UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K/ A

Amendment No. 3

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year ended December 31, 2003.

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from to .

Commission File No. 001-15891

NRG Energy, Inc.

(Exact name of Registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**41-1724239** *(I.R.S. Employer Identification No.)*
211 Carnegie Center **Princeton, New Jersey** *(Address of principal executive offices)*	**08540** *(Zip Code)*

(609) 524-4500

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
None	None

Securities registered pursuant to Section 12(g) of the Act:

Common Stock, par value $0.01 per share

Indicate by check mark whether the Registrant (1) has filed all reports to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter 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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is an accelerated filer as defined by Rule 12b-2 of the Act. Yes ☑ No ☐

As of the last business day of the most recently completed second fiscal quarter, the aggregate market value of the common stock of the registrant held by non-affiliates was approximately $1,943,806,466.

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 Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☑ No ☐

Indicate the number of shares outstanding of each of the registrant's classes of common stock as of the latest practicable date.

Class	Outstanding at December 3, 2004
Common Stock, par value $0.01 per share	100,008,053

Documents Incorporated by Reference:

None

NRG ENERGY, INC. AND SUBSIDIARIES

INDEX

We are reissuing our audited financial statements for the year ended December 31, 2003 as Amendment No. 3 on Form 10-K/A. The updated information includes 2004 discontinued operations as described in Note 6. Discontinued operations have been updated to include four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC). These are in addition to the entities included in Amendment No. 2, filed on November 3, 2004, which relate to the sale of our interests in Penobscot Energy Recovery Company, Compania Boliviana De Energia Electrica S.A. — Bolivian Power Company Limited, LSP Energy and Hsin Yu.

Item 6 — *Selected Financial Data*

The following table presents our selected financial data. The data included in the following table has been restated to reflect the assets, liabilities and results of operations of certain projects that have met the criteria for treatment as discontinued operations. For additional information refer to Item 15 — Note 6 to the Consolidated Financial Statements. This historical data should be read in conjunction with the Consolidated Financial Statements and the related notes thereto in Item 15 and "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7. Due to the adoption of Fresh Start reporting as of December 5, 2003, the Successor Company's post Fresh Start balance sheet and statement of operations 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 reporting. A black line has been drawn to separate and distinguish between Reorganized NRG and the Predecessor Company.

	Predecessor Company					Reorganized NRG
	Year Ended December 31,				January 1 - December 5,	December 6 - December 31,
	1999	2000	2001	2002	2003	2003
	(In thousands, except per share amounts)					
Revenues from majority-owned operations	$ 418,590	$1,664,980	$ 2,085,350	$ 1,938,293	$ 1,798,387	**$ 138,490**
Legal settlement	—	—	—	—	462,631	**—**
Fresh start reporting Adjustments	—	—	—	—	(4,118,636)	**—**
Reorganization, restructuring and impairment charges	—	—	—	2,563,060	435,400	**2,461**
Total operating costs and Expenses	368,714	1,308,589	1,703,531	4,321,385	(1,475,523)	**122,328**
Write downs and losses on equity method investments	—	—	—	(200,472)	(147,124)	**—**
Income/(loss) from continuing operations	52,960	149,729	210,502	(2,788,452)	2,949,078	**11,405**
Income/(loss) from discontinued operations, net	4,235	33,206	54,702	(675,830)	(182,633)	**(380)**
Net income/(loss)	57,195	182,935	265,204	(3,464,282)	2,766,445	**11,025**
Net income per weighted Average share—basic						**$ .11**
Net income per weighted Average share—diluted						**$ .11**
Total assets	3,435,304	5,986,401	12,922,385	10,896,851	N/A	**9,244,987**
Long-term debt, including current maturities	$1,705,634	$3,194,322	$ 6,857,055	$ 7,782,648	N/A	**$4,129,011**

N/A — Not Applicable.

The following table provides the detail of our revenues from majority-owned operations:

	Predecessor Company					Reorganized NRG
	Year Ended December 31,				January 1 - December 5, 2003	December 6 - December 31, 2003
	1999	2000	2001	2002		
	(In thousands, except per share amounts)					
Energy and energy related	$ 3,292	$1,091,115	$1,376,044	$1,183,514	$ 992,626	**$ 78,018**
Capacity	4,288	405,697	490,315	553,321	565,965	**39,955**
Alternative energy	83,343	92,671	161,845	97,712	115,911	**12,064**
O&M Fees	9,502	10,073	15,789	14,413	12,942	**1,135**
Other	318,165	65,424	41,357	89,333	110,943	**7,318**
Total revenues from majority-owned operations	$418,590	$1,664,980	$2,085,350	$1,938,293	$1,798,387	**$ 138,490**

Energy and energy related revenue consists of revenues received upon the physical delivery of electrical energy to a third party at both spot (merchant sales) and contracted rates. In addition, we also generate revenues from the sale of ancillary services and by entering into certain financial transactions. Ancillary revenues are derived from the sale of energy related products associated with the generation of electrical energy such as spinning reserves, reactive power and other similar products. Revenues derived from financial transactions are generally received upon the settlement of transactions relating to the sale of energy or fuel which do not require the physical delivery of the underlying commodity.

Capacity revenue consists of revenues received from a third party at either spot (merchant sales) or negotiated contract rates for making installed generation capacity available upon demand in order to satisfy system integrity and reliability requirements. In addition, capacity revenues includes revenues received under tolling arrangements which entitle third parties to dispatch our facilities and assume title to the electrical generation produced from that facility.

Alternative energy revenue consists of revenues received from the sale of steam, hot and chilled water generally produced at a central district energy plant and sold to commercial, governmental and residential buildings for space heating, domestic hot water heating and air conditioning. Alternative energy revenue includes the sale of high-pressure steam produced and delivered to industrial customers that is used as part of an industrial process. In addition, alternative revenue includes revenues received from the processing of municipal solid waste into refuse derived fuel that is sold to a third party to be used as fuel in the generation of electricity.

O&M fees consist of revenues received from providing certain unconsolidated affiliates with management and operational services generally under long-term operating agreements.

Other revenues consist of miscellaneous other revenues derived from the sale of natural gas, recovery of incurred costs under reliability agreements and revenues received under leasing arrangements.

Item 7 — *Management's Discussion and Analysis of Financial Condition and Results of Operations*

Overview

We are 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, which help us, mitigate risk. We intend 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.

Our focus will continue to be on the operating performance of our entire portfolio and, in particular, on developing the assets in our core regions into integrated businesses well-suited to serving the requirements of the load-serving entities in our core markets. Power sales, fuel procurement and risk management will remain a key strategic element of these regional businesses contributing to our overall objective to optimize the operating income generated by all of our facilities within an appropriate risk and liquidity profile. Our business will involve the reinvestment of capital in our existing assets for reasons of life extension, repowering, expansion, environmental remediation, operating efficiency, greater fuel optionality or for alternative use, among other reasons. Our business also may involve select acquisitions intended to complement and enhance the commercial performance of the asset portfolios in our core regions.

Industry Trends. In this "Management's Discussion and Analysis of Financial Condition and Results of Operations," we discuss our historical results of operations and expected financial condition. During 2002 and 2003, the following factors, among others, have negatively affected our results of operations:

- weak markets for electric energy, capacity and ancillary services;
- a narrowing of the "spark spread" (the difference between power prices and fuel costs) in most regions of the United States in which we operate power generation facilities offset by our coal-fired assets, which gain a competitive advantage when gas prices rise;
- mild weather during peak seasons in regions where we have significant merchant capacity;
- reduced liquidity in the energy trading markets as a result of fewer participants trading lower volumes;
- the imposition of price caps and other market mitigation in markets where we have significant merchant capacity;
- regulatory and market frameworks in certain regions where we operate that prevent us from charging prices that will enable us to recover our operating costs and to earn acceptable returns on capital; however, we benefited from the FERC acceptance of certain RMR agreements subject to refund;
- the obligation through 2003 to perform under certain long-term contracts that are not profitable;
- physical, regulatory and market constraints on transmission facilities in certain regions that limit or prevent us from selling power generated by certain of our facilities;
- limited access to capital due to our financial condition since July 2002 and the resulting contraction of our ability to conduct business in the merchant energy markets; and
- changes and turnover in senior and middle management since June 2002 in connection with our restructuring.

We expect that these generally weak market conditions will continue for the foreseeable future in some markets. Historically, we have believed that, as supply surpluses begin to tighten and as market rules and regulatory conditions stabilize, prices will improve for energy, capacity and ancillary services. This view is consistent with our belief that in the long run market prices will support an adequate rate of return on the construction of new power generation assets needed to meet increasing demand. This view is currently being challenged in certain markets as regulatory actions and market rules unfold that limit the ability of merchant power companies to earn favorable returns on existing and new investments. To the extent unfavorable regulatory and market conditions exist in the long term; we could have significant impairments of our property, plant and equipment, which, in turn, could have a material adverse effect on our results of operations. Further, this could lead to us closing certain of our facilities resulting in additional economic losses and liabilities.

Asset Sales. As part of our strategy, we plan to continue the selective divestment of certain assets. Since July 2002, we have sold or made arrangements to sell a number of assets and equity investments. In addition, we are currently marketing our interest in certain other non-strategic assets.

Discontinued Operations. We have classified certain business operations, and gains/ losses recognized on sale, as discontinued operations for projects that were sold or have met the required criteria for such classification pending final disposition. Accounting regulations require that continuing operations are reported separately in the income statement from discontinued operations, and that any gain or loss on the disposition of any such business be reported along with the operating results of such business. Assets classified as "discontinued operations" on our balance sheet as of December 31, 2003 include McClain, Penobscot Energy

Recovery Company (PERC), Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or “Cobee”, LSP Energy, Hsin Yu and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC). For the periods January 1, 2003 through December 5, 2003, discontinued results of operations include our McClain, PERC, Cobee, Killingholme, NEO Landfill Gas, Inc., or “NLGI”, seven NEO Corporation projects (NEO Fort Smith LLC, NEO Woodville LLC, NEO Phoenix LLC, NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC), Timber Energy Resources, Inc., or “TERI”, Cahua, Energia Pacasmayo, LSP Energy and Hsin Yu projects. For the period December 6, 2003 through December 31, 2003, discontinued results of operations included McClain, PERC, Cobee, LSP Energy, Hsin Yu and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC). All prior periods presented have been restated accordingly.

The following table summarizes our discontinued operations for all periods presented in our consolidated financial statements:

Discontinued Operations

Projects	Initial Discontinued Operations Treatment	Disposal Date
Bulo Bulo	Second Quarter 2002	Fourth Quarter 2002
Crockett Cogeneration Project	Third Quarter 2002	Fourth Quarter 2002
Csepel and Entrade	Third Quarter 2002	Fourth Quarter 2002
Killingholme	Fourth Quarter 2002	First Quarter 2003
NLGI	Second Quarter 2003	Second Quarter 2003
NEO Corp. projects (NEO Fort Smith LLC, NEO Woodville LLC, NEO Phoenix LLC)	Fourth Quarter 2003	Fourth Quarter 2003
TERI	Third Quarter 2003	Third Quarter 2003
Cahua and Pacasmayo	Fourth Quarter 2003	Fourth Quarter 2003
McClain	Third Quarter 2003	Third Quarter 2004
PERC	First Quarter 2004	Second Quarter 2004
Cobee	First Quarter 2004	Second Quarter 2004
LSP Energy	Second Quarter 2004	Third Quarter 2004
Hsin Yu	Second Quarter 2004	Second Quarter 2004
NEO Corp. projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC)	Third Quarter 2004	Third Quarter 2004

New Management. On October 21, 2003, we announced the appointment of David Crane as our President and Chief Executive Officer, effective December 1, 2003. Before joining us, Mr. Crane served as the Chief Executive Officer of London-based International Power PLC and has over 12 years of energy industry experience. On March 11, 2004 we announced the appointment of Robert Flexon as Executive Vice President and Chief Financial Officer, effective March 29, 2004. Before joining us Mr. Flexon served as Vice President, Work Processes, Corporate Resources and Development at Hercules, Inc. In addition, we have filled several other senior and middle management positions over the last 12 months. Our board of directors currently is comprised of Mr. Crane and ten independent individuals, three of whom have been designated by MatlinPatterson, a significant holder of NRG common stock.

Independent Registered Public Accounting Firm; Audit Committee. On May 3, 2004, we announced that we had initiated a search for a new independent auditor because PricewaterhouseCoopers LLP, our previous auditor, informed us that they would not be standing for re-election as our independent auditor for the year ended December 31, 2004. For each of the two fiscal years ended December 31, 2002 and 2003 and for the period from January 1, 2004 through April 27, 2004, there had been no disagreements with PricewaterhouseCoopers on any matters of accounting principles or practices, financial statement disclosure or auditing scope or procedure.

On May 25, 2004, we announced that the audit committee of our board of directors had engaged KPMG LLP to serve as our independent auditor, effective immediately. On August 4, 2004, our stockholders ratified the appointment of KPMG LLP as our independent registered public accounting firm at our 2004 annual meeting of stockholders. KPMG's engagement with us commenced with its review of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2004.

