	
	June 30, 2004	June 30, 2003	June 30, 2004	June 30, 2003
	(In thousands of dollars)			
General and administrative expenses	**$ —**	$ —	**$ 4**	$ —
Equity earnings (losses) in unconsolidated affiliate	**28,271**	(143,105)	**66,560**	(157,720)
Income (loss) before income taxes	**28,271**	(143,105)	**66,556**	(157,720)
Income tax expense (benefit)	**12,151**	(61,509)	**28,607**	(67,791)
Net income (loss)	**$ 16,120**	$ (81,596)	**$ 37,949**	$ (89,929)

The accompanying notes are an integral part of these financial statements.

NORTHEAST GENERATION HOLDING LLC

STATEMENTS OF MEMBER'S EQUITY

For the Three Months Ended June 30, 2004 and 2003
(Unaudited)

	Member Units	Member Amount	Member Contributions/ Distributions	Accumulated Net Income (Loss)	Accumulated Other Comprehensive Income	Total Member's Equity
			(In thousands of dollars)			
Balances at March 31, 2003 (Predecessor Company)	1,000	$ 1	$ 412,413	$ 25,417	$ 6,155	$443,986
Net loss				(81,596)		(81,596)
Impact of SFAS No. 133 for the three months ended June 30, 2003					(6,155)	(6,155)
Comprehensive loss						(87,751)
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 412,413	$ (56,179)	$ —	$356,235
Balances at March 31, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 625,910**	**$ 24,749**	**$ (7,635)**	**$643,025**
Net income				**16,120**		**16,120**
Impact of SFAS No. 133 for the three months ended June 30, 2004					**1,474**	**1,474**
Comprehensive income						**17,594**
Contribution from member			**9,654**			**9,654**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 635,564**	**$ 40,869**	**$ (6,161)**	**$670,273**

The accompanying notes are an integral part of these financial statements.

NORTHEAST GENERATION HOLDING LLC

STATEMENTS OF MEMBER'S EQUITY

For the Six Months Ended June 30, 2004 and 2003
(Unaudited)

	Member Units	Member Amount	Member Contributions/ Distributions	Accumulated Net Income (Loss)	Accumulated Other Comprehensive Income	Total Member's Equity
			(In thousands of dollars)			
Balances at December 31, 2002 (Predecessor Company)	1,000	$ 1	$ 412,413	$ 33,750	$ 14,417	$ 460,581
Net loss				(89,929)		(89,929)
Impact of SFAS No. 133 for the six months ended June 30, 2003					(14,417)	(14,417)
Comprehensive loss						(104,346)
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 412,413	$ (56,179)	$ —	$ 356,235
Balances at December 31, 2003 (Reorganized Company)	**1,000**	**$ 1**	**$ 610,370**	**$ 2,920**	**$ —**	**$ 613,291**
Net income				**37,949**		**37,949**
Impact of SFAS No. 133 for the six months ended June 30, 2004					**(6,161)**	**(6,161)**
Comprehensive income						**31,788**
Contribution from member			**25,194**			**25,194**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 635,564**	**$ 40,869**	**$ (6,161)**	**$ 670,273**

The accompanying notes are an integral part of these financial statements.

NORTHEAST GENERATION HOLDING LLC

STATEMENTS OF CASH FLOWS

(Unaudited)

	Reorganized Company	Predecessor Company
	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)	
Cash flows from operating activities		
Net income (loss)	**$ 37,949**	$ (89,929)
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Distributions (less than) in excess of equity earnings of unconsolidated affiliate	**(66,560)**	157,720
Deferred income taxes	**3,413**	(67,791)
Current tax expense — noncash contribution from member	**25,194**	—
Changes in assets and liabilities		
Accounts payable — affiliates	**4**	—
Net cash provided by operating activities	**—**	—
Net change in cash and cash equivalents	**—**	—
Cash and cash equivalents		
Beginning of period	**—**	—
End of period	**$ —**	$ —

The accompanying notes are an integral part of these financial statements.

NORTHEAST GENERATION HOLDING LLC

NOTES TO FINANCIAL STATEMENTS

(Unaudited)

1. Organization

Northeast Generation Holding LLC (the "Company"), a directly held wholly owned subsidiary of NRG Energy, Inc. ("NRG Energy"), primarily holds a 50% equity interest in NRG Northeast Generating LLC ("Northeast Gen") which owns electric power generation plants in the northeastern region of the United States. Northeast Gen was formed in 1999 for the purpose of financing, acquiring, owning, operating and maintaining, through its subsidiaries and affiliates the power generation facilities owned by Arthur Kill Power LLC, Astoria Gas Turbine Power LLC, Connecticut Jet Power LLC, Devon Power LLC, Dunkirk Power LLC, Huntley Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC, Oswego Harbor Power LLC and Somerset Power LLC.

Recent Developments

On May 14, 2003, NRG Energy and 25 of its direct and indirect wholly owned subsidiaries commenced voluntary petitions under Chapter 11 of the bankruptcy code in the United States Bankruptcy Court for the Southern District of New York. Northeast Gen was included in the Chapter 11 filing. During the bankruptcy proceedings, NRG Energy continued to conduct business and manage the companies as debtors in possession pursuant to sections 1107(a) and 1108 of the bankruptcy code. Two plans of reorganization were filed in connection with the restructuring efforts. The first, filed on May 14, 2003, and referred to as NRG Energy's Plan of Reorganization, relates to NRG Energy and the other NRG Energy plan debtors. The second plan, relating to Northeast Gen, its subsidiaries and the South Central subsidiaries, referred to as the Northeast/ South Central Plan of Reorganization, was filed on September 17, 2003. On November 24, 2003, the bankruptcy court entered an order confirming NRG Energy's Plan of Reorganization and the plan became effective on December 5, 2003. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/ South Central Plan of Reorganization and the plan became effective on December 23, 2003. In connection with NRG Energy's emergence from bankruptcy, NRG Energy adopted fresh start accounting in accordance with AICPA Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code* ("SOP 90-7") on December 5, 2003. NRG Energy's fresh start accounting was applied to the Company on a push down accounting basis with the financial statement impact recorded as an adjustment to the December 6, 2003 member's equity.

Northeast/ South Central Plan of Reorganization

The Northeast/ South Central Plan of Reorganization was proposed on September 17, 2003, after the necessary financing commitments were secured. On November 25, 2003, the bankruptcy court issued an order confirming the Northeast/ South Central Plan of Reorganization and the plan became effective on December 23, 2003. In connection with the order confirming the Northeast/ South Central Plan of Reorganization, the court entered a separate order which provides that the allowed amount of the bondholders' claims shall equal in the aggregate the sum of (i) $1.3 billion plus (ii) any accrued and unpaid interest at the applicable contract rates through the date of payment to the indenture trustee plus (iii) the reasonable fees, costs or expenses of the collateral agent and indenture trustee (other than reasonable professional fees incurred from October 1, 2003) plus (iv) $19.6 million, ratably, for each holder of bonds based upon the current outstanding principal amount of the bonds and irrespective of (a) the date of maturity of the bonds, (b) the interest rate applicable to such bonds and (c) the issuer of the bonds.

The creditors of Northeast Gen and South Central subsidiaries were unimpaired by the Northeast/ South Central Plan of Reorganization. The creditors holding allowed general secured claims were paid in cash, in full on the effective date of the Northeast/ South Central Plan of Reorganization. Holders of allowed unsecured claims received either (i) cash equal to the unpaid portion of their allowed unsecured claim, (ii) treatment that leaves unaltered the legal, equitable and contractual rights to which such unsecured claim entitles the holder of such claim, (iii) treatment that otherwise renders such unsecured claim unimpaired pursuant to section 1124 of the bankruptcy code or (iv) such other, less favorable treatment that is confirmed in writing as being acceptable to such holder and to the applicable debtor.

2. Summary of Significant Accounting Policies

Basis of Presentation

As used in these unaudited interim financial statements, "Predecessor Company" refers to the Company prior to NRG Energy's emergence from bankruptcy. "Reorganized Company" refers to the Company after NRG Energy's emergence from bankruptcy.

The accompanying unaudited interim financial statements have been prepared in accordance with the Securities and Exchange Commission's or "SEC" regulations for interim financial information. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. The accounting policies followed are set forth in Note 2 to the Company's annual audited financial statements for the year ended December 31, 2003. The following notes should be read in conjunction with such policies and other disclosures. Interim results are not necessarily indicative of results for a full year.

In the opinion of management, the accompanying unaudited interim financial statements contain all material adjustments necessary to present fairly the Company's financial position as of June 30, 2004 and December 31, 2003, the results of its operations and member's equity for the three and six months ended June 30, 2004 and 2003 and the cash flows for the six months ended June 30, 2004 and 2003. Certain prior-year amounts have been reclassified for comparative purposes.

Comparability of Financial Information

Due to NRG Energy's adoption of Fresh Start as of December 5, 2003, the Reorganized Company's balance sheet, statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are not comparable in certain respects to the financial statements prior to the application of push down accounting from NRG Energy's fresh start accounting. A black line has been drawn on the accompanying financial statements (excluding the balance sheet) to separate and distinguish between the Reorganized Company and the Predecessor Company.

3. Derivative Instruments and Hedging Activity

Statement of Financial Accounting Standards SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"), as amended, requires the Company to record all derivatives on the balance sheet as assets or liabilities at fair value. For derivatives designated as cash flow hedges, the effective portion of the changes in fair value of the derivatives are recorded in accumulated other comprehensive income ("OCI") and subsequently recognized in earnings when the hedged items impact 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. Changes in the fair value of nonhedge derivatives will be immediately recognized in earnings.

SFAS No. 133 applies to the Northeast Gen's long-term power sales contracts, long-term fuel purchase contracts and other energy related commodities financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect investments in fuel inventories. At June 30, 2004, Northeast Gen had various commodity contracts extending through December 2005.

Energy Related Commodities

The Company is exposed to commodity price variability in electricity, emission allowances, natural gas, oil and coal used to meet fuel requirements. In order to manage these commodity price risks, the Company entered into financial instruments, which may take the form of fixed price, floating price or indexed sales or purchases, and options, such as puts, calls, basic transactions and swaps. Certain of these transactions have been designated as cash flow hedges. The Company has accounted for these derivatives by recording the effective portion of the cumulative gain or loss on the derivative instruments as a component of OCI in member's equity. The Company recognizes deferred gains and losses into earnings in the same period or periods during which the hedged transaction affects earnings. Such reclassifications are included on the same line of the statement of operations in which the hedged item is recorded.

Accumulated Other Comprehensive Income

The following table summarizes the effects of SFAS No. 133 on the Company's accumulated other comprehensive income balance attributable to hedged derivatives:

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)			
Energy Commodities Gains (Losses)				
Beginning Balance	**$ (7,635)**	$ 6,155	**$ —**	$ 14,417
Unwound from OCI during period				
Due to unwinding of previously deferred amounts	**4,278**	(6,155)	**4,566**	(14,417)
Mark to market of hedge contracts	**(2,804)**	—	**(10,727)**	—
Ending Balance	**$ (6,161)**	$ —	**$ (6,161)**	$ —
Losses expected to unwind from OCI during next 12 months	**$ (6,709)**	$ —	**(6,709)**	$ —

Reorganized Company

Losses of $4.3 million and $4.6 million were reclassified from OCI to current period earnings during the three and six months ended June 30, 2004, due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items are recorded. Also, during the three and six months ended June 30, 2004, the Company recorded losses in OCI of approximately $2.8 million and $10.7 million, respectively, related to changes in the fair values of derivatives accounted for as hedges.

The net balance in OCI relating to SFAS No. 133 as of June 30, 2004, was an unrecognized loss of approximately $6.2 million. The Company expects $6.7 million of deferred net losses on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

Predecessor Company

Gains of $6.2 million and $14.4 million were reclassified from OCI to current period earnings during the three and six months ended June 30, 2003, due to the unwinding of previously deferred amounts. These amounts are recorded on the same line in the statement of operations in which the hedged items are recorded.

Also, during the three and six months ended June 30, 2003, the Company recorded no amounts related to changes in the fair values of derivatives accounted for as hedges. The net balance in OCI relating to SFAS No. 133 as of June 30, 2003, was $0.

4. Guarantees

In November 2002, the FASB issued FASB Interpretation No. ("FIN") 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* The initial recognition and initial measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year end. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. The interpretation addresses the disclosures to be made by guarantor in its interim and annual financial statements about its obligations under guarantees. The interpretation also clarifies the requirements related to the recognition of a liability by a guarantor at the inception of the guarantee for the obligations the guarantor has undertaken in issuing the guarantee.

In connection with the application of push down accounting, all outstanding guarantees were considered new; accordingly, the Company applied the provisions of FIN 45 to all of these guarantees. Each guarantee was reviewed for the requirement to recognize a liability at inception.

Northeast Gen and the Company are guarantors under the debt issued by the Company's parent, NRG Energy. NRG Energy issued $1.25 billion of 8% Second Priority Notes on December 23, 2003, due and payable on December 15, 2013. On January 28, 2004, NRG Energy also issued $475.0 million of Second Priority Notes, under the same terms and indenture as its December 23, 2003 offering.

NRG Energy's payment obligations under the notes and all related Parity Lien Obligations are guaranteed on an unconditional basis by each of NRG Energy's current and future restricted subsidiaries, of which the Company is one. The notes are jointly and severally guaranteed by each of the guarantors. The subsidiary guarantees of the notes are secured, on a second priority basis, equally and ratably with any future Parity Lien Debt, by security interests in all the assets of the guarantors, except certain excluded assets, subject to liens securing parity lien debt and other permitted prior liens.

The Company's obligations pursuant to its guarantees of the performance, equity and indebtedness obligations were as follows:

	Guarantee/ Maximum Exposure	Nature of Guarantee	Expiration Date	Triggering Event
	(In thousands of dollars)			
NRG Energy Second Priority Notes due 2013	$1,753,000	Obligations under credit agreement	2013	Nonperformance

5. Investments Accounted for by the Equity Method

The Company has a 50% equity investment in NRG Northeast Generating LLC which owns electric power generation plants in the northeast region of the United States. NRG Eastern LLC owns the remaining 50% interest in NRG Northeast Generating LLC. The equity method of accounting is applied to such investments in affiliates, which include joint ventures and partnerships because the ownership structure prevents the Company from exercising a controlling influence over operating and financial policies of the projects. Under this method, equity in the pretax income or losses of such projects are reflected as equity in earnings of unconsolidated affiliates.

Summarized financial information of the Company's only unconsolidated affiliate, NRG Northeast Generating LLC, without the impact of income taxes recorded is as follows:

Results of operations:

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
	(In thousands of dollars)			
Operating revenues	**$ 229,542**	$ 163,172	**$ 505,672**	$ 343,386
Costs and expenses	**172,999**	449,381	**372,551**	658,826
Net income (loss) before taxes	**$ 56,543**	$ (286,209)	**$ 133,121**	$(315,440)

Financial position:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Current assets	$ 297,181	$ 162,283
Other assets	1,039,125	1,064,874
Total assets	$1,336,306	$1,227,157
Current liabilities	$ 68,470	$ 84,149
Other liabilities	11,557	7,528
Member's equity	1,256,279	1,135,480
Total liabilities and member's equity	$1,336,306	$1,227,157

6. Income Taxes

The Company is included in the consolidated tax return filings as a wholly owned indirect subsidiary of NRG Energy. Reflected in the financial statements and notes below are separate company federal and state tax provisions as if the Company had prepared separate filings. An income tax provision has been established on the accompanying financial statements as of the earliest period presented in order to reflect income taxes as if the Company filed its own tax return. The Company's parent, NRG Energy, does not have a tax allocation agreement with its subsidiaries and prior to January 1, 2003, income taxes were not recorded or allocated to non tax paying entities or entities such as the Company which are treated as disregarded entities for tax purposes. Because the Company is not a party to a tax sharing agreement, current tax expense (benefit) is recorded as a capital contribution from (distribution to) the Company's parent. The cumulative effect of recording an income tax provision (benefit) and deferred taxes resulted in recording as of December 31, 2002, a net deferred tax liability of 29.2 million and a reduction to member's equity of $29.2 million.

Income taxes for the six months ended June 30, 2004 was a tax expense of $28.6 million compared to a tax benefit of $67.8 million for the same period in 2003. The tax expense for the six months ended June 30, 2004 includes federal tax expense of $20.4 million and state tax expense of $8.2 million. The tax benefit for the same period in 2003 includes federal tax benefit of $48.4 million and state tax benefit of $19.4 million.

Income taxes for the three months ended June 30, 2004 was a tax expense of $12.2 million compared to a tax benefit of $61.5 million for the same period in 2003. The tax expense for the three months ended June 30, 2004 includes federal tax expense of $8.7 million and state tax expense of $3.5 million. The tax benefit for the same period in 2003 includes federal tax benefit of $43.9 million and state tax benefit of $17.6 million.

The effective income tax rate for the periods ended June 30, 2004 and 2003, differs from the statutory federal income tax rate of 35% due to state taxes.

As of June 30, 2004 and December 31, 2003, the Company had $42.1 million and $45.6 million, respectively, of noncurrent deferred tax assets attributable to differences between book and tax basis of investment in project. A valuation allowance was not established against these deferred tax assets given the likelihood of realization.