Our new board of directors appointed an audit committee consisting entirely of independent directors in January 2004. Pursuant to its charter, the committee appoints, retains, oversees, evaluates, compensates and terminates on its sole authority our independent auditors and approves all audit engagements, including the scope, fees, and terms of each engagement. The audit committee's oversight process is intended to ensure that we will continue to have high-quality, cost efficient independent auditing services.

Results of Operations

Due to the adoption of Fresh Start as of December 5, 2003, Reorganized NRG's balance sheet, statement of operations and statement of cash flows have not been prepared on a consistent basis with, and are therefore generally not comparable to those of the Predecessor Company prior to the application of Fresh Start. In accordance with SOP 90-7, Reorganized NRG's balance sheet, statement of operations and statement of cash flows have been presented separately from those of the Predecessor Company.

Reorganized NRG's revenues from majority-owned operations, operating costs and expenses and general, administrative and development expenses, were not significantly affected by the adoption of Fresh Start. Therefore, the Predecessor Company's 2003 amounts have been combined with Reorganized NRG's 2003 amounts for comparison and analysis purposes herein.

	Predecessor Company			Reorganized NRG	
	Year Ended December 31,		For the Period January 1 - December 5,	For the Period December 6 - December 31,	
	2001	2002	2003	2003	Total 2003
			(In thousands)		
Revenues from majority-owned operations	$2,085,350	$1,938,293	$1,798,387	**$ 138,490**	**$1,936,877**
Cost of majority-owned operations	1,375,390	1,332,446	1,355,909	**95,541**	**1,451,450**
General, administrative and development	187,165	218,852	170,330	**12,518**	**182,848**

Reorganized NRG's net loss, equity in earnings of unconsolidated affiliates, depreciation and amortization, other income (expense), other charges, income taxes and discontinued operations were affected by the adoption of Fresh Start. Therefore, the Predecessor Company's 2003 and the Reorganized NRG's 2003 amounts are discussed separately for comparison and analysis purposes herein.

	Predecessor Company			Reorganized NRG
	Year Ended December 31		For the Period January 1 - December 5,	For the Period December 6 - December 31,
	2001	2002	2003	2003
			(In thousands)	
Net income/(loss)	$ 265,204	$(3,464,282)	$ 2,766,445	$ 11,025
Depreciation and amortization	140,976	207,027	218,843	11,808
Other expense	(131,096)	(572,227)	(286,903)	(5,418)
Other charges/(credits)	—	2,563,060	(3,220,605)	2,461
Income tax expense/(benefit)	40,221	(166,867)	37,929	(661)
Income/(loss) from discontinued operations	54,702	(675,830)	(182,633)	(380)

For the Year Ended December 31, 2003 Compared to the Year Ended December 31, 2002

Net Income

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded net income of $2.8 billion. Net income for the period is directly attributable to our emerging from bankruptcy and adopting the Fresh Start provisions of SOP 90-7. Upon the confirmation of our Plan of Reorganization and our emergence from bankruptcy we were able to remove significant amounts of long-term debt and other prepetition obligations from our balance sheet. Accordingly, as part of net income, we recorded a net gain of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations) as the impact of our adopting Fresh Start in our statement of operations, $6.0 billion of this amount is directly related to the forgiveness of debt and settlement of substantial amounts of our pre-petition obligations upon our emergence from bankruptcy. In addition to the removal of substantial amounts of pre-petition debt and other obligations from our balance sheet, we have also revalued our assets and liabilities to fair value, accordingly we have substantially written down the value of our fixed assets. We have recorded a net $1.7 billion charge related to the revaluation of our assets and liabilities within the Fresh Start Reporting adjustment line of our consolidated statement of operations. In addition to our recording adjustments related to our emergence from bankruptcy, we also recorded substantial charges related to other items such as the settlement of certain outstanding litigation in the amount of $462.6 million, write downs and losses on the sale of equity investments of $147.1 million, advisor cost and legal fees directly attributable to our being in bankruptcy of $197.8 million and $237.6 million of other asset impairment and restructuring costs incurred prior to our filing for bankruptcy. Net income for the period January 1, 2003 through December 5, 2003 was also favorably impacted by our not recording interest expense on substantial amounts of corporate level debt while we were in bankruptcy and by the continued favorable results experienced by our equity investments.

During the year ended December 31, 2002, we recognized a net loss of $3.5 billion. The loss from continuing operations incurred during 2002 primarily consisted of $2.6 billion of other charges consisting primarily of asset impairments.

Reorganized NRG

During the period December 6, 2003 through December 31, 2003, we recognized net income of $11.0 million or $0.11 per share of common stock. Net income was directly attributable to a number of factors some of which are discussed below. From an overall operational perspective our facilities were profitable during this period. Our results were adversely impacted by our having to continue to satisfy the standard offer service contract that we entered into with Connecticut Light & Power, or “CL&P” in 2000. As a result of our inability to terminate this contract during our bankruptcy proceeding we continued to be exposed to losses under this contract. These losses were incurred, as we were unable to satisfy the requirements of this contract at a price/cost below the contracted sales price. Upon our adoption of Fresh Start, we recorded at fair value, all assets and liabilities on our opening balance sheet and accordingly we recorded as an obligation the fair value of the CL&P contract. During the period December 6, 2003 through December 31, 2003, we recognized as revenues, the entire fair value of this contract effectively offsetting the actual losses incurred under this contract. The CL&P contract terminated on December 31, 2003.

Revenues from Majority Owned Operations

Our operating revenues from majority owned operations were $1.9 billion in 2003, compared to $1.9 billion in the prior year, a decrease of $1.4 million or less than 0.1%.

Revenues from majority owned operations of $1.9 billion for the year 2003, includes $1.1 billion of energy revenues, $605.9 million of capacity revenues, $128.0 million of alternative energy, $14.1 million of O&M fees and $118.3 million of other revenues which include financial and physical gas sales, sales from our Schkopau facility and NEPOOL expense reimbursements. The decrease of $1.4 million is due to increased capacity revenues resulting from additional projects becoming operational in the later part of 2002, higher sales in New

York, and by our recognizing, as additional revenues, the fair value of the out-of-market CL&P contract upon our emergence from bankruptcy. Offsetting these increases, we continued to recognize losses on the CL&P contract throughout 2003 resulting from higher market prices and lower generation.

Cost of Majority-Owned Operations

Our cost of majority owned operations related to continuing operations was $1.5 billion in 2003, compared to $1.3 billion for 2002, an increase of $119.0 million or 8.9%. For 2003 and 2002, cost of majority owned operations represented 74.9% and 68.7% of revenues from majority owned operations, respectively. Cost of majority owned operations, consists primarily of cost of energy (primarily fuel costs), labor, operating and maintenance costs and non income based taxes related to our majority owned operations.

For the year 2003, cost of energy was $902.4 million compared to $900.9 million for 2002, representing an increase of $1.5 million. As a percent of revenue from majority owned operations, cost of energy was 46.6% and 46.5%, for 2003 and 2002, respectively. Cost of energy was directly affected by an overall decrease in the cost of fuel during 2003 and a favorable change in the fair value of our energy related derivatives resulting from contract terminations. Offsetting this decrease are liquidated damages of $72.9 million triggered from our financial condition.

Depreciation and Amortization

Predecessor Company

Our depreciation and amortization expense related to continuing operations was $218.8 million for the period January 1, 2003 through December 5, 2003 and $207.0 million for the year ended December 31, 2002. Depreciation and amortization consists of the allocation of our historical depreciable fixed asset costs over the remaining lives of such property as well as the amortization of certain contract based intangible assets.

Reorganized NRG

Our depreciation and amortization expense related to continuing operations was $11.8 million for the period December 6, 2003 through December 31, 2003. Depreciation and amortization consists of the allocation of our newly valued basis in our fixed assets over newly determined remaining fixed asset lives. As part of adopting the Fresh Start concepts of SOP 90-7 our tangible fixed assets were recorded at fair value as determined by a third party valuation expert who we also consulted with in determining the appropriate remaining lives for our tangible depreciable property. Depreciation expense for this period was based on preliminary depreciable lives and asset balances.

General, Administrative and Development

Our general, administrative and development costs for 2003 were $182.9 million compared to $218.9 million for 2002, a decrease of $36.0 million or 16.4%. For 2003 and 2002, general, administrative and development costs represent 9.4% and 11.3% of revenues from majority owned operations, respectively. This decrease is due to decreased costs related to work force reduction efforts, cost reductions due to the closure of certain international offices and reduced legal costs. Outside services also decreased, due to less non-restructuring legal activities.

Other Charges (Credits)

During the period January 1, 2003 to December 5, 2003, we recorded other credits of $3.2 billion, which consisted primarily of $228.9 million related to asset impairments, $462.6 million related to legal settlements and $197.8 million related to reorganization charges and $8.7 million related to restructuring charges. We also incurred a $4.1 billion credit related to Fresh Start adjustments. During 2002, we recorded other charges of $2.6 billion, which consisted primarily of $2.5 billion related to asset impairments and $111.3 million related to restructuring charges.

We review the recoverability of our long-lived assets on a periodic basis and if we determined that an asset was impaired, we compared asset-carrying values to total future estimated undiscounted cash flows. Separate analyses are completed for assets or groups of assets at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The estimates of future cash flows included only future cash flows, net of associated cash outflows, directly associated with and expected to arise as a result of our assumed use and eventual disposition of the asset. Cash flow estimates associated with assets in service are based on the asset's existing service potential. The cash flow estimates may include probability weightings to consider possible alternative courses of action and outcomes, given the uncertainty of available information and prospective market conditions.

If an asset was determined to be impaired based on the cash flow testing performed, an impairment loss was recorded to write down the asset to its fair value. Estimates of fair value were based on prices for similar assets and present value techniques. Fair values determined by similar asset prices reflect our current estimate of recoverability from expected marketing of project assets. For fair values determined by projected cash flows, the fair value represents a discounted cash flow amount over the remaining life of each project that reflects project-specific assumptions for long-term power pool prices, escalated future project operating costs, and expected plant operation given assumed market conditions.

Impairment charges (credits) included the following for the year ended December 31, 2002 and for the period January 1, 2003 to December 5, 2003 and the period December 6, 2003 through December 31, 2003.

		Predecessor Company		Reorganized NRG	
Project Name	Project Status	Year Ended December 31, 2002	For the Period January 1 – December 5, 2003	For the Period December 6 – December 31, 2003	Fair Value Basis
Devon Power LLC	Operating at a loss	$ —	$ 64,198	$ —	Projected cash flows
Middletown Power LLC	Operating at a loss	—	157,323	—	Projected cash flows
Arthur Kill Power, LLC	Terminated construction project	—	9,049	—	Projected cash flows
Langage (UK)	Terminated	42,333	(3,091)	—	Estimated market price/Realized gain
Turbine	Sold	—	(21,910)	—	Realized gain
Berrians Project	Terminated	—	14,310	—	Realized loss
Termo Rio	Terminated	—	6,400	—	Realized loss
Nelson	Terminated	467,523	—	—	Similar asset prices
Pike	Terminated	402,355	—	—	Similar asset prices
Bourbonnais	Terminated	264,640	—	—	Similar asset prices
Meriden	Terminated	144,431	—	—	Similar asset prices
Brazos Valley	Foreclosure completed in January 2003	102,900	—	—	Projected cash flows
Kendall and other expansion Projects	Terminated	55,300	—	—	Projected cash flows
Turbines & other costs	Equipment being marketed	701,573	—	—	Similar asset prices
Audrain	Operating at a loss	66,022	—	—	Projected cash flows
Somerset	Operating at a loss	49,289	—	—	Projected cash flows
Bayou Cove	Operating at a loss	126,528	—	—	Projected cash flows
Other		28,851	2,617	—	
Total impairment charges (credits)		$2,451,745	$ 228,896	$ —	

Reorganization Items

For the period from January 1, 2003 to December 5, 2003, we incurred $197.8 million in reorganization costs and for the period from December 6, 2003 to December 31, 2003 we incurred $2.5 million in reorganization costs. All reorganization costs have been incurred since we filed for bankruptcy in May 2003. The following table provides the detail of the types of costs incurred (in thousands):

	Predecessor Company	Reorganized NRG
	For the Period January 1 – December 5, 2003	For the Period December 6 – December 31, 2003
Reorganization items		
Professional fees	$ 82,186	**$ 2,461**
Deferred financing costs	55,374	—
Pre-payment settlement	19,609	—
Interest earned on accumulated cash	(1,059)	—
Contingent equity obligation	41,715	—
Total reorganization items	$ 197,825	**$ 2,461**

Restructuring Charges

We incurred total restructuring charges of approximately $111.3 million for the year ended December 31, 2002. These costs consisted of employee separation costs and advisor fees. We incurred an additional $8.7 million of employee separation costs and advisor fees during 2003 until we filed for bankruptcy in May 2003. Subsequent to that date we recorded all advisor fees as reorganization costs.

Legal Settlement Costs

During 2003, we recorded $396.0 million in connection with the resolution of the FirstEnergy Arbitration Claim. As a result of this resolution, FirstEnergy retained ownership of the Lake Plant Assets and received an allowed general unsecured claim of $396.0 million under the NRG plan of reorganization submitted to the bankruptcy court.

In November 2003, we settled various litigation with Fortistar Capital in which Fortistar Capital released us from all litigation claims in exchange for a $60.0 million pre-petition claim and an $8.0 million post-petition claim. We had previously recorded $10.8 million in connection with various legal disputes with Fortistar Capital; accordingly, we recorded an additional $57.2 million during November 2003.

In August of 1995, we entered into a Marketing, Development and Joint Proposing Agreement or “the Marketing Agreement”, with Cambrian Energy Development LLC, or “Cambrian.” Various claims had arisen in connection with this Marketing Agreement. In November 2003, we entered into a Settlement Agreement with Cambrian where we agreed to transfer our 100% interest in three gasco projects (NEO Ft. Smith, NEO Phoenix and NEO Woodville) and our 50% interest in two genco projects (MM Phoenix and MM Woodville) to Cambrian. In addition, we agreed to pay approximately $1.8 million in settlement of royalties incurred in connection with the Marketing Agreement. We had previously recorded a liability for royalties owed to Cambrian; therefore, we recorded an additional $1.4 million during November 2003.

In November 2003, we settled our dispute with Dick Corporation in connection with Meriden Gas Turbines, which resulted in our recording an additional liability of $8.0 million in November 2003.

Fresh Start Adjustments

During the fourth quarter of 2003, we recorded a net credit of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations) in connection with fresh start adjustments as discussed in Item 15 — Note 3. Following is a summary of the significant effects of the reorganization and Fresh Start:

	(In millions)
Discharge of corporate level debt	$ 5,162
Discharge of other liabilities	811
Establishment of creditor pool	(1,040)
Receivable from Xcel	640
Revaluation of fixed assets	(1,392)
Revaluation of equity investments	(207)
Valuation of SO(2) emission credits	374
Valuation of out of market contracts, net	(400)
Fair market valuation of debt	108
Valuation of pension liabilities	(61)
Other valuation adjustments	(100)
Total Fresh Start adjustments	3,895
Less discontinued operations	224
Total Fresh Start adjustments — continuing operations	$ 4,119

Other Income (Expense)

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded other expense of $286.9 million. Other expense consisted primarily of $329.9 million of interest expense and $147.1 million of write downs and losses on sales of equity method investments, partially offset by equity in earnings of unconsolidated affiliates of $170.9 million and $19.2 million of other income.

For the year ended December 31, 2002, other expenses was $572.2 million, which consisted primarily of $452.2 million of interest expense and $200.5 million of write downs and losses on sales of equity method investments.

Interest expense for the period January 1, 2003 through December 5, 2003 of $329.9 million consisted of interest expense on both our project and corporate level interest bearing debt. In addition, interest expense includes the amortization of debt issuance costs and any interest rate swap termination costs. Subsequent to our entering into bankruptcy we ceased the recording of interest expense on our corporate level debt as these prepetition claims were deemed to be impaired and subject to compromise. We did not however cease to record interest expense on the project level debt outstanding at our Northeast Generating and South Central Generating facilities even though these entities were also in bankruptcy as these claims were deemed to be most likely not impaired and not subject to compromise. We also recorded substantial amounts of fees and costs related to our acquiring a debtor in possession financing arrangement while we were in bankruptcy. In addition, upon our emergence from bankruptcy we wrote off any remaining deferred finance costs related to our corporate and project level debt including our Northeast and South Central project level debt as it was probable that they would be refinanced upon our emergence from bankruptcy.

Reorganized NRG

Other income (expense) for the period December 6, 2003 through December 31, 2003, was an expense of $5.4 million and consisted primarily of $18.9 million of interest expense, partially offset by $13.5 million of equity earnings from unconsolidated subsidiaries.

Interest expense for the period December 6, 2003 through December 31, 2003 of $18.9 million consists primarily of interest expense at the corporate level, primarily related to the newly issued high yield notes, term loan facility and revolving line of credit used to refinance certain project level financings. In addition, interest expense includes the amortization of deferred financing costs incurred as a result of our refinancing efforts and the amortization of discounts and premiums recorded upon the marking of our debt to fair value upon our adoption of the Fresh Start provision of SOP 90-7.

Minority Interest in Earnings of Consolidated Subsidiaries

For the period December 6, 2003 through December 31, 2003, minority interest in earnings of consolidated subsidiaries was $134,000 and relates primarily to Northbrook New York and Northbrook Energy.

Write-Downs and Losses on Sales of Equity Method Investments

As we periodically review our equity method investments for impairments we have taken substantial write-downs and losses on sales of equity method investments during the period January 1, 2003 through December 5, 2003 and for the year 2002. In 2003 we recorded impairments and losses on the sales of investments of $147.1 million compared to $200.5 million in 2002. The $147.1 million recorded in 2003 consists of the write down of our investment in the Loy Yang project of $146.4 million and our investment in the NEO Corporation — Minnesota Methane project of $12.3 million during 2003. These losses were partially offset by gains on the sale of our investment in the ECKG and Mustang projects. During 2002 we recorded write-downs and losses on sales of equity method investments of $200.5 million. The $200.5 million recorded in 2002 consists of a write down of our investment in the Loy Yang project of $111.4 million, a loss of $48.4 million on the transfer of our interest in the Sabine River Works project to our partner, a $14.2 million write down related to our investment in our EDL project, a write down of our investment in our Kondapalli project of $12.7 million and a write down of our investment in NEO Corporation — Minnesota Methane and MM Biogas of $12.3 million and $3.3 million, respectively among others. See Item 15 — Note 7 to the Consolidated Financial Statements for additional information.

Equity Earnings from Unconsolidated Affiliates

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded $170.9 million of equity earnings from investments in unconsolidated affiliates. Our 50% investment in West Coast Power comprised $98.7 million of this amount with our investments in the Mibrag, Loy Yang, Gladstone and Rocky Road projects comprising $21.8 million, $17.9 million, $12.4 million and $6.9 million, respectively, with the remaining amounts attributable to various domestic and international equity investments. Our investment in West Coast Power continues to generate favorable earnings as well as our investments in Mibrag, Loy Yang, Gladstone and Rocky Road. For the year ended December 31, 2002, equity earnings from investments in unconsolidated affiliates was $69.0 million.

Reorganized NRG

Equity in earnings of unconsolidated affiliates of $13.5 million consists primarily of equity earnings from our 50% ownership in West Coast Power of $9.3 million.

Discontinued Operations

During the first quarter of 2004, we determined that two additional projects had met the necessary criteria for discontinued operations treatment, Penobscot Energy Recovery Company, or “PERC “and Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or “Cobee” accordingly, all periods presented have been restated to reflect the addition of these projects as discontinued operations.

During the second quarter of 2004, we determined that two more projects had met the necessary criteria for discontinued operations treatment, LSP Energy and Hsin Yu. Accordingly, all periods presented have been restated to reflect the addition of these projects as discontinued operations.

During the third quarter of 2004, we determined that four NEO Corporation projects had met the necessary criteria for discontinued operations treatment. Accordingly, all periods presented have been restated to reflect the addition of these projects as discontinued operations.

Predecessor Company

As of December 5, 2003, we classified as discontinued operations the operations and gains/losses recognized on the sales of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. For the period January 1, 2003 through December 5, 2003, discontinued operations consist of the historical operations and net gains/losses related to our Killingholme, McClain, PERC, Cobee, NLGI, NEO Corporation projects, TERI, Cahua, Energia Pacasmayo, LSP Energy and Hsin Yu projects. Discontinued operations for the year ended December 31, 2002 consisted of our Crockett Cogeneration, Entrade, Killingholme, Csepel, Bulo Bulo, McClain, PERC, Cobee, NLGI, NEO Corporation projects, TERI, Cahua, Energia Pacasmayo, LSP Energy and Hsin Yu projects.

For the period January 1, 2003 through December 5, 2003, the results of operations related to such discontinued operations was a net loss of $182.6 million due to a loss on the sale of our Peru projects, impairment charges recorded at McClain and NLGI and fresh start adjustments at LSP Energy.

During 2002 we recognized a loss on discontinued operations of $675.8 million due to asset impairments recorded at Killingholme, NLGI, TERI, LSP Energy and Hsin Yu projects.

Reorganized NRG

Discontinued operations for the period December 6, 2003 through December 31, 2003 is comprised of a loss of $0.4 million attributable to the on going operations of our McClain, PERC, Cobee, LSP Energy, Hsin Yu and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC).

Income Tax

Predecessor Company

Income tax benefit/expense for the period January 1, 2003 through December 5, 2003 was a tax expense of $37.9 million as compared to a tax benefit of $166.9 million for the year ended December 31, 2002. The income tax expense for the period ended December 5, 2003 was primarily due to separate company income tax liabilities and an increase in the valuation allowance against deferred tax assets. An additional valuation allowance of $33 million was recorded against deferred tax assets of NRG West Coast as a result of its conversion from a corporation to a single member limited liability company (a disregarded entity for federal income tax purposes).

The effective income tax rate for the period January 1, 2003 through December 5, 2003 is relatively low since the U.S. net operating loss carryforwards are offset by the cancellation of debt income resulting from the Bankruptcy. The income tax benefit for the year ended December 31, 2002 was primarily due to the increase in deferred tax assets relating to impairments recognized for financial reporting purposes. A valuation allowance was increased limiting the recognition of deferred tax assets to the extent of previously recorded deferred tax liabilities.

Income taxes have been recorded on the basis that our U.S. subsidiaries and we will file separate federal income tax returns for the period January 1, 2003 through December 5, 2003. Since our U.S. subsidiaries and we will not be included in the Xcel Energy consolidated tax group, each of our U.S. subsidiaries that is classified, as a corporation for U.S. income tax purposes must file a separate federal income tax return. It is uncertain if, on a stand-alone basis, we would be able to fully realize deferred tax assets related to net operating losses and other temporary differences, therefore a full valuation allowance has been established.

Reorganized NRG

Income tax benefit/expense for the period December 6, 2003 through December 31, 2003 was a tax benefit of $0.7 million which consists of a U.S. tax benefit of $1.5 million and foreign tax expense of $0.8 million. The foreign tax expense for the period is due to earnings in the foreign jurisdictions.

Our U.S. subsidiaries and we will file a consolidated federal income tax return for the period December 6, 2003 through December 31, 2003. With the exception of alternative minimum tax, or “AMT”, we anticipate that our cash tax rate for the next 5 years will be relatively low as we realize the cash tax benefits from using our net operating loss carryforwards. For AMT purposes, utilization of net operating losses is limited on an annual basis.

Due to the uncertainty of realization of deferred tax assets related to net operating losses and other temporary differences, the change in U.S. current and deferred income taxes has been fully offset by a change in the valuation allowance and our U.S. net deferred tax assets at December 31, 2003 were offset by a full valuation allowance in accordance with SFAS 109. Regarding the valuation allowance as of December 5, 2003, SOP 90-7 requires any future benefits from reducing the valuation allowance from preconfirmation net operating loss carryforwards be reported as a direct addition to paid-in-capital versus a benefit on our income statement. Consequently, our effective tax rate in post Bankruptcy emergence years will not benefit from utilization of our net operating loss carryforwards which were fully valued as of the date of our emergence from Bankruptcy.

As of December 31, 2003, our management intends to indefinitely reinvest the earnings from our foreign operations. Accordingly, U.S. income taxes and foreign withholding taxes were not provided on the earnings of our foreign subsidiaries.

For the Year Ended December 31, 2002 Compared to the Year Ended December 31, 2001

Net Income/(Loss)

During the year ended December 31, 2002, we recognized a net loss of $3.5 billion. This loss represented a decrease in earnings of $3.7 billion compared to net income of $265.2 million for the same period in 2001. Our loss from continuing operations was $2.8 billion for the year ended December 31, 2002 compared to net income of $210.5 million from continuing operations for the same period in 2001. The loss from continuing operations incurred during 2002 primarily consists of $2.6 billion of other charges consisting primarily of asset impairments.

During 2002, our continuing operations experienced less favorable results than those experienced during the same period in 2001. Overall, our domestic power generation operations performed poorly compared to the same period in 2001. Our domestic operations experienced reductions in domestic energy and capacity sales and an overall decrease in power pool prices and related spark spreads (the monetary difference between the price of power and fuel cost). During the fourth quarter of 2002, an additional reserve for uncollectible receivables in California was established by West Coast Power, the California joint venture of which we own 50%, which reduced our equity in the earnings of that joint venture by approximately $58.5 million on a pre-tax basis. In addition, West Coast Power’s results were already less than those recorded in 2001 due to less favorable contracts and reductions in sales of energy and capacity. In addition, increased administrative costs, depreciation and interest expense from completed construction costs also contributed to the less than favorable results in 2002. Partially offsetting these earnings reductions was the recognition, in the fourth quarter of 2002, of approximately $51.0 million of additional revenues related to the contractual termination of a power purchase agreement with our Indian River project.