7. Commitments and Contingencies

In the normal course of business, the Company is subject to various claims and litigation. Management of the Company expects that these various litigation items will not have a material adverse effect on the results of operations or financial position of the Company.

EXHIBIT 99.8

NRG INTERNATIONAL LLC

CONSOLIDATED FINANCIAL STATEMENTS

At June 30, 2004 and December 31, 2003, and for

the Three and Six Months Ended June 30, 2004 and 2003

NRG INTERNATIONAL LLC

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NRG INTERNATIONAL LLC

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 136,072	$ 127,020
Restricted cash	55,308	45,874
Accounts receivable	49,960	40,309
Accounts receivable — affiliates	6,285	5,404
Current portion of notes receivable	122,703	64,720
Inventory	17,000	17,900
Prepayments and other current assets	4,469	3,790
Current deferred income tax	700	754
Current assets — discontinued operations	—	12,615
Total current assets	392,497	318,386
Property, plant and equipment, net of accumulated depreciation of $13,002 and $1,467 respectively	418,810	458,224
Equity investments in affiliates	311,491	332,617
Notes receivable, less current portion	361,330	444,052
Notes receivable — affiliate	107,851	111,913
Derivative instruments valuation	46,070	59,907
Other assets	3,118	4,450
Noncurrent assets — discontinued operations	—	47,476
Total assets	$1,641,167	$1,777,025
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Current portion of long-term debt	$ 62,100	$ 75,944
Notes payable — affiliate	10,664	10,664
Accounts payable	27,253	30,271
Accounts payable — affiliate	3,909	2,976
Accrued income tax	7,938	18,673
Accrued liabilities	5,565	4,471
Other current liabilities	293	1,839
Current liabilities — discontinued operations	—	62,993
Total current liabilities	117,722	207,831
Other liabilities		
Long-term debt	224,800	266,526
Long-term debt — affiliates	193,889	198,300
Deferred income taxes	159,724	165,883
Postretirement and other benefit obligations	10,527	14,016
Derivative instruments valuation	101,209	112,047
Other long-term obligations	18,877	14,959
Noncurrent liabilities — discontinued operations	—	3,729
Total liabilities	826,748	983,291
Commitments and contingencies		
Member's equity	814,419	793,734
Total liabilities and member's equity	$1,641,167	$1,777,025

The accompanying notes are an integral part of these consolidated financial statements.

NRG INTERNATIONAL LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	For the Three Months Ended June 30,		For the Six Months Ended June 30	
	2004	2003	2004	2003
Revenues	**$ 70,062**	$ 68,557	**$ 167,344**	$ 146,511
Operating costs	**64,610**	59,442	**131,010**	122,728
Depreciation and amortization	**6,891**	4,769	**12,019**	8,487
General and administrative expenses	**1,850**	2,195	**5,265**	3,822
Income (loss) from operations	**(3,289)**	2,151	**19,050**	11,474
Equity in earnings of unconsolidated affiliates	**19,412**	9,131	**30,066**	25,855
Write downs and gains/(losses) on sales of equity method investments	**705**	(133,938)	**(1,268)**	(131,518)
Other income, net	**2,881**	1,384	**4,640**	2,977
Interest expense	**(3,430)**	(2,099)	**(5,619)**	(4,013)
Income (loss) from continuing operations before income taxes	**16,279**	(123,371)	**46,869**	(95,225)
Income tax expense	**589**	727	**7,450**	4,487
Income (loss) from continuing operations	**15,690**	(124,098)	**39,419**	(99,712)
Income on discontinued operations, net of income taxes	**9,475**	2,702	**7,517**	205,227
Net income (loss)	**$ 25,165**	$(121,396)	**$ 46,936**	$ 105,515

The accompanying notes are an integral part of these consolidated financial statements.

NRG INTERNATIONAL LLC

CONSOLIDATED STATEMENTS OF MEMBER'S EQUITY

(Unaudited)

	Member Units	Member Amount	Member Contributions/ Distributions	Accumulated Net Income (Loss)	Accumulated Other Comprehensive Income (Loss)	Total Member's Equity
Balances at March 31, 2003 (Predecessor Company)	1,000	$ 1	$ 942,795	$ (152,820)	$ (64,999)	$ 724,977
Net Loss				(121,396)		(121,396)
Foreign currency translation adjustments and other					64,554	64,554
Impact of SFAS No. 133 for the three months ended June 30, 2003, net of taxes of $5.4 million					23,074	23,074
Comprehensive loss						(33,768)
Contribution from member			7,641			7,641
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 950,436	$ (274,216)	$ 22,629	$ 698,850
Balances at March 31, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 771,256**	**$ 25,035**	**$ 23,621**	**$ 819,913**
Net Income				**25,165**		**25,165**
Foreign currency translation adjustments and other					**(30,325)**	**(30,325)**
Impact of SFAS No. 133 for the three months ended June 30, 2004, net of taxes of $1.5 million					**(334)**	**(334)**
Comprehensive loss						**(5,494)**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 771,256**	**$ 50,200**	**$ (7,038)**	**$ 814,419**
Balances at December 31, 2002 (Predecessor Company)	1,000	$ 1	$1,085,689	$ (379,731)	$ (55,350)	$ 650,609
Net Income				105,515		105,515
Foreign currency translation adjustments and other					89,445	89,445
Impact of SFAS No. 133 for the six months ended June 30, 2003, net of taxes of $16.1 million					(11,466)	(11,466)
Comprehensive income						183,494
Contribution from member			7,641			7,641
Distribution to member			(142,894)			(142,894)
Balances at June 30, 2003 (Predecessor Company)	1,000	$ 1	$ 950,436	$ (274,216)	$ 22,629	$ 698,850
Balances at December 31, 2003 (Reorganized Company)	**1,000**	**$ 1**	**$ 771,256**	**$ 3,264**	**$ 19,213**	**$ 793,734**
Net Income				**46,936**		**46,936**
Foreign currency translation adjustments and other					**(32,714)**	**(32,714)**
Impact of SFAS No. 133 for the six months ended June 30, 2004, net of taxes of $2.8 million					**6,463**	**6,463**
Comprehensive income						**20,685**
Balances at June 30, 2004 (Reorganized Company)	**1,000**	**$ 1**	**$ 771,256**	**$ 50,200**	**$ (7,038)**	**$ 814,419**

The accompanying notes are an integral part of these consolidated financial statements.

NRG INTERNATIONAL LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Reorganized Company	Predecessor Company
	For the Six Months Ended June 30,	
	2004	2003
Cash flows from operating activities		
Net income	**$ 46,936**	$ 105,515
Adjustments to reconcile net income to net cash provided by operating activities		
Distributions less than equity earnings of unconsolidated affiliates	**(19,252)**	(27,813)
Write downs and losses on sales of equity method investments	**1,268**	131,517
Depreciation and amortization	**12,019**	12,678
Unrealized (gains)/losses on derivatives	**1,418**	(8,063)
Unrealized exchange (gains)/losses	**(98)**	65
Deferred income taxes	**(894)**	20,982
Minority interest	**(43)**	(1,024)
Gain on sale of discontinued operations	**(10,280)**	(200,738)
Amortization of out of market power contracts	**19,070**	8,652
Changes in assets and liabilities		
Accounts receivable	**(11,249)**	(34,219)
Inventory	**(298)**	(1,743)
Prepayments and other current assets	**385**	(10,689)
Accounts payable	**(3,357)**	29,098
Accrued interest	**(3,406)**	(216)
Accrued income taxes	**(10,292)**	(1,991)
Accrued liabilities	**8,143**	(12,171)
Other liabilities	**—**	61,832
Net cash provided by operating activities	**30,070**	71,672
Cash flows from investing activities		
Investments in affiliates	**—**	(119)
Capital expenditures	**(5,872)**	(31,714)
Proceeds from sale of investments	**25,092**	38,400
Decrease in note receivable	**11,770**	63,677
Proceeds from sale of discontinued operations	**1,159**	—
Increase in restricted cash	**(13,405)**	(10,036)
Net cash provided by investing activities	**18,744**	60,208
Cash flows from financing activities		
Proceeds from issuance of debt	**14,311**	10,966
Contribution from member	**—**	7,641
Principal payments on long-term debt	**(48,294)**	(67,525)
Distribution to member	**—**	(142,894)
Net cash used in financing activities	**(33,983)**	(191,812)
Effect of exchange rate changes on cash and cash equivalents	**(6,501)**	(75,366)
Change in cash from discontinued operations	**722**	17,898
Net change in cash and cash equivalents	**9,052**	(117,400)
Cash and cash equivalents		
Beginning of period	**127,020**	192,862
End of period	**$ 136,072**	$ 75,462

The accompanying notes are an integral part of these consolidated financial statements.