During the third quarter of 2002, we experienced credit rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity. These events led to impairments of a number of our assets, resulting in pre-tax charges related to continuing operations of approximately $2.5 billion during 2002. In addition, approximately $200.5 million of net losses on sales and write-downs of equity method investments were recorded in 2002.

Operating results of majority-owned projects that were sold or have met the criteria to be considered as held-for-sale have been classified as discontinued operations. The period ended December 31, 2002, consisted of the historical operations and net gains/losses related to our Crockett Cogeneration, Entrade, Killingholme, Csepel, Bulo Bulo, McClain, PERC, Cobee, NLGI, NEO Fort Smith LLC, NEO Woodville LLC, NEO Phoenix LLC, NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC, NEO Tajiguas LLC, TERI, Cahua, Energia Pacasmayo, LSP Energy and Hsin Yu Projects.

During 2002, we expensed approximately $111.3 million for costs related to our financial restructuring. These costs include expenses for financial and legal advisors, contract termination costs, employee separation and other restructuring activities.

Revenues from Majority-Owned Operations

Our operating revenues from majority-owned operations were $1.9 billion in 2002 compared to $2.1 billion in the prior year, a decrease of $147.1 million or approximately 7.1%. Revenues from majority-owned operations for the year ended December 31, 2002, consisted primarily of power generation revenues from domestic operations of approximately $1.5 billion in 2002 compared with $1.6 billion in 2001, a decrease of $158.1 million. This decrease in domestic generation revenue is due to reductions in energy and capacity sales and an overall decrease in power pool prices.

The Northeast region experienced decreased revenues, as they were significantly affected by a combination of lower capacity revenues and a decline in megawatt hour generation compared with 2001. This decline in generation is attributable to an unseasonably warm winter and cooler spring and a slowing economy, which reduced demand for electricity, together with new regulation, which reduced price volatility, particularly in New York City.

Our International revenues from majority-owned operations decreased by $6.9 million or 2.4% from 2001 to 2002. The Australia region reported a reduction in revenues of $42.5 million while increases were reported from the Other International region of $35.6 million. The reduction in Australia revenue is primarily due to a decline in energy prices and the loss of a significant contract at Flinders. The increase in Other International revenue is primarily due to a full year of operations for acquisitions made in 2001.

Operating Costs and Expenses

For the year ended December 31, 2002, cost of majority-owned operations related to continuing operations was $1.3 billion compared to $1.4 billion for 2001, a decrease of $42.9 million or approximately 3.1%. For the years ended December 31, 2002 and 2001, cost of majority-owned operations represented approximately 68.7% and 66.0% of revenues from majority-owned operations, respectively. Cost of majority-owned operations consists primarily of cost of energy (primarily fuel costs), labor, operating and maintenance costs and non-income based taxes related to our majority-owned operations.

For the year ended December 31, 2002, cost of energy was $900.9 million compared to $971.4 million for the year ended December 31, 2001. This represents a decrease of $70.5 million or 7.3%. As a percent of revenue from majority-owned operations cost of energy was 46.5% and 46.6% for the years ended December 31, 2002 and 2001, respectively.

For the year ended December 31, 2002, operating and maintenance costs were $359.8 million compared to $319.5 million for the year ended December 31, 2001. This represents an increase of $40.3 million or 12.6%. As a percent of revenue from majority-owned operations, operating and maintenance costs represented 18.6% and 15.3%, for the years ended December 31, 2002 and 2001, respectively. The increase in operating and maintenance expense is primarily due to a full year of expense in 2002 related to assets acquired during 2001.

Depreciation and Amortization

For the year ended December 31, 2002, depreciation and amortization related to continuing operations was $207.0 million, compared to $141.0 million for the year ended December 31, 2001, an increase of

$66.0 million or approximately 46.8%. This increase is primarily due to the addition of property, plant and equipment related to our acquisitions of electric generating facilities completed during 2002.

General, Administrative and Development

For the year ended December 31, 2002, general, administrative and development costs were $218.9 million, compared to $187.2 million for the year ended December 31, 2001, an increase of $31.7 million or approximately 16.9%. For the year ended December 31, 2002 and 2001, general, administrative and development costs represent 11.3% and 9.0% of revenues from majority-owned operations, respectively. This increase is primarily due to an increase in bad debt expense. Additionally there was an increase in other general administrative expenses due to 2001 acquisitions and newly constructed facilities coming on line. These increases were partially offset by decreases in business development expenses and other reductions to costs previously incurred to support international and expanded operations.

Other Charges

During the third quarter of 2002, we experienced credit rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity. We applied the provisions of SFAS No. 144 to our construction and operational projects. We completed an analysis of the recoverability of the asset carrying values of our projects factoring in the probability of different courses of action available to us given our financial position and liquidity constraints. As a result, we determined during the third quarter that many of our construction projects and certain operational projects were impaired and should be written down to fair market value. To estimate fair value, our management considered discounted cash flow analyses, bids and offers related to those projects and prices of similar assets. During 2002, we recorded asset impairment and other special charges related to continuing operations of $2.6 billion. See Item 15 — Note 8 to the Consolidated Financial Statements for additional information.

Other Income (Expense)

For the year ended December 31, 2002, total other expense was $572.2 million, compared to $131.1 million for the year ended December 31, 2001, an increase of $441.1 million or approximately 336.5%. The increase in total other expense from 2001 consisted primarily of an increase in interest expense and $200.5 million of write downs and losses on sales of equity method investments combined with lower equity earnings of unconsolidated affiliates.

For the year ended December 31, 2002, we had equity in earnings of unconsolidated affiliates of $69.0 million, compared to $210.0 million for 2001, a decrease of $141.0 million or approximately 67.1%. The $141.0 million decrease in equity earnings from unconsolidated affiliates is due primarily to unfavorable results at West Coast Power in 2002 as compared to the same period in 2001. During 2002, West Coast Power had long-term contracts that were less favorable than those held in 2001. In addition during 2002, West Coast Power established reserves for certain receivables not considered recoverable from California PX. Our share of this reserve was approximately $58.5 million on a pre-tax basis.

For the year ended December 31, 2002, interest expense (which includes both corporate and project level interest expense) was $452.2 million, compared to $364.1 million in 2001, an increase of $88.1 million or approximately 24.2%. This increase is due primarily to increased corporate and project level debt. We issued substantial amounts of long-term debt at both the corporate level (recourse debt) and project level (non-recourse debt) to either directly finance the acquisition of electric generating facilities or refinance short-term bridge loans incurred to finance such acquisitions.

Other income was a gain of $11.4 million, as compared to $23.0 million for the year ended December 31, 2001, a decrease of $11.6 million, or approximately 50.3%. Other income consists primarily of interest income on cash balances and realized and unrealized foreign currency exchange gains and losses. Interest income was lower during 2002 due to lower interest from affiliates, primarily related to West Coast Power. In addition, there were significant foreign currency exchange losses during 2002.

Write-Downs and Losses on Sales of Equity Method Investments

For the year ended December 31, 2002, write-downs and losses on equity method investments were $200.5 million. The $200.5 million charge consists primarily of write-downs related to our investment in Loy Yang in the total amount of $111.4 million. In addition, we recorded a loss of $48.4 million upon the transfer of our investment in SRW Cogeneration and recorded write-downs of $14.2 million and $3.6 million of our investments in EDL and Collinsville, respectively.

Income Tax

Income tax benefit/expense for the year ended December 31, 2002 was a tax benefit of $166.9 million as compared to a tax expense of $40.2 million for the year ended December 31, 2001. The income tax benefit for the year ended December 31, 2002 was primarily due to the increase in deferred tax assets relating to impairments recognized for financial reporting purposes. A valuation allowance was increased limiting the recognition of deferred tax assets to the extent of previously recorded deferred tax liabilities. The income tax expense for the year ended December 31, 2001 was primarily due to U.S. and foreign operating earnings reduced by tax credits of $35.0 million.

For 2002, income taxes were recorded on the basis that Xcel Energy would not include us in its consolidated federal income tax return following Xcel Energy's acquisition of our public shares on June 3, 2002. Since Xcel Energy did not include us in its consolidated federal income tax return, we and each of our U.S. subsidiaries that is classified as a corporation for U.S. income tax purposes must file separate federal income tax returns. It is uncertain if, on a stand-alone basis, we will be able to fully realize deferred tax assets related to net operating losses and other temporary differences, consequently, a valuation allowance of $1.2 billion was recorded as of December 31, 2002.

For 2001, our U.S. subsidiaries and we were included in the Xcel Energy consolidated federal income tax return through March 12, 2001, the date of our secondary public offering. For the remainder of the year, we filed a consolidated federal return with our U.S. subsidiaries. Income tax expense was recorded on current and deferred tax liabilities, partially offset by benefits from tax credits.

Discontinued Operations

Subsequent to December 31, 2002, we determined that additional projects had met the necessary criteria for discontinued operations treatment, McClain, PERC, Cobee, NLGI, NEO Fort Smith LLC, NEO Woodville LLC, NEO Phoenix LLC, NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC, NEO Tajiguas LLC, TERI, Cahua, Energia Pacasmayo, LSP Energy and Hsin Yu. Accordingly, we have restated all periods presented to reflect the addition of these projects as discontinued operations.

As of December 31, 2002, we classified the operations and gains/losses recognized on the sales of certain entities as discontinued operations. Discontinued operations consist of the historical operations and net gains/losses related to our Crockett Cogeneration, Entrade, Killingholme, Csepel, Bulo Bulo, McClain, PERC, Cobee, NLGI, NEO Fort Smith LLC, NEO Woodville LLC, NEO Phoenix LLC, NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC, NEO Tajiguas LLC, TERI, Cahua, Energia Pacasmayo, LSP Energy and Hsin Yu that were sold in 2002 or were deemed to have met the required criteria for such classification pending final disposition. For 2002, the results of operations related to such discontinued operations was a net loss of $675.8 million as compared to a gain of $54.7 million for the same period in 2001. The primary reason for the loss recognized in 2002 is due to asset impairments recorded at Killingholme, TERI, NLGI, LSP Energy and Hsin Yu.

Reorganization and Emergence from Bankruptcy

On May 14, 2003, we and 25 of our U.S. affiliates, filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code, "the Bankruptcy Code" in the United States Bankruptcy Court for the Southern District of New York, or the "bankruptcy court."

On May 15, 2003, NRG Energy, PMI, NRG Finance Company I LLC, NRGenerating Holdings (No. 23) B.V. and NRG Capital LLC, collectively “the Plan Debtors”, filed the NRG plan of reorganization and the related Disclosure Statement for Reorganizing Debtors’ Joint Plan of Reorganization Pursuant to Chapter 11 of the United States Bankruptcy Code, as subsequently amended, “the Disclosure Statement.” The Bankruptcy Court held a hearing on the Disclosure Statement on June 30, 2003, and instructed the Plan Debtors to include certain additional disclosures. The Plan Debtors amended the Disclosure Statement and obtained Bankruptcy Court approval for the Third Amended Disclosure Statement for Debtors’ Second Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code.

On November 24, 2003, the bankruptcy court issued an order confirming the NRG plan of reorganization, and the plan became effective on December 5, 2003. On September 17, 2003, the Northeast/ South Central plan of reorganization was proposed after we secured the necessary financing commitments. 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.

Financial Reporting by Entities in Reorganization under the Bankruptcy Code and Fresh Start

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 Statement of Position 90-7, *“Financial Reporting by Entities in Reorganization Under the Bankruptcy Code”*, or “SOP 90-7.”

For financial reporting purposes, the close of business on December 5, 2003, represents the date of emergence from bankruptcy. As used herein, the following terms refer to the Company and its operations:

“Predecessor Company”	The Company, pre-emergence from bankruptcy The Company’s operations, January 1, 2001 – December 5, 2003
“Reorganized NRG”	The Company, post-emergence from bankruptcy The Company’s operations, December 6, 2003 – December 31, 2003

The implementation of the NRG plan of reorganization resulted in, among other things, a new capital structure, the satisfaction or disposition of various types of claims against the Predecessor Company, the assumption or rejection of certain contracts, and the establishment of a new board of directors.

In connection with the emergence from bankruptcy, we adopted Fresh Start 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, the enterprise value of our company was allocated among our assets and liabilities on a basis substantially consistent with purchase accounting in accordance with SFAS No. 141 *“Business Combinations”*, or “SFAS No. 141.” Accordingly, we pushed down the effects of this allocation to all of our subsidiaries.

Under the requirements of Fresh Start, we have adjusted our assets and liabilities, other than deferred income taxes, to their estimated fair values as of December 5, 2003. As a result of marking our assets and liabilities to their estimated fair values, we determined that there was no excess reorganization value that was reallocated back to our tangible and intangible assets. Deferred taxes were determined in accordance with SFAS No. 109, *“Accounting for Income Taxes.”* The net effect of all Fresh Start adjustments resulted in a gain of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations), which is reflected in the Predecessor Company’s results of operations for the period January 1, 2003 through December 5, 2003. The application of the Fresh Start provisions of SOP 90-7 created a new reporting entity having no retained earnings or accumulated deficit.

As part of the bankruptcy process we engaged an independent financial advisor to assist in the determination of our reorganized enterprise value. The fair value calculation was based on management’s forecast of expected cash flows from our core assets. Management’s forecast incorporated forward commodity market prices obtained from a third party consulting firm. A discounted cash flow calculation was used to develop the enterprise value of Reorganized NRG, determined in part by calculating the weighted average cost of capital of the Reorganized NRG. The Discounted Cash Flow, or “DCF”, valuation methodology equates the value of an asset or business to the present value of expected future economic benefits to be generated by that asset or business. The DCF methodology is a “forward looking” approach that discounts expected future economic benefits by a theoretical or observed discount rate. The independent financial advisors prepared a 30-year cash flow forecast using a discount rate of approximately 11%. The resulting reorganization enterprise value as included in the Disclosure Statement ranged from $5.5 billion to $5.7 billion. The independent financial advisor then subtracted our project level debt and made several other adjustments to reflect the values of assets held for sale, excess cash and collateral requirements to estimate a range of Reorganized NRG equity value of between $2.2 billion and $2.6 billion.

In constructing our Fresh Start balance sheet upon our emergence from bankruptcy we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Our NRG Plan of reorganization provided for the issuance of 100,000,000 shares of NRG common stock to the various creditors resulting in a calculated price per share of $24.04. Our reorganization value of approximately $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. The reorganization value represents the fair value of an entity before liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after restructuring. This value is consistent with the voting creditors and bankruptcy court’s approval of the NRG plan of reorganization.

We recorded approximately $3.9 billion of net reorganization income (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations) in the Predecessor Company’s statement of operations for 2003, which includes the gain on the restructuring of equity and the discharge of obligations subject to compromise for less than recorded amounts, as well as adjustments to the historical carrying values of our assets and liabilities to fair market value.

Due to the adoption of Fresh Start as of December 5, 2003, the Reorganized NRG post-Fresh Start 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 therefore 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 and the Predecessor Company. The effects of the reorganization and Fresh Start on our balance sheet as of December 5, 2003, were as follows (in thousands):

	Predecessor Company December 5, 2003	Debt Discharge and Exchange of Stock	Fresh Start Adjustments		Consolidation	Reorganized NRG December 6, 2003
			(In thousands)			
Current Assets						
Cash and cash equivalents	$ 396,018	$ (1,728)(B)	$	$	$ 1,692 (T)	$ 395,982
Restricted cash	489,383	1,732 (B)			1,932 (T)	493,047
Accounts receivable — trade	208,677		(2)(B)	3,627 (J)	1,177 (T)	213,479
Accounts receivable — affiliates	41,259		819 (B)	(42,078)(J)		—
Xcel Energy settlement receivable		640,000 (A)				640,000
Current portion of notes receivable	66,628					66,628
Inventory	233,185		(25,945)(K)	(11,004)(L)		196,236
Derivative instruments valuation	161					161
Prepayments and other current assets	156,785	(25,855)(B)	(7,309)(M)	85,873 (J)	1,047 (T)	210,541
Current assets — discontinued operations	126,188		(1,241)(K)	1,629 (J)		126,576
Total current assets	1,718,284	614,149	(33,678)	38,047	5,848	2,342,650
Property, Plant and Equipment						
Net property, plant and equipment	5,247,375		(1,153,101)(I)	(132,128)(J)	46,652 (T)	4,008,798

	Predecessor Company December 5, 2003	Debt Discharge and Exchange of Stock	Fresh Start Adjustments		Consolidation	Reorganized NRG December 6, 2003
			(In thousands)			
Other Assets						
Equity investments in affiliates	956,757		(216,029)(C)	14 (J)	(6,880)(T)	733,862
Notes receivable, less current portion — affiliates	164,987		(39,336)(P)			125,651
Notes receivable, less current portion	752,847	(155,477)(D)	77,862 (P)		(301)(T)	674,931
Decommissioning fund investments	4,787					4,787
Intangible assets, net	70,275		437,222 (O)	(22,829)(I)		484,668
Debt issuance cost, net	67,045		(67,045)(P)			—
Derivative instruments valuation	66,442					66,442
Other assets, net	14,122		(37,891)(P)	98,857 (J)	2,170 (T)	108,744
				31,486 (J)		
Non-current assets — discontinued operations	826,715		(209,919)(P)			616,796
Total other assets	2,923,977	(155,477)	(55,136)	107,528	(5,011)	2,815,881
Total Assets	$ 9,889,636	$ 458,672	$(1,241,915)	$ 13,447	$ 47,489	$ 9,167,329
Current Liabilities						
Current portion of long-term debt	$ 1,433,551	$ (155,477)(D)	$ (89,182)(P)	$ 1,307,249 (Q)	$ 613 (T)	$ 2,496,754
Short-term debt			18,645 (P)			18,645
Accounts payable — trade	299,340	(101,632)(E)	(805)(N)	5,499 (J)		202,402
Accounts payable — affiliates	17,834	(2,308)(B)	(5,192)(N)	2,995 (J)	36 (T)	13,365
Accrued income tax	19,303		(7,127)(M)	4,255 (J)		16,431
Accrued property, sales and other taxes	30,180		(5,942)(B)	3,556 (J)		27,794
Accrued salaries, benefits and related costs	14,194			2,519 (J)	5 (T)	16,718
Accrued interest	76,485	(2,464)(B)		1,631 (J)	121 (T)	75,773
Derivative instruments valuation	95					95
Creditor pool obligation		1,040,000 (F)				1,040,000
Other bankruptcy settlement		220,000 (F)				220,000
Other current liabilities	135,274	57 (F)	11,800 (O)	(10,770)(J)	413 (T)	136,774
Current liabilities — discontinued operations	164,362		(51,679)(J)	6 (J)		112,689
Total Current Liabilities	2,190,618	998,176	(129,482)	1,316,940	1,188	4,377,440
Other Liabilities						
Long-term debt	849,192	10,000 (G)	(21,869)(P)	303 (J)	42,060 (T)	879,686
Deferred income taxes	146,120		(13,973)(M)	12,541 (J)		144,688
Postretirement and other benefit obligations	44,601	(1,118)(B)	64,067 (R)	(2,838)(J)		104,712
Derivative instruments valuation	53,082			102,627 (J)		155,709
Other long-term obligations	146,761	763 (B)	488,218 (O)	(99,060)(J)		536,682
Non-current liabilities — Discontinued operations	558,194		1,366 (M)			559,560
Total non-current liabilities	1,797,950	9,645	517,809	13,573	42,060	2,381,037
Total liabilities not subject to compromise	3,988,568	1,007,821	388,327	1,330,513	43,248	6,758,477
Total liabilities subject to compromise	7,658,071	(6,278,547)(H)	(1,367)(J)	(1,378,157)(Q)		—
Total liabilities	11,646,639	(5,270,726)	386,960	(47,644)	43,248	6,758,477
Stockholders' Equity/(Deficit)						
Minority interest	611				4,241 (T)	4,852

	Predecessor Company December 5, 2003	Debt Discharge and Exchange of Stock	Fresh Start Adjustments		Consolidation	Reorganized NRG December 6, 2003
			(In thousands)			
Commitments and Contingencies						
Class A — Common stock; $.01 par value; 100 shares authorized in 2002; 3 shares issued and outstanding at December 31, 2002	1	(1)(S)				—
Common stock; $.01 par value; 100 authorized in 2002; 1 share issued and outstanding at December 31, 2002	—					—
Common stock; $.01 par value; 500,000,000 authorized in 2003; 100,000,000 shares issued and outstanding at December 6, 2003	—	1,000 (H)				1,000
Additional paid-in capital	2,227,691	2,403,000 (H)	(2,227,691)(S)			2,403,000
Retained earnings/(deficit)	(3,986,739)		3,924,215 (S)	62,524 (S)		—
Accumulated other comprehensive income	1,433			(1,433)(S)		—
Total Stockholders' equity/ (deficit)	(1,757,614)	2,403,999	1,696,524	61,091		2,404,000
Total Liabilities and Stockholders' Equity/ (Deficit)	$ 9,889,636	$ (2,866,727)	$ 2,083,484	$13,447	$ 47,489	$ 9,167,329

(A) Represents a $640.0 million receivable from Xcel Energy that relates to the Xcel Energy Settlement Agreement. $288.0 million was paid on February 20, 2004 in cash and $352.0 million will be paid on April 30, 2004.

(B) Adjustments to assets and liabilities resulting from the NRG Energy bankruptcy settlement.

(C) Includes the adjustment of carrying amount of Investments in Projects to fair market value as determined by independent appraisers.

(D) The NRG Energy bankruptcy settlement included the liquidation of NRG FinCo. As a result, the NRG FinCo creditors obtained a perfected first priority security interest in all of LSP Pike Energy LLC assets, making the Mississippi Industrial Revenue Bonds owed by LSP Pike Energy LLC worthless.

(E) Includes $103.0 million discharge of obligations related to LSP Pike Energy LLC settlement with Shaw Constructors, Inc.

(F) Includes the establishment of a creditor's pool and the FinCo lender settlement (in millions):

Creditor installment payments	$ 515.0
Establishment of Plan of reorganization liability	500.0
Contingency payment	25.0
FinCo lender settlement (see Note 24)	220.0
Total other current liabilities	$1,260.0

(G) Represents NRG Energy Promissory Note owed to Xcel Energy, due June 5, 2006 with a stated interest rate of 3.0%

(H) Represents the elimination of approximately $5.2 billion of corporate level bank and bond debt and approximately $1.1 billion of additional claims and disputes by distributing a combination of equity and up to $1.04 billion in cash among our unsecured creditors. Upon reorganization we issued 100 million shares of NRG common stock at $24.04 per share.

(I) Result of allocating the reorganization value in conformity with the purchase method of accounting for business combinations. These allocations were based on valuations obtained from independent appraisers.

(J) Adoption of Fresh Start Reporting and reinstatement of miscellaneous liabilities subject to compromise.

(K) Accounting policy change upon adoption of fresh start reporting. Consumables are no longer included as inventory and are expensed as incurred.

(L) Accounting policy change upon adoption of fresh start reporting. Capital spares were reclassified from inventory to Property Plant and Equipment.

(M) Records income taxes of the Company based on the guidance provided in the Statement of Financial Accounting Standards No. 109 and SOP 90-7.

(N) Adjust assets and liabilities to reflect management's estimate, with the assistance of independent specialists, of the fair value.

(O) Reflects management's estimate, with the assistance of independent appraisers, of the fair value of power purchase agreements and SO(2) emission credits. Management identified certain power purchase agreements that were either significantly valuable or significantly burdensome as compared to our market expectations. The predecessor goodwill and intangibles were written off. Our guarantees were reviewed for the requirement to recognize a liability at inception. As a result, we recorded a $15.0 million liability. In addition, our Asset Retirement Obligation or "ARO" was revalued.

	(In millions)
SO(2) emission credits	$ 373.5
Valuable contracts	111.2
Predecessor intangible	(47.5)
Total intangible	$ 437.2
Burdensome contracts	$ 15.1
Other valuations adjustments	(3.3)
Total other current liabilities	$ 11.8
Burdensome contracts	$ 467.2
Other valuations adjustments	21.0
Total other long-term obligations	$ 488.2

(P) Reflects management's estimate, based on current market interest rates as of December 5, 2003, of the fair value of notes receivable, notes payable and other debt instruments.

(Q) Reclassification of subject to compromise liabilities due to emergence from bankruptcy consists primarily of the debt held at our Northeast and South Central subsidiaries of $1.3 billion. The remaining amounts were reclassified to current liabilities.

(R) Adjustment to post-retirement and other benefit obligations in order to reflect the accumulated benefit obligation liability based on independent actuarial reports. The pension and welfare plans were assumed from Xcel Energy without the transfer of assets.

(S) Reflects the cancellation of the Predecessor Company's common stock and the elimination of the retained deficit and the accumulated other comprehensive loss.

(T) As required by SOP 90-7, we have adopted FASB Interpretation No. 46 "Consolidation of Variable Interest Entities," or "FIN 46," as of the adoption of Fresh Start. The adoption of FIN 46 resulted in the consolidation of Northbrook New York, LLC and Northbrook Energy, LLC.

APB No. 18, *"The Equity Method of Accounting for Investments in Common Stock,"* requires us to effectively push down the effects of Fresh Start reporting to our unconsolidated equity method investments and to recognize an adjustment to our share of the earnings or losses of an investee as if the investee were a consolidated subsidiary. As a result of pushing down the impact of Fresh Start to our West Coast Power affiliate, we determined that a contract based intangible asset with a one year remaining life, consisting of the value of West Coast Power's California Department of Water Resources energy sales contract, must be established and recognized as a basis adjustment to our share of the future earnings generated by West Coast Power. This adjustment will reduce our equity earnings in the amount of approximately $10.4 million per month until the contract expires in December 2004.