NRG INTERNATIONAL LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Organization

NRG International LLC (the “Company”), a Delaware company incorporated on October 12, 1992, and converted to a limited liability company in November 2002, is a directly held, wholly owned subsidiary of NRG Energy, Inc. (“NRG Energy”).

The Company was formed for the purpose of financing, acquiring, owning, operating and maintaining, through its subsidiaries and affiliates, the power generation facilities owned by Flinders Power in Australia and Saale Energie GmbH in Germany. Flinders is a 760 MW power station and coal mine which sells electricity into the South Australian market. Saale Energie GmbH owns a 400 MW coal powered power station located in Halle Germany and sells output to Vattenfall Europe A.G. (“VEAG”) under a power purchase agreement

At June 30, 2004, the Company owned total interests in seven power projects in five countries having an aggregate generation capacity of approximately 2,075 MW in various international markets, including Australia, Europe and Latin America.

Recent Developments

On May 14, 2003, NRG Energy and 25 of its direct and indirect wholly owned subsidiaries commenced voluntary petitions under Chapter 11 of the bankruptcy code in the United States Bankruptcy Court for the Southern District of New York. During the bankruptcy proceedings, NRG Energy continued to conduct business and manage the companies as debtors in possession pursuant to sections 1107(a) and 1108 of the bankruptcy code. The Company was not part of these Chapter 11 cases or any of the subsequent bankruptcy filings. On November 24, 2003, the bankruptcy court entered an order confirming NRG Energy’s Plan of Reorganization and the plan became effective on December 5, 2003. In connection with NRG Energy’s emergence from bankruptcy, NRG Energy adopted fresh start accounting in accordance with AICPA Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code* (“SOP 90-7”) on December 5, 2003. NRG Energy’s fresh start accounting was applied to the Company on a push down accounting basis with the financial impact recorded as an adjustment to the December 6, 2003 member’s equity.

2. Summary of Significant Accounting Policies

Basis of Presentation

As used in these unaudited interim consolidated financial statements, “Predecessor Company” refers to the Company prior to NRG Energy’s emergence from bankruptcy. “Reorganized Company” refers to the Company after NRG Energy’s emergence from bankruptcy.

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with the Securities and Exchange Commission’s (“SEC”) regulations for interim consolidated financial information. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. The accounting policies followed are set forth in Note 2 to the Company’s annual audited consolidated financial statements for the year ended December 31, 2003. The following notes should be read in conjunction with such policies and other disclosures. 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 necessary to present fairly the Company’s consolidated financial position as of June 30, 2004 and December 31, 2003, the results of its operations and member’s equity for the three and six months ended June 30, 2004 and 2003 and the cash flows for the six months ended June 30, 2004 and 2003. Certain prior-year amounts have been reclassified for comparative purposes.

Comparability of Financial Information

Due to the adoption of push down accounting as of December 5, 2003, the Reorganized Company's consolidated balance sheet, statement of operations and statement of cash flows have not been prepared on a consistent basis with the Predecessor Company's financial statements and are not comparable in certain respects to the financial statements prior to the application of push down accounting. A black line has been drawn on the accompanying consolidated financial statements (excluding the balance sheet) to separate and distinguish between the Reorganized Company and the Predecessor Company.

3. Discontinued Operations

Statement of Financial Accounting Standards ("SFAS") No. 144 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, the Company's management considered cash flow analyses and offers related to those assets and businesses. This amount is included in income on discontinued operations, net of income taxes in the accompanying consolidated statements of operations. In accordance with the provisions of SFAS No. 144, assets held for sale will not be depreciated commencing with their classification as such.

The Company has 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 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.

For the three and six months ended June 30, 2004 discontinued operations included Hsin Yu. For the three and six months ended June 30, 2003, discontinued operations included Hsin Yu, Killingholme, Cahua and Energia Pacasmayo projects.

Summarized results of operations of discontinued operations were as follows:

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2004	2003	2004	2003
	(In thousands of dollars)			
Operating revenues	**$ —**	$ 19,259	**$ 8,266**	$ 57,225
Operating and other expenses	**805**	16,054	**11,113**	51,664
Pre-tax income/(loss) from operations of discontinued components	**(805)**	3,205	**(2,847)**	5,561
Income tax expense/(benefit)	**—**	660	**(84)**	511
Income/(loss) from operations of discontinued components	**(805)**	2,545	**(2,763)**	5,050
Disposal of discontinued components — gain, net of income tax expense	**10,280**	157	**10,280**	200,177
Net income on discontinued operations	**$ 9,475**	$ 2,702	**$ 7,517**	$ 205,227

The assets and liabilities of the discontinued operations are reported in the balance sheets as of December 31, 2003 as discontinued operations. All projects have been sold as of June 30, 2004. The major classes of assets and liabilities are presented in the following table and were included in the Power Generation Other International segment.

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Cash	$ —	$ 721
Receivables, net	—	5,121
Inventory	—	2,784
Other current assets	—	3,989
Current assets — discontinued operations	$ —	$ 12,615
Property, plant and equipment, net	$ —	$ 39,838
Other noncurrent assets	—	7,638
Noncurrent assets — discontinued operations	$ —	$ 47,476
Current portion of long-term debt	$ —	$ 40,820
Accounts payable — trade	—	16,401
Accrued interest	—	—
Other current liabilities	—	5,772
Current liabilities — discontinued operations	$ —	$ 62,993
Other long-term obligations	—	3,729
Noncurrent liabilities — discontinued operations	$ —	$ 3,729

Hsin Yu — During the second quarter 2004, the Company entered into an agreement to sell its interest in the Hsin Yu power generating facility (located in Taipei, Taiwan) to a minority interest shareholder, Asia Pacific Energy Development Company Ltd. The sale reached financial close in May 2004 and resulted in cash proceeds of $1.0 million and a gain of approximately $10.3 million resulting from the negative equity in the project. In addition, although the Company has no continuing involvement in the project, the Company retained the prospect of receiving $1.0 million in additional proceeds upon final closing of Phase II of the project.

Killingholme — During third quarter 2002, the Company recorded an impairment charge of $477.9 million. In January 2003, the Company completed the sale of its interest in the Killingholme project to its lenders for a nominal value and forgiveness of outstanding debt with a carrying value of approximately $360.1 million at December 31, 2002. The sale of the Company’s interest in the Killingholme project and the release of debt obligations resulted in a gain on sale in the first quarter of 2003 of approximately $201.0 million. The gain results from the write-down of the project’s assets in the third quarter of 2002 below the carrying value of the related debt.

Peru Projects — In November 2003, the Company completed the sale of the Cahua and Pacasmayo projects (Peruvian Assets) resulting in net cash proceeds of approximately $16.2 million and a loss of $36.9 million.

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

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

	Reorganized Company	Predecessor Company	Reorganized Company	Predecessor Company
	For the Three Months Ended June 30		For the Six Months Ended June 30	
	2004	2003	2004	2003
	(In thousands of dollars)			
Kondapalli	**$ —**	$ (1,812)	**$ —**	$ (517)
ECKG	**—**	(4,223)	**—**	(7,938)
Loy Yang	**(705)**	139,973	**1,268**	139,973
Total write downs and (gains)/losses on sales of equity method investments	**$ (705)**	$ 133,938	**$ 1,268**	$ 131,518

Lanco Kondapalli Power Pty Lty, or Kondapalli, — In the fourth quarter of 2002, the Company wrote down its investment in Kondapalli by $12.7 million due to recent estimates of sales value, which indicated an impairment of its book value that was considered to be other than temporary. On January 30, 2003, the Company signed a sales agreement with the Genting Group of Malaysia (“Genting”) to sell its 30% interest in Kondapalli, and a 74% interest in Eastern Generation Services (India) Pvt Ltd (the “O&M company”). Kondapalli is based in Hyderabad, Andhra Pradesh, India, and is the owner of a 368 MW natural gas fired combined cycle gas turbine. In the first quarter of 2003, the Company wrote down the investment in Kondapalli by $1.3 million based on the sales agreement. The sale closed on May 30, 2003 resulting in net cash proceeds of approximately $24.0 million and a gain of approximately $1.8 million, resulting in a net gain of $0.5 million. The gain resulted from incurring lower selling costs than estimated as part of the first quarter impairment.

ECKG — In September 2002, the Company announced that an agreement had been reached to sell its 44.5% interest in the ECKG power station in connection with the Csepel power generating facilities, and its interest in Entrade, an electricity trading business, to Atel, an independent energy group headquartered in Switzerland. The transaction closed in January 2003 and the Company received the final consideration adjustment in the second quarter of 2003. The sale resulted in cash proceeds of $65.3 million, including $46.8 million which was applied against notes receivable.