Liquidity and Capital Resources

Reorganized Capital Structure

In connection with the consummation of the NRG plan of reorganization, on December 5, 2003 all shares of our old common stock were canceled and 100,000,000 shares of new common stock of NRG Energy were distributed pursuant to such plan to the holders of certain classes of claims. A certain number of shares of common stock were issued for distribution to holders of disputed claims as such claims are resolved or settled. In the event our disputed claims reserve is inadequate, it is possible we would have to issue additional shares of our common stock to satisfy such pre-petition claims or contribute additional cash proceeds. See Item 3 — Legal Proceedings — Disputed Claims Reserve. Our authorized capital stock consists of 500,000,000 shares of NRG Energy common stock and 10,000,000 shares of Serial Preferred Stock. Further, a total of 4,000,000 shares of our common stock, representing approximately 4% of our outstanding common stock, are available for issuance under our long-term incentive plan.

In addition to our issuance of new common stock, on December 23, 2003, we completed a note offering consisting of $1.25 billion of 8% Second Priority Senior Secured Notes due 2013, or the “Second Priority Notes”, and we entered into a new credit facility consisting of a $950.0 million term loan facility, a $250.0 million funded letter of credit facility and a $250.0 million revolving credit facility. In January of 2004, we completed a supplementary note offering whereby we issued an additional $475.0 million of the Second Priority Notes at a premium and used the proceeds to repay a portion of the $950.0 million term loan. As of March 1, 2004, we had $1.7 billion in aggregate principal amount of Second Priority Notes outstanding, $446.5 million principal amount outstanding under the term loan and $147.5 million remains available under the funded letter of credit facility. As of March 1, 2004, we had not drawn down on our revolving credit facility. Finally, in connection with the consummation of the NRG plan of reorganization, we issued to Xcel Energy a $10.0 million non-amortizing promissory note, which will accrue interest at a rate of 3% per annum and mature 2.5 years after the effective date of the NRG plan of reorganization.

As part of the NRG plan of reorganization, we eliminated approximately $5.2 billion of corporate level bank and bond debt and approximately $1.3 billion of additional claims and disputes through our distribution of new common stock and $1.04 billion in cash among our unsecured creditors. In addition to the debt reduction associated with the restructuring, we used the proceeds of the recent note offering and borrowings under the New Credit Facility to retire approximately $1.7 billion of project-level debt.

For additional information on our short term and long term borrowing arrangements, see Item 15 — Note 17 to the Consolidated Financial Statements.

Historical Cash Flows

Predecessor Company

Historically, we have obtained cash from operations, issuance of debt and equity securities, borrowings under credit facilities, capital contributions from Xcel Energy, reimbursement by Xcel Energy of tax benefits pursuant to a tax sharing agreement and proceeds from non-recourse project financings. We used these funds to finance operations, service debt obligations, fund the acquisition, development and construction of generation facilities, finance capital expenditures and meet other cash and liquidity needs.

Reorganized NRG

We have obtained cash from operations, Xcel Energy's contribution net of distributions to creditors, proceeds from the sale of certain assets and borrowings under our Second Priority Notes and New Credit Facility.

	Predecessor Company			Reorganized NRG
	Year Ended December 31,		For the Period January 1 — December 5, 2003	For the Period December 6 — December 31, 2003
	2001	2002		
	(In thousands)			
Net cash provided (used) by operating activities	$ 276,014	$ 430,042	$ 238,509	**$ (588,875)**
Net cash (used) provided by investing activities	(4,335,641)	(1,681,467)	(185,679)	**363,372**
Net cash provided (used) by financing activities	4,153,546	1,449,330	(29,944)	**393,273**

Net Cash Provided (Used) By Operating Activities

Predecessor Company

Net cash provided by operating activities increased during 2002 compared with 2001, primarily due to our efforts to conserve cash by deferring the payment of interest and managing our cash flows more closely. As a result, we increased accounts payable and accrued interest balances and reduced inventory levels.

For the period January 1, 2003 through December 5, 2003 net cash provided by operating activities was $238.5 million. Operating activities consisted of a net loss before Fresh Start adjustments of $1.1 billion, offset by non-cash charges of $567.5 million and cash provided by working capital of $800.1 million. The non-cash charges consisted primarily of the write-down of our investment in Loy Yang, asset impairments and legal settlement charges. The favorable change in working capital was primarily due to reduced cash expenditures throughout the bankruptcy period resulting in increased accounts payable.

Reorganized NRG

For the period December 6, 2003 through December 31, 2003 cash used by operating activities was $588.9 million. This was primarily a result of payments made to creditors upon our emergence from bankruptcy.

Net Cash Provided (Used) By Investing Activities

Predecessor Company

Net cash used in investing activities decreased in 2002, compared with 2001, primarily as a result of the termination of our acquisition program due to our financial difficulties and the receipt of cash upon the sale of assets during 2002.

For the period January 1, 2003 through December 5, 2003 cash used in investing activities $185.7 million. This was primarily a result of capital expenditures and an increase in restricted cash, offset by cash proceeds received upon the sale of investments.

Reorganized NRG

For the period December 6, 2003 through December 31, 2003 cash provided by investing activities was $363.4 million. In connection with the refinancing transaction, approximately $375.3 million of restricted cash was released upon payment of the Northeast Generating and South Central Generating note. This increase was offset by funds used for capital expenditures and investments in projects.

Net Cash Provided (Used) By Financing Activities

Predecessor Company

Net cash provided by financing activities decreased during 2002 compared to 2001 due to constraints on our ability to access the capital markets and the cancellation and termination of construction projects reducing the need for capital.

For the period January 1, 2003 through December 5, 2003 cash used by financing activities was $29.9 million, which consisted primarily of principal payments offset by the issuance of additional debt.

Reorganized NRG

For the period December 6, 2003 through December 31, 2003 cash provided by financing activities was $393.3 million. We entered into refinancing transactions on December 23, 2003, where we issued $1.25 billion of Second Priority Notes and entered into the New Credit Facility, which consisted of a $950.0 million senior secured term loan facility and a $250.0 million funded letter of credit facility. Upon completion of the refinancing transactions, we repaid the Northeast Generating and South Central Generating notes and the Mid-Atlantic Generating obligations.

Sources of Funds

The principal sources of liquidity for our future operations, capital expenditures, facility closures and project restructurings are expected to be: (i) existing cash on hand and cash flows from operations, (ii) Xcel Energy’s contribution net of distributions to creditors, (iii) proceeds from the sale of certain assets and businesses and (iv) borrowings under our New Credit Facility, including up to $250.0 million of available borrowings under our new revolving credit facility and up to $250.0 million of a pre-funded letter of credit facility. Additionally, there are approximately $89.5 million of undrawn letters of credit under the pre-petition ANZ LC Facility. The ANZ LC Facility is supported by a cash funded claim reserve to support any letters of credit drawn prior to their expiration.

Capacity under the ANZ LC facility will be reduced as the underlying LCs expire or are terminated. All of the LCs will expire or be terminated by the end of 2004, at which time the ANZ LC facility will no longer exist.

As a result of our emergence from bankruptcy, all of our then existing securities, including our old common stock and various issuances of senior notes, were cancelled and approximately $5.2 billion of our existing debt and approximately $1.3 billion of additional claims and disputes were eliminated for a combination of equity and up to $1.04 billion in cash.

On December 23, 2003, we entered into a bank facility for up to $1.45 billion, or the “New Credit Facility”, which included a $950.0 million, six and a half-year senior secured term loan, a $250.0 million funded letter of credit facility, and a four-year $250.0 million revolving line of credit, or the “revolving credit facility.” Portions of the revolving credit facility are available as a swing-line facility and as a revolving letter of credit sub-facility. As of December 31, 2003, the corporate revolver was undrawn. Also on December 23, 2003, we issued $1.25 billion in 8% second priority, senior secured notes, or the “Second Priority Notes”, due and payable on December 15, 2013.

Upon completion of the refinancing transactions, we, among other things: (i) repaid the Northeast Generating LLC Notes, or “Northeast Notes”, the South Central Generating LLC Notes, or “South Central Notes”, and the Mid-Atlantic Generating LLC Obligations; (ii) paid a settlement amount associated with the repayment of the Northeast Notes and the South Central Notes; (iii) paid $500.0 million in lieu of 10% NRG Energy senior notes to former unsecured creditors pursuant to the NRG plan of reorganization, the “POR Notes”, (see the discussion of Senior Securities under Item 15 — Note 17 to the Consolidated Financial Statements); (iv) pre-funded a letter of credit sub-facility under the New Credit Facility in the amount of $250.0 million; and (v) paid fees and expenses related to the offering of notes and the New Credit Facility in the amount of $74.8 million.

On January 28, 2004, we issued an additional $475.0 million of the Second Priority Notes, obtaining net proceeds of $501.8 million. With proceeds from this issuance and other funds, we subsequently 1) repaid $503.5 million of the term loan under the New Credit Facility, reducing the principal outstanding from $950.0 million to $446.5 million, 2) made a prepayment premium payment of $15.1 million, and 3) repaid accrued but unpaid interest on the prepayment amount, totaling $0.4 million. On February 25, 2004, we received from our term loan lenders a waiver under the New Credit Facility waiving our obligation to enter into a hedge arrangement on a notional value of $500.0 million, as required by the credit agreement.

Cash Flows. Our operating cash flows are expected to be impacted by, among other things: (i) spark spreads generally; (ii) commodity prices (including demand for natural gas, coal, oil and electricity); (iii) the cost of ordinary course operations and maintenance expenses; (iv) planned and unplanned outages; (v) contraction of terms by trade creditors; (vi) cash requirements for closure and restructuring of certain facilities; (vii) restrictions in the declaration or payments of dividends or similar distributions from our subsidiaries; and (viii) the timing and nature of asset sales.

A principal component of the NRG plan of reorganization is a settlement with Xcel Energy in which Xcel Energy agreed to make a contribution to us consisting of cash (and, under certain circumstances, its common stock) in an aggregate amount of up to $640.0 million to be paid in three separate installments. Xcel Energy contributed $288.0 million on February 20, 2004. We anticipate receiving an additional installment of up to $352.0 million in cash on April 30, 2004. We will distribute $515.0 million of cash we receive from Xcel Energy to our creditors. In the event we achieve certain liquidity measures in September 2004, an additional $25.0 million may be distributed to creditors, and we may use $100.0 million for any purpose, subject to any restrictions contained in the indenture or the New Credit Facility.

Asset Sales. We received $229.3 million and $196.2 million in net cash proceeds from the sale of certain assets and businesses in the fiscal years ended 2002 and 2003, respectively. The New Credit Facility and the indenture governing the notes place restrictions on the use of any proceeds we may receive from certain asset sales in the future.

Letter of Credit Sub-facility and Revolving Credit Facility. The New Credit Facility includes a letter of credit sub-facility in the amount of $250.0 million. As of December 31, 2003, we had issued $1.7 million in letters of credit under this facility. The New Credit Facility also includes a revolving credit facility in the amount of $250.0 million to be used for general corporate purposes. On December 31, 2003 we had not yet drawn on our revolving credit facility. For additional information regarding our debt see Item 15 — Note 17 to the Consolidated Financial Statements.

Uses of Funds

Our requirements for liquidity and capital resources, other than for operating our facilities, can generally be categorized by the following: (i) PMI activities; (ii) capital expenditures; and (iii) project finance requirements for cash collateral.

PMI. PMI activities comprise the single largest requirement for liquidity and capital resources. PMI liquidity requirements are primarily driven by: (i) margin and collateral posting requirements with counterparties; (ii) establishment of trading relationships; (iii) disbursement and receipt timing (i.e., buying fuel before receiving energy revenues); and (iv) initial collateral for large structured transactions. For 2004, we believe that approximately $265 million to $360 million may be required for PMI to meet potential margin requirements and to cover prepayments and fuel inventory builds.

Estimates for liquidity requirements are highly dependent on our hedging activity and then current market conditions, including forward prices for energy and fuel and market volatility. In addition, our estimates are dependent on credit terms with third parties. We do not assume that we will be provided with unsecured credit from third parties in budgeting our working capital requirements.

Capital Expenditures. Capital expenditures were $1.4 billion for the year ended 2002, $113.5 million for the period January 1, 2003 through December 5, 2003 and $10.6 million for the period December 6, 2003 through December 31, 2003. Capital expenditures in 2003 relate primarily to operations and maintenance of our existing generating facilities whereas capital expenditures in 2002 related primarily to new plant construction. We anticipate that our 2004 capital expenditures will be approximately $113.8 million and will relate primarily to the operation and maintenance of our existing generating facilities.

Project Finance Requirements. We are a holding company and conduct our operations through subsidiaries. Historically, we have utilized non-recourse debt to fund a significant portion of the capital expenditures and investments required to construct our power plants and related assets. Consistent with our strategy, we may seek, where available on commercially reasonable terms, non-recourse debt financing in connection with the assets or businesses that our affiliates or we may develop, construct or acquire. Non-recourse borrowings are substantially non-recourse to other subsidiaries, affiliates and us, and are generally secured by the capital stock, physical assets, contracts and cash flow of the related project subsidiary or affiliate. Some of these project financings require us to post collateral in the form of cash or an acceptable letter of credit.