Loy Yang — The Company recorded an impairment charge of $111.4 million during 2002 and an additional impairment charge of $140.0 million during the second quarter of 2003 based on a third party market evaluation and bids received in response to marketing Loy Yang for possible sale. During the first quarter of 2004, the Company wrote down its investment in Loy Yang by $2.0 million due to recent estimates of the expected sales proceeds. In April 2004, the Company completed the sale of its 25% interest in Loy Yang to Great Energy Alliance Corporation, which resulted in net cash proceeds of $26.7 million and a loss of $1.3 million for the six months ended June 30, 2004.

5. Inventory

Inventory, which is valued at the lower of weighted average cost or market, consists of:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Fuel oil	$ 739	$ 504
Coal	9,601	10,726
Spare parts	6,660	6,670
Total inventory	$17,000	$ 17,900

6. Notes Receivable

Notes receivable consists primarily of fixed and variable rate notes secured by equity interests in partnerships and joint ventures. The notes receivable are as follows:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Notes receivables		
Termo Rio 19.5%	$ 57,323	$ 57,323
Notes receivable — nonaffiliates	57,323	57,323
Saale Energie GmbH, indefinite maturity date, 4.75%-7.79%	107,829	111,892
Other	22	21
Notes receivable — affiliates	107,851	111,913
Other		
Saale Energie GmbH, due August 31, 2021, 13.88% (direct financing lease)	426,710	451,449
Subtotal	591,884	620,685
Less: Current maturities	122,703	64,720
Total	$469,181	$ 555,965

The increase in current maturities at June 30, 2004 is due to the reclass of the Termo Rio Note Receivable to current.

7. Property, Plant and Equipment

The major classes of property, plant and equipment were as follows:

	Reorganized Company	
	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Facilities and equipment	$377,206	$ 323,837
Land and improvements	13,045	15,717
Office furnishings and equipment	3,053	2,081
Construction work in progress	38,508	118,056
Total property, plant and equipment	431,812	459,691
Accumulated depreciation	(13,002)	(1,467)
Property, plant and equipment, net	$418,810	$ 458,224

8. Investments Accounted for by the Equity Method

The Company had investments in various international energy projects. The equity method of accounting is applied to such investments in affiliates, which included joint ventures and partnerships, because the Company has significant influence over operating and financial policies of the projects. Under this method, equity in net income or losses of these projects, is reflected as equity in earnings of unconsolidated affiliates.

A summary of certain of the Company's more significant equity method investments, which were in operation at June 30, 2004, is as follows:

Name	Geographic Area	Economic Interest
Gladstone Power Station	Australia	38%
MIBRAG GmbH	Europe	50%
Enfield	Europe	25%
Scudder LA Power Fund I	Latin America	25%

In addition the Company had a 30% economic interest in Kondapalli, which was purchased in 2001 and sold in 2003; and a 25% economic interest in Loy Yang Power A purchased in 1997 and sold in 2004.

Summarized financial information for investments in unconsolidated affiliates accounted for under the equity method is as follows:

Results of Operations:

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2004	June 30, 2003	June 30, 2004	June 30, 2003
	(In thousands of dollars)			
Operating revenues	$162,949	$205,278	$351,096	$421,530
Operating income	$139,384	$169,047	304,692	363,630
Net income	$ 23,565	$ 36,531	$ 46,404	$ 57,900

Financial Position:

	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Current assets	$ 263,484	$ 369,800
Other assets	1,681,479	4,621,844
Total assets	1,944,963	4,991,644
Current liabilities	67,774	779,580
Other liabilities	1,323,116	3,524,886
Equity	554,073	687,178
Total liabilities and equity	$1,944,963	$4,991,644
The Company's share of equity	$ 228,921	$ 287,320
The Company's share of carrying value	311,491	332,617
The Company's share of net income (YTD)	30,066	1,707

The Company has ownership in two companies that were considered significant as of June 30, 2004, as defined by applicable SEC regulations, which are accounted for as equity method investments.

The following tables summarize financial information for Mibrag GmbH, of which the Company owns a 50% interest, including interests owned by the Company and other parties for the periods shown below:

Results of Operations:

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2004	June 30, 2003	June 30, 2004	June 30, 2003
	(In thousands of dollars)			
Operating revenues	$101,376	$97,098	$211,800	$188,430
Costs and expenses	11,468	8,402	31,128	22,824
Net income	11,008	13,920	23,072	28,930

Financial Position:

	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Current assets	$ 171,517	$ 164,780
Other assets	1,169,023	1,206,934
Total assets	$1,340,540	$1,371,714
Current liabilities	$ 22,025	$ 23,198
Other liabilities	981,489	1,031,606
Equity	337,026	316,910
Total liabilities and equity	$1,340,540	$1,371,714

The following tables summarize financial information for the Company's 37.5% interest in, and revenue and costs directly attributable to the Company's investment in Gladstone Power Station unincorporated joint venture.

Results of Operations:

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2004	June 30, 2003	June 30, 2004	June 30, 2003
	(In thousands of dollars)			
Operating revenues	$21,564	$17,773	$45,359	$34,879
Operating income	6,371	4,913	12,432	9,767
Net income	3,513	2,445	6,700	4,879

Financial Position:

	June 30, 2004	December 31, 2003
	(In thousands of dollars)	
Current assets	$ 31,919	$ 34,484
Other assets	197,036	215,472
Total assets	$228,955	$ 249,956
Current liabilities	$ 8,395	$ 22,970
Other liabilities	139,974	146,864
Equity	80,586	80,122
Total liabilities and equity	$228,955	$ 249,956

9. Asset Retirement Obligation

SFAS No. 143, *Accounting for Asset Retirement Obligations,* requires an entity to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred. Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes and written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The Company had previously recorded its asset retirement obligation and, as a result, the adoption of SFAS No. 143 on January 1, 2003 had no financial statement impact.

Upon the acquisition of Flinders Power in August 2000 (primarily the Northern Power Station, the Playford Power Station and the Leigh Creek mining operation), the Company recognized an obligation in the amount of $3.7 million as part of its opening balance sheet under purchase accounting related to an obligation to decommission these facilities at the end of their useful lives. Subsequently, the obligation has grown to $5.8 million at December 31, 2002, through periodic recognition of accretion expense.

The following represents the balances of the asset retirement obligation as of December 31, 2003 and related accretion for the six months ended June 30, 2004, which is included in other long-term obligations in the consolidated balance sheet.

	Beginning Balance December 31, 2003	Accretion for Six Months Ended June 30, 2004	Ending Balance June 30, 2004
		(In thousands of dollars)	
Australia	$ 9,438	$ 526	$9,964

10. Derivative Instruments and Hedging Activity

SFAS No. 133, *"Accounting For Derivative Instruments and Hedging Activities"*, as amended, requires the Company to record all derivatives on the consolidated balance sheet as assets or liabilities at fair value. For derivatives designated as cash flow hedges, the effective portion of the changes in fair value of the derivatives are recorded in Accumulated Other Comprehensive Income ("OCI") and subsequently recognized in earnings when the hedged items impact 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. Changes in the fair value of non-hedge derivatives will be immediately recognized in earnings.

SFAS No. 133 applies to the Company's long-term power sales contracts, long-term gas purchase contracts and other energy related commodities financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect investments in fuel inventories. SFAS No. 133 also applies to various interest rate financial instruments used to mitigate the risks associated with movements in interest rates, foreign exchange contracts used to reduce the effect of fluctuating foreign currencies on foreign denominated investments and other transactions.

Accumulated Other Comprehensive Income (OCI)

The following table summarizes the effects of SFAS No. 133 on the Company's OCI balance for the three months ended June 30, 2004:

Gains (Losses)	Energy Commodities	Interest Rate	Foreign Currency	Total
		(In thousands of dollars)		
Accumulated OCI balance at March 31, 2004	$ 5,654	$(1,304)	$ 296	$ 4,646
Unwound from OCI during period	—	—	—	—
Due to unwinding of previously deferred amounts	(2,753)	191	(296)	(2,858)
Mark-to market of hedge contracts	265	2,259	—	2,524
Accumulated OCI balance at June 30, 2004	$ 3,166	$ 1,146	$ —	$ 4,312
Gains (Losses) expected to unwind from OCI during next 12 months	$ 2,224	$ (230)	$ —	$ 1,994

The following table summarizes the effects of SFAS No. 133 on the Company's OCI balance for the six months ended June 30, 2004:

Gains (Losses)	Energy Commodities	Interest Rate	Foreign Currency	Total
		(In thousands of dollars)		
Accumulated OCI balance at December 31, 2003	$ (2,319)	$ 43	$ 125	$(2,151)
Unwound from OCI during period				—
Due to unwinding of previously deferred amounts	(1,729)	202	(296)	(1,823)
Mark-to market of hedge contracts	7,214	901	171	8,286
Accumulated OCI balance at June 30, 2004	$ 3,166	$1,146	$ —	$ 4,312
Gains (Losses) expected to unwind from OCI during next 12 months	$ 2,224	$ (230)	$ —	$ 1,994

Gains of $2.8 million and $1.8 million were reclassified from OCI to current period earnings during the three and six months ended June 30, 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 and six months ended June 30, 2004, the Company recorded gains in OCI of approximately $2.5 million and $8.3 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 at June 30, 2004, was an unrecognized gain of approximately $4.3 million. The Company expects $2.0 million of deferred net gains 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 nonhedge derivatives and derivatives that no longer qualify as hedges on the Company's statement of operations for the three months ended June 30, 2004:

	Reorganized NRG		
	Energy Commodities	Interest Rate	Total
		(In thousands of dollars)	
Revenue from majority-owned subsidiaries	$ 1,057	$ —	$ 1,057
Equity in earnings of unconsolidated subsidiaries	9,733	560	10,293
Total statement of operations impact before tax	$ 10,790	$ 560	$11,350

The following table summarizes the pre-tax effects of nonhedge derivatives and derivatives that no longer qualify as hedges on the Company's statement of operations for the six months ended June 30, 2004:

	Reorganized NRG		
	Energy Commodities	Interest Rate	Total
		(In thousands of dollars)	
Revenue from majority-owned subsidiaries	$ 1,654	$ —	$ 1,654
Equity in earnings of unconsolidated subsidiaries	8,506	629	9,135
Total statement of operations impact before tax	$ 10,160	$ 629	$10,789

The following table summarizes the pre-tax effects of nonhedge derivatives and derivatives that no longer qualify as hedges on the Company's statement of operations for the three months ended June 30, 2003:

	Predecessor NRG		
	Energy Commodities	Interest Rate	Total
	(In thousands of dollars)		
Revenue from majority owned subsidiaries	$ —	$ —	$ —
Equity in earnings of unconsolidated subsidiaries	2,187	(29)	2,158
Cost of operations	3,759	—	3,759
Total statement of operations impact before tax	$ 5,946	$ (29)	$5,917

The following table summarizes the pre-tax effects of nonhedge derivatives and derivatives that no longer qualify as hedges on the Company's statement of operations for the six months ended June 30, 2003:

	Predecessor NRG		
	Energy Commodities	Interest Rate	Total
	(In thousands of dollars)		
Equity in earnings of unconsolidated subsidiaries	$ 3,731	$(289)	$ 3,442
Cost of operations	(5,298)	—	(5,298)
Total statement of operations impact before tax	$ (1,567)	$(289)	$(1,856)

Energy Related Commodities

The Company is exposed to commodity price variability in electricity and natural gas, oil and coal used to meet fuel requirements. In order to manage these commodity price risks, the Company enters into financial instruments, which may take the form of fixed price, floating price or indexed sales or purchases, and options, such as puts, calls, basis transactions and swaps. Certain of these transactions have been designated as cash flow hedges. The Company has accounted for these derivatives by recording the effective portion of the cumulative gain or loss on the derivative instrument as a component of OCI in member's equity. The Company recognized deferred gains and losses into earnings in the same period or periods during which the hedged transaction affects earnings. Such reclassifications are included on the same line of the statement of operations in which the hedged item is recorded.

No ineffectiveness was recognized on commodity cash flow hedges during the three and six months ended June 30, 2004 and 2003.

The Company's pre-tax earnings for the three and six months ended June 30, 2004 and 2003, were affected by an unrealized gain of $10.8 million and $10.2 million, respectively, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

The Company's pre-tax earnings for the three and six months ended June 30, 2003, were affected by an unrealized gain of $5.9 million and an unrealized loss of $1.6 million, respectively, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

During the three and six months ended June 30, 2004, the Company reclassified gains of $2.8 million and $1.7 million, respectively, from OCI to current-period earnings and expects to reclassify an additional $2.2 million of deferred gains to earnings during the next twelve months on energy related derivative instruments accounted for as hedges.

At June 30, 2004, the Company had hedge and nonhedge energy related commodities financial instruments extending through September 2018.

Interest Rates

To manage interest rate risk, the Company has entered into interest-rate swap agreements that fix the interest payments of certain floating rate debt issuances. The qualifying swap agreements are accounted for as cash flow hedges. The effective portion of the cash flow hedges' cumulative gains/losses are reported as a component of OCI in member's equity. These gains/losses are recognized in earnings as the hedged interest expense is incurred. The reclassification from OCI is included on the same line of the statement of operations in which the hedged item appears.

No ineffectiveness was recognized on interest rate swaps that qualify as hedges during the three and six months ended June 30, 2004.

During the three and six months ended June 30, 2004, pre-tax earnings were increased by an unrealized gain of $0.6 million and $0.6 million, respectively, associated with the changes in the fair value of the interest rate derivative instruments not accounted for as hedges in accordance with SFAS No. 133. The Company's pre-tax earnings for the three and six months ended June 30, 2003, were decreased by an unrealized loss of $0 and $0.3 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.

During the three and six months ended June 30, 2004, the Company reclassified losses of $0.2 million from OCI to current-period earnings and expect to reclassify approximately $0.2 million of deferred losses to earnings during the next twelve months associated with interest rate swaps accounted for as hedges.

At June 30, 2004, the Company had interest rate derivatives instruments extending through December 2017.

Foreign Currency Exchange Rates

To preserve the U.S. dollar value of projected foreign currency cash flows, the Company may hedge, or protect those cash flows if appropriate foreign hedging instruments are available.

No ineffectiveness was recognized on foreign currency cash flow hedges during the three and six months ended June 30, 2004.

During the three and six months ended June 30, 2004, the Company reclassified gains of $0.3 million from OCI to current-period earnings and the Company does not expect to reclassify any deferred gains/losses to earnings during the next twelve months on foreign currency swaps accounted for as hedges.

11. Long-Term Debt and Capital Leases

Long-term debt and capital leases consist of the following:

			Reorganized Company			
			June 30, 2004		December 31, 2003	
	Stated Rate	Effective Rate	Principal	Fair Value Adjustment	Principal	Fair Value Adjustment
	Percent		(In thousands of dollars)			
Flinders Power Partnership September 2012	(1)	6%	$184,356	$ 9,533	$187,668	$ 10,632
NRG International Inc.	—	(2)	10,664	—	10,664	—
Long-term debt — affiliates			195,020	9,533	198,332	10,632
Saale Energie GmbH, Schkopau capital lease, due 2021	11%	11%	286,900	—	342,470	—
Long-term debt — nonaffiliates			286,900	—	342,470	—
			481,920	9,533	540,802	10,632
Less: Current maturities			72,764	—	86,608	—
			$409,156	$ 9,533	$454,194	$ 10,632

(1) Rate is at 6-month LIBOR plus .5%.

(2) Non interest bearing

At June 30, 2004, the Company has timely made scheduled payments on interest and/or principal on all of its debt and was not in default under any of the Company's debt instruments.

In December 2003, the Company entered into a note payable in the amount of $10.7 million with NRGenerating Holdings No. 21 BV, an indirect wholly owned subsidiary of NRG Energy and an affiliate of the Company, in connection with the sale of the Company's 100% ownership interest in Sterling Luxembourg (No. 4) S.a.a.L. (see Note 16 — Related Party Transactions). The note is payable on demand.

Project Financings

Flinders Power

In September 2000, Flinders Power Finance Pty Ltd ("Flinders Finance") an indirect wholly owned subsidiary of NRG Energy and an affiliate of the Company, entered into a twelve-year AUD$150 million cash advance facility (US$81.4 million at September 2000). At June 30, 2004 and December 31, 2003, there remains AUD$127.0 million (US$88.8 million) and AUD$135.0 million (US$101.6 million) outstanding under this facility, respectively. The interest has a fixed margin and variable base component. At June 30, 2004 and December 31, 2003, the interest rates were 7.50% and 7.53%, respectively. Ordinarily, interest is paid semi-annually at the end of June and December. Principal payments commence in 2006 and the facility will be fully paid in 2012.

In March 2002, Flinders Finance entered into a ten-year AUD$165 million (US$85.4 million at March 2002) floating rate loan facility for the purpose of refurbishing the Flinders Playford generating station. At June 30, 2004 and December 31, 2003, the Company had drawn AUD$136.6 million (US$95.5 million) and AUD$114.3 million (US$86.0 million), respectively, of this facility. The interest rate has a fixed margin and variable base component. The interest rates at June 30, 2004 and December 31, 2003, were 7.00% and 7.03%, respectively. Ordinarily interest is paid semi-annually, at the end of June and December. Principal payments for the refurbishment facility commence in 2005. Upon the Company's downgrades in 2002, there existed a potential default under these facility agreements related to the funding of reserve accounts. On May 13, 2003, Flinders Finance and its lenders entered into a Second Supplemental Deed, which resolved these potential defaults. As part of the terms of that Second Supplemental Deed, part of the refurbishment facility was voluntarily cancelled by Flinders Finance so as to reduce the total available commitment from AUD$165 million to AUD$137 million (US$103.1 million).