Principal on short-term debt, long-term debt and capital leases as of December 31, 2003 are due and payable in the following periods (in thousands):

Subsidiary/Description	Total	2004	2005	2006	2007	2008	Thereafter
$250 Million Revolver Due Dec 2007	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Xcel Energy Note	10,000	—	—	10,000		—	—
Credit Facility Due June 2010	1,200,000	12,000	12,000	12,000	12,000	12,000	1,140,000
8% Senior Secured Notes due Dec. 2013	1,250,000	—	—	—	—	—	1,250,000
MEC Corp.	126,279	7,329	7,876	8,465	9,097	9,777	83,735
NRG Peaker Finance Co LLC	311,373	311,373	—	—	—	—	—
LSP — Kendall Energy	487,013	487,013	—	—	—	—	—
Flinders Power Finance Pty	187,668	—	9,292	12,436	13,538	14,737	137,665
Pittsburgh Thermal LP	1,550	1,550	—	—	—	—	—
San Francisco Thermal LP	860	729	31	34	37	29	—
Meridan	500	500	—	—	—	—	—
Camas Pwr BLR LP Bank facility	8,628	2,352	2,443	2,533	1,300	—	—
Camas Pwr BLR LP Bonds	5,765	1,290	1,385	1,485	1,605	—	—
Northbrook New York	17,199	300	500	600	700	800	14,299
Northbrook Carolina	2,475	100	100	100	150	150	1,875
Northbrook STS HydroPower	24,506	436	477	523	572	627	21,871
Subtotal Debt, Bonds and Notes	3,633,816	824,972	34,104	48,176	38,999	38,120	2,649,445

Subsidiary/Description	Total	2004	2005	2006	2007	2008	Thereafter
Saale Energie GmbH, Schkopau (capital lease)	342,469	75,944	78,580	43,858	33,075	27,039	83,973
Audrain Generating (capital lease)	239,930	—	—	—	—	—	239,930
NRG Processing Solutions, LLC (capital lease)	326	326	—	—	—	—	—
Subtotal Capital Leases	582,725	76,270	78,580	43,858	33,075	27,039	323,903
Itiquira	19,019	19,019	—	—	—	—	—
Discontinued Operations							
LSP Energy LP (Batesville)	307,175	7,575	9,600	11,925	12,525	12,825	252,725
Hsin Yu Energy Development	85,300	85,300	—	—	—	—	—
PERC (Bonds)	26,265	1,735	1,820	1,910	2,005	2,110	16,685
Cobee	31,800	11,025	11,535	4,620	4,620	—	—
McClain	156,509	156,509	—	—	—	—	—
Subtotal Discontinued Operations	607,049	262,144	22,955	18,455	19,150	14,935	269,410
Total Debt	$4,842,609	$1,182,405	$135,639	$110,489	$91,224	$80,094	$3,242,758

Principal payments for debt that have been deemed current for financial reporting purposes as of December 31, 2003 are reflected as short-term in the table above. Events may have occurred since December 31, 2003 that would allow such debt to be paid on a normal amortizing schedule. Prepayments, or additional borrowing under certain facilities, since December 31, 2003 are not reflected. See Item 15 — Note 17 to the Consolidated Financial Statements for further discussion on events that may affect debt payment schedules.

If we decide not to provide any additional funding or credit support to our subsidiaries, the inability of any of our subsidiaries that are under construction or that have near-term debt payment obligations to obtain non-recourse project financing may result in such subsidiary's insolvency and the loss of our investment in such subsidiary. Additionally, the loss of a significant customer at any of our subsidiaries may result in the need to restructure the non-recourse project financing at that subsidiary, and the inability to successfully complete a restructuring of the non-recourse project financing may result in a loss of our investment in such subsidiary. Certain of our projects are subject to restrictions regarding the movement of cash. For additional information see Item 15 — Note 17 to the Consolidated Financial Statements.

Liquidity Estimates

For 2004, we anticipate utilizing all of our $250.0 million letter of credit sub-facility. In addition, we believe that approximately $265.0 million to $360.0 million of cash may be required for PMI to meet its potential margin requirements and to cover prepayments and fuel inventory builds. As part of our refinancing transactions, we have established a $250.0 million revolving credit facility. The revolving credit facility was established to satisfy short-term working capital requirements, which may arise from time to time. It is not our current intention to draw funds under the revolving credit facility.

Other Liquidity Matters

We maintain cash deposits in order to assure the continuation of vendor trade terms. As of December 31, 2003, the total amount of cash deposits maintained for these purposes was approximately $48.3 million.

We expect our capital requirements to be met with existing cash balances, cash flows from operations, borrowings under our Second Priority Notes and New Credit Facility, and asset sales. We believe that our current level of cash availability and asset sales, along with our future anticipated cash flows from operations, will be sufficient to meet the existing operational and collateral needs of our business for the next 12 months.

Subject to restrictions in our Second Priority Notes and our New Credit Facility, if cash generated from operations is insufficient to satisfy our liquidity requirements, we may seek to sell assets, obtain additional credit facilities or other financings and/or issue additional equity or convertible instruments. We cannot assure you, however, that our business will generate sufficient cash flow from operations, that currently anticipated cost savings and operating improvements will be realized on schedule or that future borrowings will be available to us under our credit facilities in an amount sufficient to enable us to pay our indebtedness, or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness, on or before maturity. We cannot assure you that we will be able to refinance any of our indebtedness, on commercially reasonable terms or at all. To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control.

Net Operating Loss Carryforwards

During 2002 and 2003 we generated a net operating loss carryforward of $1.0 billion which will expire in 2023. We have assessed the likelihood that a substantial portion of the 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. Accordingly, 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 the 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 depreciation in future years.

Off Balance-Sheet Items

As of December 31, 2003, we do not have any significant relationships with structured finance or special purpose entities that provide liquidity, financing or incremental market risk or credit risk.

We have numerous investments with an ownership interest percentage of 50% or less in energy and energy related entities that are accounted for under the equity method of accounting as disclosed in Item 15 — Note 13 to the Consolidated Financial Statements. Our pro-rata share of non-recourse debt held by unconsolidated affiliates was approximately $967.7 million as of December 31, 2003. In the normal course of business we may be asked to loan funds to these entities on both a long and short-term basis. Such transactions are generally accounted for as accounts payables and receivables to/from affiliates and notes payables/receivables to/from affiliates and if appropriate, bear market-based interest rates. See Item 15 — Note 11 to the Consolidated Financial Statements for additional information regarding amounts accounted for as notes receivable — affiliates.

Contractual Obligations and Commercial Commitments

We have a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to our capital expenditure programs. The following is a summarized table of contractual obligations. See additional discussion in Item 15 — Notes 17, 24 and 26 to the Consolidated Financial Statements.

Contractual Cash Obligations	Total	Short Term	1-3 Years	4-5 Years	After 5 Years
	Payments Due by Period as of December 31, 2003				
			(In thousands)		
Long-term debt**	$3,633,816	$ 824,972	$ 82,280	$ 77,119	$2,649,445
Capital lease obligations	582,725	76,270	122,438	60,114	323,903
Operating leases***	45,625	8,760	14,799	7,132	14,934
Creditor payments*	540,000	540,000	—	—	—
Total contractual cash obligations	$4,802,166	$1,450,002	$219,517	$144,365	$2,988,282

* These amounts represent creditor payments under NRG's plan of reorganization. Additionally, payments of up to $275 million will be required pursuant to security interests held in certain assets by creditors when the related assets are sold.

** Long-term debt excludes debt recorded at our McClain, PERC, Cobee, LSP and Hsin Yu projects in the amounts of $156.5 million, $26.3 million, $31.8 million, $307.2 million and $85.3 million, respectively, which have been reclassified as discontinued operations.

*** Operating leases excludes obligations for operating leases at our Hsin Yu and Cobee projects in the amounts of $1.8 million and $0.1 million, respectively.

Other Commercial Commitments	Total Amounts Committed	Short Term	1-3 Years	4-5 Years	After 5 Years
	Amount of Commitment Expiration per Period as of December 31, 2003				
			(In thousands)		
Lines of credit	$ —	$ —	$ —	$ —	$ —
Standby letters of credit	92,050	92,050	—	—	—
Cash collateral calls	71,472	71,472	—	—	—
Guarantees of Subsidiaries	506,935	—	19,490	778	486,667
Guarantees of PMI	57,179	5,000	52,179	—	—
Total commercial commitments	$727,636	$168,522	$71,669	$ 778	$486,667

Interdependent Relationships

We do not have any significant interdependent relationships. Since we formerly were an indirect wholly owned subsidiary of Xcel Energy, there were certain related party transactions that took place in the normal course of business. For additional information regarding our related party transactions, see Item 15 — Note 22 to the Consolidated Financial Statements.

Derivative Instruments

We may enter into long-term power sales contracts, long-term gas purchase contracts and other energy related commodities financial instruments to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and protect fuel inventories.

The tables below disclose the trading activities that include non-exchange traded contracts accounted for at fair value. Specifically, these tables disaggregate realized and unrealized changes in fair value; identify changes in fair value attributable to changes in valuation techniques; disaggregate estimated fair values at December 31, 2003 based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at December 31, 2003.

Table of Contents

Trading Activity Gains/(Losses)

	Predecessor Company	Reorganized NRG
	(In thousands)	
Fair value of contracts at December 31, 2001	$ 72,236	
Contracts realized or otherwise settled during the period	(119,061)	
Other changes in fair value	77,465	
Fair value of contracts at December 31, 2002	30,640	
Contracts realized or otherwise settled during the period	(187,603)	
Other changes in fair value	112,865	
Fair value of contracts at December 5, 2003	$ (44,098)	
Fair value of contracts at December 6, 2003		**$ (44,098)**
Contracts realized or otherwise settled during the period		**(2,390)**
Other changes in fair value		**(3,426)**
Fair value of contracts at December 31, 2003		**$ (49,914)**

Sources of Fair Value Gains/(Losses)

	Reorganized NRG Fair Value of Contracts at Period End as of December 6, 2003				
	Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in excess of 5 Years	Total Fair Value
			(In thousands)		
Prices actively quoted	$ 42,107	$ (7,022)	$ (10,820)	$ (68,363)	$ (44,098)
	$ 42,107	$ (7,022)	$ (10,820)	$ (68,363)	$ (44,098)

	Reorganized NRG Fair Value of Contracts at Period End as of December 31, 2003				
	Maturity Less than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in excess of 5 Years	Total Fair Value
			(In thousands)		
Prices actively quoted	$ 34,462	$ (6,860)	$ (8,570)	$ (68,946)	$ (49,914)
	$ 34,462	$ (6,860)	$ (8,570)	$ (68,946)	$ (49,914)

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

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements and related disclosures in compliance with generally accepted accounting principles, or “GAAP”, requires the application of appropriate technical accounting rules and guidance as well as the use of estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies have not changed.

On an ongoing basis, we, evaluate our estimates, utilizing historic experience, consultation with experts and other methods we consider reasonable. In any case, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Our significant accounting policies are summarized in Item 15 — Note 2 to the Consolidated Financial Statements. The following table identifies certain of the significant accounting policies listed in Item 15 — Note 2 to the Consolidated Financial Statements. The table also identifies the judgments required, uncertainties involved in the application of each and estimates that may have a material impact on our results of operations and statement of financial position. These policies, along with the underlying assumptions and judgments made by our management in their application, have a significant impact on our consolidated financial statements. We identify our most critical accounting policies as those that are the most pervasive and important to the portrayal of our financial position and results of operations, and that require the most difficult, subjective and/or complex judgments by management regarding estimates about matters that are inherently uncertain.

Accounting Policy		Judgments/ Uncertainties Affecting Application
Fresh Start Reporting	•	The determination of the enterprise value and the allocation to the underlying assets and liabilities are based on a number of estimates and assumptions, which are inherently subject to significant uncertainties and contingencies
	•	Determination of enterprise value
	•	Determination of Fresh Start date
	•	Consolidation of entities remaining in bankruptcy
	•	Valuation of emission credit allowances and power sales contracts
	•	Valuation of debt instruments
	•	Valuation of equity investments
Capitalization Practices/ Purchase Accounting	•	Determination of beginning and ending of capitalization periods
	•	Allocation of purchase prices to identified assets
Asset Valuation and Impairment	•	Recoverability of investment through future operations
	•	Regulatory and political environments and requirements
	•	Estimated useful lives of assets
	•	Environmental obligations and operational limitations
	•	Estimates of future cash flows
	•	Estimates of fair value (fresh start)
	•	Judgment about triggering events
Inventory	•	Valuation of inventory balances
Foreign Currency Translation	•	Recognition of changes in foreign currencies.
Revenue Recognition	•	Customer/counter-party dispute resolution practices
	•	Market maturity and economic conditions
	•	Contract interpretation

Accounting Policy		Judgments/ Uncertainties Affecting Application
Uncollectible Receivables	•	Economic conditions affecting customers, counter parties, suppliers and market prices
	•	Regulatory environment and impact on customer financial condition
	•	Outcome of litigation and bankruptcy proceedings
Derivative Financial Instruments	•	Market conditions in the energy industry, especially the effects of price volatility on contractual commitments
	•	Assumptions used in valuation models
	•	Counter party credit risk
	•	Market conditions in foreign countries
	•	Regulatory and political environments and requirements
Litigation Claims and Assessments	•	Impacts of court decisions
	•	Estimates of ultimate liabilities arising from legal claims
Income Taxes and Valuation Allowance for Deferred Tax Assets	•	Ability of tax authority decisions to withstand legal challenges or appeals
	•	Anticipated future decisions of tax authorities
	•	Application of tax statutes and regulations to transactions.
	•	Ability to utilize tax benefits through carrybacks to prior periods and carryforwards to future periods.
Discontinued Operations	•	Consistent application
	•	Determination of fair value (recoverability)
	•	Recognition of expected gain or loss prior to disposition
Pension	•	Accuracy of management assumptions
	•	Accuracy of actuarial consultant assumptions
Stock-Based Compensation	•	Accuracy of management assumptions used to determine the fair value of the stock options

Of all of the accounting policies identified in the above table, we believe that the following policies and the application thereof to be those having the most direct impact on our financial position and results of operations.