In addition, Flinders Finance has an AUD$20 million (US$15 million) working capital facility, of which AUD$11.2 million (US$8.2 million) is reserved as support for potential calls on performance guarantees. Nothing has been drawn under this facility at June 30, 2004 and December 31, 2003.

All drawn funds under the above mentioned facilities and bank loans are lent to Flinders Power by Flinders Finance through project loan agreements. The terms and conditions are identical to the agreements with the third parties.

Saale Energie GmbH

In connection with the purchase of PowerGen's (third party owner) interest in Saale Energie GmbH, the Company has recognized a nonrecourse capital lease on the consolidated balance sheet in the amount of $286.9 million and $342.5 million, as of June 30, 2004 and December 31, 2003, respectively. The capital lease obligation is recorded at the net present value of the minimum lease obligation payable over the lease's remaining period of 19 years. In addition, a direct financing lease was recorded in notes receivable in the amount of approximately $426.7 million and $451.4 million as of June 30, 2004 and December 31, 2003, respectively.

12. Segment Reporting

The Company conducts its business within two reportable operating segments — Power Generation Australia and Power Generation — Europe. These reportable segments are distinct components with separate operating results and management structures in place. Segment information for the three and six months ended June 30, 2004 and 2003 is as follows.

For the three months ended June 30, 2004:

	Reorganized Company Power Generation		
	Australia	Europe	Total
	(In thousands of dollars)		
Operations			
Operating revenues	$ 29,271	$ 40,791	$ 70,062
Operating costs	32,354	32,256	64,610
Depreciation and amortization	6,868	23	6,891
General and administrative expenses	701	1,149	1,850
Other income	1,405	1,476	2,881
Interest (expense)	(2,546)	(884)	(3,430)
Equity in earnings in unconsolidated affiliates	3,534	15,878	19,412
Write downs and gains/(losses) on sales of equity method investments	705	—	705
Income tax expense (benefit)	(3,250)	3,839	589
Net income (loss) from continuing operations	(4,304)	19,994	15,690
Net income from discontinued operations	—	9,475	9,475
Net income (loss)	(4,304)	29,469	25,165
Balance sheet			
Investment in projects	$ 98,874	$212,617	$ 311,491
Total assets	654,879	986,288	1,641,167

For the three months ended June 30, 2003:

	Predecessor Company Power Generation		
	Australia	Europe	Total
	(In thousands of dollars)		
Operations			
Operating revenues	$ 34,537	$34,020	$ 68,557
Operating costs	33,481	25,961	59,442
Depreciation and amortization	4,729	40	4,769
General and administrative expenses	653	1,542	2,195
Other income	519	865	1,384
Interest (expense)	(1,855)	(244)	(2,099)
Equity in earnings in unconsolidated affiliates	346	8,785	9,131
Write downs and gains/(losses) on sales of equity method investments	(139,973)	6,035	(133,938)
Income tax expense (benefit)	(1,706)	2,433	727
Net income/(loss) from continuing operations	(143,583)	19,485	(124,098)
Net income from discontinued operations	—	2,702	2,702
Net income/(loss)	(143,583)	22,187	(121,396)

For the six months ended June 30, 2004:

	Reorganized Company Power Generation		
	Australia	Europe	Total
	(In thousands of dollars)		
Operations			
Operating revenues	$100,025	$ 67,319	$ 167,344
Operating costs	79,587	51,423	131,010
Depreciation and amortization	12,011	8	12,019
General and administrative expenses	1,718	3,547	5,265
Other income	1,641	2,999	4,640
Interest (expense)	(4,451)	(1,168)	(5,619)
Equity in earnings in unconsolidated affiliates	6,706	23,360	30,066
Write downs and losses on sales of equity method investments	(1,268)	—	(1,268)
Income tax expense	118	7,332	7,450
Net income from continuing operations	9,219	30,200	39,419
Net income from discontinued operations	—	7,517	7,517
Net income	9,219	37,717	46,936
Balance sheet			
Investment in projects	$ 98,874	$212,617	$ 311,491
Total assets	654,879	986,288	1,641,167

For the six months ended June 30, 2003:

	Predecessor Company Power Generation		
	Australia	Europe	Total
	(In thousands of dollars)		
Operations			
Operating revenues	$ 82,669	$ 63,842	$ 146,511
Operating costs	73,088	49,640	122,728
Depreciation and amortization	8,413	74	8,487
General and administrative expenses	851	2,971	3,822
Other income	2,299	678	2,977
Interest expense	(424)	(3,589)	(4,013)
Equity in earnings in unconsolidated affiliates	7,473	18,382	25,855
Write downs and gains/(losses) on sales of equity method investments	(139,973)	8,455	(131,518)
Income tax expense (benefit)	(1,129)	5,616	4,487
Net income (loss) from continuing operations	(129,179)	29,467	(99,712)
Net income from discontinued operations	—	205,227	205,227
Net income	(129,179)	234,694	105,515

13. Income Taxes

Segments of the Company are included in the consolidated tax return filings as a wholly owned subsidiary of NRG Energy. Reflected in the financial statements and note below are separate company federal, state, and international tax provisions as if the company had prepared separate filings. An income tax provision has been established on the accompanying financial statements as of the earliest period presented in order to reflect income taxes as if the Company filed its own tax return. The Company's parent, NRG Energy, does not have a tax allocation agreement with its subsidiaries nor has it historically pushed down or allocated income taxes to non tax paying entities or entities such as the Company which are treated as disregarded entities for tax purposes.

The Company operates in various international jurisdictions through its subsidiaries and affiliates and incurs income tax liabilities (assets) under the applicable local tax laws and regulations.

Income taxes for the six months ended June 30, 2004, was a tax expense of $7.5 million compared to a tax expense of $4.5 million for the same period in 2003. The tax expense for the six months ended June 30, 2004 and 2003, includes only international taxes. U.S. deferred tax assets from net operating loss carryforwards and other timing differences are offset in full by a valuation allowance resulting in no net U.S. tax expense.

Income taxes for the three months ended June 30, 2004 was a tax expense of $0.7 million compared to a tax expense of $0.8 million for the same period in 2003. The tax expense for the three months ended June 30, 2004 and 2003, includes only international taxes. U.S. deferred tax assets from net operating loss carryforwards and other timing differences are offset in full by a valuation allowance resulting in no net U.S. tax expense.

The tax expense for the three and six months ended June 30, 2004, is due to current and deferred taxes payable on the earnings in certain international jurisdictions including withholding taxes on certain types of earnings. Due to the uncertainty of realization of deferred tax assets related to net operating losses and other temporary differences, the U.S. and foreign deferred tax assets of $94.7 million at June 30, 2004, were offset by a valuation allowance of $6.4 million in accordance with SFAS No. 109. The Company's deferred tax liabilities at June 30, 2004, were $247.3 million resulting in net deferred tax liabilities of $159.0 million. For 2003, the tax expense is due to current and deferred taxes payable on earnings under the local income tax laws and regulations in certain international jurisdictions including withholding taxes on certain types of earnings. The Company's deferred tax assets at December 31, 2003, were $366.5 million offset by a valuation allowance of $156.5 million. The Company's deferred tax liabilities at December 31, 2003, were $375.1 million resulting in net deferred tax liabilities of $165.1 million.

The effective income tax rate for the period ended June 30, 2004 and 2003, differs from the statutory federal income tax rate of 35% primarily due to lower tax rates in foreign jurisdictions.

As of June 30, 2004, the valuation allowance against U.S. and foreign net operating loss carryforwards was $4.9 million and the valuation allowance against other deferred tax assets was $1.5 million. As of December 31, 2003, a valuation allowance of $155.0 million was provided to account for potential limitations on utilization of U.S. and foreign net operating loss carryforwards, and a valuation allowance of $1.5 million was provided for other deferred tax assets. Net operating loss carryforwards for foreign purposes have no expiration date.

As of June 30, 2004, NRG Energy's management intends to indefinitely reinvest the earnings of foreign operations except to the extent the earnings are not subject to current U.S. income taxes. Accordingly, U.S. income taxes and foreign withholding taxes have not been provided on a cumulative amount of losses of $340.5 million at June 30, 2004, and $387.5 million at December 31, 2003.

14. Commitments and Contingencies

Legal Issues

Matra Powerplant Holding B.V.

Matra Powerplant Holding B.V. (“Matra”) is presently involved in a dispute with the Dutch tax commissioner. For the tax years from 1998 until 2001, NRGenerating International B.V. indirectly (through Kladno Power (No. 2) B.V. and Entrade Holdings B.V.) held 50% of the issued and outstanding shares in the capital of Matra. The shareholders of Matra granted interest-free loans to Matra in reliance upon a favorable tax ruling granted to NRGenerating International B.V. in 1994.

The tax commissioner now has asserted that the loans constitute capital contributions (so-called shareholders’ loans) and thereby has challenged the imputed interest deductions of Matra in the subsequent years.

Accordingly, the tax commissioner has issued the following statutory notices of deficiency (“SND”) and tax assessments (“TA”):

1998 SND	Corporate Income Tax 35%	EUR518,723
1998 SND	Capital Duty 1%	EUR615,179
2001 TA	Corporate Income Tax 35%	EUR1,702,349

The Company has filed appeals against the SND and TA. For the 1998 corporate income tax SND, the tax commissioner has to prove that a new fact justifies the SND. This is not required for the 1998 capital duty SND or the 2001 corporate income TA. At this time, the Company cannot estimate the likelihood of success regarding these claims.

Threatened claims against the Company’s subsidiaries relating to the funding of several projects, realized by way of (informal) capitalization

The Dutch tax commissioner has asserted that the capitalization of some of the Company’s subsidiaries was basically intended to avoid capital duty in The Netherlands, which could constitute abuse of law (“fraus legis”). In the Company’s correspondence with the tax commissioner, the Company made clear that there were other substantial commercial reasons to use these specific structures, including avoidance of currency exchange gains and/or capital duty in Luxembourg and/or other reasons.

The tax commissioner has not yet responded to the Company’s latest response sent to the commission on May 21, 2001.

The threatened respective amounts of capital duty are:

(a) NRGenerating International B.V.: AUD $3,784,670, AUD $1,569,366, UK pounds 1,080,000 and UK pounds 155,294;

(b) NRGenerating Holdings (No. 15) B.V.: UK pounds 900,000; and

(c) NRGenerating Holdings (No. 20) B.V.: US$1.

No prediction of the likelihood of an unfavorable outcome can be made at this time.

NRGenerating Holdings (No. 4) B.V. and Gunwale B.V.

In the years 1999 and 2000, Gunwale B.V. was part of a transaction intended to recapitalize NRGenerating Holdings (No. 4) B.V. The Company has asserted that these transactions were structured so as to mitigate currency exchange risk and for other substantial commercial reasons. The tax commissioner has issued statutory notices of deficiency for both NRGenerating Holdings (No. 4) B.V. and Gunwale B.V., arguing that asserted exemptions do not apply and that duty should have been paid under prevailing law. The threatened amount of capital duty due would amount to approximately EUR 235,943 for the year 1999 and EUR 1,325,334 for the year 2000.

Objections to these notices have been filed by Dutch counsel for the buyer, Grant Energy Alliance Corporation, of NRGenerating Holdings (No. 4) B.V. and Gunwale B.V.

Although both companies were sold in April 2004 as part of the sale of Loy Yang, and therefore are no longer held by any of the Company's affiliates, under the share sale agreement, the Company still could become indirectly liable for the subject capital duty, should the buyer exercise a put-option for a predetermined price respective to the shares in Gunwale B.V.

Matra Powerplant Holding B.V.

The Dutch tax commissioner appears to have treated Matra's taxable income for 1999 in a manner inconsistent with the commissioner's treatment of Matra's taxable income for 1998 and 2001, as referenced above. In the event the commissioner were to later assert that it clearly erred in its 1999 treatment, the commissioner could issue a new SND, subject to demonstrating that the taxpayer should have been aware of this error and the existence of a new fact to support the new SND. Should the tax commissioner issue a new SND for 1999, the Company believes the assessment could exceed US$1.2 million.

Flinders Refurbishment Project

Flinders Power Partnership ("Flinders") is engaged in a dispute with Alstom Power Limited ("Alstom"), the contractor engaged to provide turnkey refurbishment of the Playford B Power Station. Flinders assert that, pursuant to the Turnkey Refurbishment Contract, Alstom owes Flinders substantial liquidated damages for failing to timely achieve certain project completion milestones. Flinders has set-off some AUD$13 million of those liquidated damage amounts against Alstom's progress invoices, and asserts a further claim for liquidated damages, availability guarantee payments and other items totaling some additional AUD$23 million. Alstom disputed Flinders' entitlement to liquidated damages and commenced court proceedings, asserting that Flinders owes it approximately AUD$25 million beyond what Flinders has already paid. By mutual agreement, those proceedings have been adjourned while the parties attempt to mediate the dispute. No prediction of the likelihood of an unfavorable outcome can be made at this time.

Contractual Commitments

Flinders Power

Upon the acquisition of Flinders Power in August 2000, the South Australian Government assigned money losing contracts with Osborne Power Plant ("OCPL") to Flinders Power. The Osborne plant has a nameplate capacity of 180 MW, notionally comprising baseload capacity of 134 MW, surplus baseload capacity of 7 MW and peaking capacity of 39 MW. Under its power purchase agreement with the owner of the OCPL, Flinders Power purchases electricity from OCPL and bids that electricity into the National Electricity Market ("NEM"). Under a separate gas sale agreement, Flinders Power also supplies OCPL with gas. Flinders Power is supplied with that gas under a contract with Terra Gas Trader ("TGT"). These contracts are derivatives that do not qualify for hedge accounting treatment in accordance with SFAS No. 133. See Note 10 — Derivative Instruments and Hedging Activities.

TGT is owned by Tarong Energy (a Queensland Government owned corporation). Both Flinders Power's purchases of electricity from OCPL and supply of gas to OCPL are at a loss. These contracts are accounted for as derivatives and reflected accordingly in the consolidated financial statements of the Company.

15. Guarantees

In November 2002, the FASB issued FASB Interpretation No. ("FIN") 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others.* The initial recognition and initial measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year end. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. The interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. The interpretation also clarifies the requirements related to the recognition of a liability by a guarantor at the inception of the guarantee for the obligations the guarantor has undertaken in issuing the guarantee.

In connection with the application of push down accounting, all outstanding guarantees were considered new; accordingly, the Company applied the provisions of FIN 45 to all of those guarantees. Each guarantee was reviewed for the requirement to recognize a liability at inception. As a result, the Company was not required to record any liabilities.

On December 23, 2003, the Company's parent, NRG Energy, issued $1.25 billion of 8% Second Priority Notes, due and payable on December 15, 2013. On January 28, 2004, NRG Energy also issued $475.0 million of Second Priority Notes, under the same terms and indenture as its December 23, 2003 offering.

NRG Energy's payment obligations under the notes and all related Parity Lien Obligations are guarantees on an unconditional basis by each of NRG Energy's current and future restricted subsidiaries, of which the Company is one. The notes are jointly and severally guaranteed by each of the guarantors. The subsidiary guarantees of the notes are secured, on a second priority basis, equally and ratably with any future parity lien debt, by security interest in all of the assets of the guarantors, except certain excluded assets, subject to liens securing parity lien debt and other permitted prior liens.

The Company's obligations pursuant to its guarantees of the performance, equity and indebtedness obligations were as follows:

	Guarantee/ Maximum Exposure	Nature of Guarantee	Expiration Date	Triggering Event
	(In thousands of dollars)			
NRG Energy Second Priority Notes due 2013	$1,753,000	Obligations under credit agreement	2013	Nonperformance

16. Related Party Transactions

In December 2003, the Company sold 100% of its outstanding shares of Sterling Luxembourg (No. 4) S.a.r.L. ("Sterling") which held an interest in Itiquira S.A., COBEE, Flinders Finance and several dormant holding companies. Fifty percent of the total outstanding shares of Sterling were sold to NRG Latin America, Inc., a wholly owned subsidiary of NRG Energy and an affiliate of the Company, for $3 million, satisfied through a reduction of NRG Latin America, Inc.'s receivable from the Company. The remaining 50% of the total outstanding shares were sold to NRG Energy for $3 million, which consisted of a dividend distribution of one dollar, plus settlement of a payable to NRG Energy of $3 million. As part of this transfer of assets to affiliates, the Company entered into a note payable in the amount of $10.7 million with NRGenerating Holdings No. 21 BV, an indirect wholly owned subsidiary of NRG Energy and an affiliate of the Company. See Note 11 — Long Term Debt and Capital Leases.

In accordance with SFAS No. 141, *Business Combinations*, because the transfer was between entities under common control, the provisions of APB Opinion No. 16, *Business Combinations*, applied. Therefore all activity related to the entities that were sold was removed from the financial statements of NRG International LLC as presented herein.