Fresh Start Reporting

In connection with the emergence from bankruptcy, we adopted Fresh Start 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, the reorganization value of our company was allocated among our assets and liabilities on a basis substantially consistent with purchase accounting in accordance with SFAS No. 141 *"Business Combinations."*

The bankruptcy court in its confirmation order approved our Plan of reorganization on November 24, 2003. Under the requirements of SOP 90-7, the Fresh Start date is determined to be the confirmation date unless significant uncertainties exist regarding the effectiveness of the bankruptcy order. Our Plan of reorganization required completion of the Xcel Energy settlement agreement prior to emergence from bankruptcy. We believe this settlement agreement was a significant contingency and thus delayed the Fresh Start date until the Xcel Energy settlement agreement was finalized on December 5, 2003.

Under the requirements of Fresh Start, we have adjusted our assets and liabilities, other than deferred income taxes, to their estimated fair values as of December 5, 2003. As a result of marking our assets and liabilities to their estimated fair values, we determined that there was no excess reorganization value to recognize as an intangible asset. Deferred taxes were determined in accordance with SFAS No. 109, *"Accounting for Income Taxes."* The net effect of all Fresh Start adjustments resulted in a gain of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations), which is reflected in the Predecessor Company's results for the period January 1, 2003 through December 5, 2003. The application of the Fresh Start provisions of SOP 90-7 created a new reporting entity having no retained earnings or accumulated deficit.

As part of the bankruptcy process we engaged an independent financial advisor to assist in the determination of the fair value of our reorganized enterprise value. The fair value calculation was based on management's forecast of our core assets. Management's forecast relied on forward market prices obtained from a third party consulting firm. A discounted cash flow calculation was used to develop the enterprise value of Reorganized NRG, determined in part by calculating the weighted average cost of capital of the Reorganized NRG. The Discounted Cash Flow, or "DCF", valuation methodology equates the value of an asset or business to the present value of expected future economic benefits to be generated by that asset or business. The DCF methodology is a "forward looking" approach that discounts all expected future economic benefits by a theoretical or observed discount rate determined by calculating the weighted average cost of capital, or "WACC", of Reorganized NRG. The enterprise calculation was based on management's forecast of our core assets. Management's forecast relied on forward market prices obtained from a third party consulting firm. For purposes of our Disclosure statement, the independent financial advisor estimated our reorganization enterprise value of our ongoing projects to range from $5.5 billion to $5.7 billion, less project level debt, and net of cash. Certain other adjustments were made to reflect the values of assets held for sale, excess cash and net of the Xcel Settlement and collateral requirements. These adjustments resulted in a reorganized NRG value, net of project debt, of between $3.1 billion and $3.5 billion. Additional adjustments were made to reflect cash payments expected as part of the implementation of the Plan of Reorganization, resulting in a final range of equity values of between $2.2 billion and $2.6 billion.

In constructing our Fresh Start balance sheet upon our emergence from bankruptcy we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Our reorganization value of approximately $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. The reorganization value represents the fair value of an entity before liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after restructuring. This value is consistent with the voting creditors and Court's approval of the Plan of Reorganization.

A separate plan of reorganization was filed for our Northeast Generating and South Central Generating entities that was confirmed by the bankruptcy court on November 25, 2003, and became effective on December 23, 2003, when the final conditions of the plan were completed. In connection with Fresh Start on December 5, 2003, we have accounted for these entities as if they had emerged from bankruptcy at the same time that we emerged, as we believe that we continued to maintain control over the Northeast Generating and South Central Generating facilities throughout the bankruptcy process.

Due to the adoption of Fresh Start upon our emergence from bankruptcy, the Reorganized NRG's post-fresh start 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 therefore not comparable in certain respects to the financial statements prior to the application of Fresh Start.

Capitalization Practices and Purchase Accounting

Predecessor Company

For those assets that were being constructed by us, the carrying value reflects the application of our property, plant and equipment policies which incorporate estimates, assumptions and judgments by management relative to the capitalized costs and useful lives of our generating facilities. Interest incurred on funds borrowed to finance projects expected to require more than three months to complete is capitalized. Capitalization of interest is discontinued when the asset under construction is ready for our intended use or when construction is terminated. An insignificant amount of interest was capitalized during 2003. Development costs and capitalized project costs include third party professional services, permits and other costs that are incurred incidental to a particular project. Such costs are expensed as incurred until an acquisition agreement or letter of intent is signed, and our board of directors has approved the project. Additional costs incurred after this point are capitalized.

Reorganized NRG

In connection with the emergence from bankruptcy, we adopted Fresh Start 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, the reorganization value of our company was allocated to our assets and liabilities on a basis substantially consistent with purchase accounting in accordance with SFAS No. 141. We engaged a valuation specialist to help us determine the fair value of our fixed assets. The valuations were based on forecast power prices and operating costs determined by us. The valuation specialist also determined the estimated remaining useful lives of our fixed assets. The capitalization policy will be consistent with the predecessor company policy.

Impairment of Long Lived Assets

We evaluate property, plant and equipment and intangible assets for impairment whenever indicators of impairment exist. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of the assets to the future net cash flows expected to be generated by the asset, through considering project specific assumptions for long-term power pool prices, escalated future project operating costs and expected plant operations. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets by factoring in the probability weighting of different courses of action available to us. Generally, fair value will be determined using valuation techniques such as the present value of expected future cash flows. Assets to be disposed of are reported at the lower of the carrying amount or fair value less the cost to sell. For the period January 1, 2003 through December 5, 2003, net income from continuing operations was reduced by $228.9 million due to asset impairments. Asset impairment evaluations are by nature highly subjective.

Revenue Recognition and Uncollectible Receivables

We are primarily an electric generation company, operating a portfolio of majority-owned electric generating plants and certain plants in which our ownership is 50% or less which are accounted for under the equity method of accounting. We also produce thermal energy for sale to customers. Both physical and financial transactions are entered into to optimize the financial performance of our generating facilities. Electric energy revenue is recognized upon transmission to the customer. In certain markets, which are operated/controlled by an independent system operator and in which we have entered into a netting agreement with the ISO, which results in our receiving a netted invoice, we have recorded purchased energy as an offset against revenues received upon the sale of such energy. Capacity and ancillary revenue is recognized when contractually earned. Revenues from operations and maintenance services are recognized when the services are performed. We continually assess the collectibility of our receivables, and in the event we believe a receivable to be uncollectible, an allowance for doubtful accounts is recorded or, in the event of a contractual dispute, the receivable and corresponding revenue may be considered unlikely of recovery and not recorded in the financial statements until management is satisfied that it will be collected.

Derivative Financial Instruments

In January 2001, we adopted FAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities,"* or "SFAS No. 133", as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 149. SFAS No. 133 requires us to record all derivatives on the balance sheet at fair value. In some cases hedge accounting may apply. The criteria used to determine if hedge accounting treatment is appropriate are a) the designation of the hedge to an underlying exposure, b) whether or not the overall risk is being reduced and c) if there is correlation between the value of the derivative instrument and the underlying obligation. Formal documentation of the hedging relationship, the nature of the underlying risk, the risk management objective, and the means by which effectiveness will be assessed is created at the inception of the hedge. Changes in the fair value of non-hedge derivatives are immediately recognized in earnings. Changes in the fair value of derivatives accounted for as hedges are either recognized in earnings as an offset to the changes in the fair value of the related hedged assets, liabilities and firm commitments or for forecasted transactions, deferred and recorded as a component of accumulated other comprehensive income or "OCI", until the hedged transactions occur and are recognized in earnings. We primarily account for derivatives under SFAS No. 133 such as long-term power sales contracts, long-term gas purchase contracts and other energy related commodities and financial instruments used to mitigate variability in earnings due to fluctuations in spot market prices, hedge fuel requirements at generation facilities and to protect investments in fuel inventories. SFAS No. 133 also applies to interest rate swaps and foreign currency exchange rate contracts. The application of SFAS No. 133 results in increased volatility in earnings due to the recognition of unrealized gains and losses. In determining the fair value of these derivative/financial instruments we use estimates, various assumptions, judgment of management and when considered appropriate third party experts in determining the fair value of these derivatives.

Discontinued Operations

We classify our results of operations that either have been disposed of or are classified as held for sale as discontinued operations if both of the following conditions are met: (a) the operations and cash flows have been (or will be) eliminated from our ongoing operations as a result of the disposal transaction and (b) we will not have any significant continuing involvement in the operations of the component after the disposal transaction. Prior periods are restated to report the operations as discontinued.

Pensions

The determination of our obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets and the rate of future compensation increases. Our actuarial consultants use assumptions for such items as retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of pension obligation or expense recorded by us.

Stock-Based Compensation

Effective January 1, 2003, we adopted the fair value recognition provisions of SFAS Statement No. 123, *"Accounting for Stock-Based Compensation,"* or "SFAS No. 123." In accordance with SFAS Statement No. 148, *"Accounting for Stock-Based Compensation — Transition and Disclosure,"* or "SFAS No. 148", we adopted SFAS No. 123 under the prospective transition method which requires the application of the recognition provisions to all employee awards granted, modified, or settled after the beginning of the fiscal year in which the recognition provisions are first applied.

Recent Accounting Developments

As part of the provisions of SOP 90-7, we are required to adopt, for the current reporting period, all accounting guidance that is effective within a twelve-month period. As a result, we have adopted all provisions of FASB Interpretation No. 46R, "Consolidation of Variable Interest Entities."

PART IV

Item 15 — *Exhibits, Financial Statement Schedules and Reports on Form 8-K*

(a)(1) Financial Statements

The following consolidated financial statements of NRG Energy and related notes thereto, together with the reports thereon of PricewaterhouseCoopers LLP are included herein:

Consolidated Statements of Operations — Years ended December 31, 2001 and 2002 and for the period January 1, 2003 to December 5, 2003 (Predecessor Company) and the period December 6, 2003 to December 31, 2003 (Reorganized NRG)

Consolidated Balance Sheets — December 31, 2002 (Predecessor Company), December 6, 2003 and December 31, 2003 (Reorganized NRG)

Consolidated Statements of Cash Flows — Years ended December 31, 2001 and 2002 and for the period January 1, 2003 to December 5, 2003 (Predecessor Company) and the period December 6, 2003 to December 31, 2003 (Reorganized NRG)

Consolidated Statements of Stockholder's (Deficit)/ Equity — Years ended December 31, 2001 and 2002 and for the period January 1, 2003 to December 5, 2003 (Predecessor Company) and the period December 6, 2003 to December 31, 2003 (Reorganized NRG)

Notes to Consolidated Financial Statements

(a)(2) Financial Statement Schedule

The following Consolidated Financial Statement Schedule of NRG Energy is filed as part of Item 15(d) of this report and should be read in conjunction with the Consolidated Financial Statements.

  Report of Independent Registered Public Accounting Firm on Financial Statement Schedule.

Schedule II — Valuation and Qualifying Accounts

All other schedules for which provision is made in the applicable accounting regulation of the Securities and Exchange Commission are not required under the related instructions or are inapplicable, and therefore, have been omitted.

(a)(3) *Exhibits:* See Exhibit Index submitted as a separate section of this report.

(b) *Reports on Form 8-K.* We filed reports on Form 8-K on the following dates over the last fiscal year:

February 21, 2003, March 6, 2003, May 16, 2003, August 27, 2003, October 22, 2003, November 7, 2003, November 19, 2003, December 9, 2003, December 19, 2003, December 24, 2003.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of NRG Energy, Inc.:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of operations, cash flows and stockholders' equity (deficit) present fairly, in all material respects, the financial position of NRG Energy, Inc. and its subsidiaries (Predecessor Company) at December 31, 2002 and the results of their operations and their cash flows for the period from January 1, 2003 to December 5, 2003, and for each of the two years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company filed a petition on May 14, 2003 with the United States Bankruptcy Court for the Southern District of New York for reorganization under the provisions of Chapter 11 of the Bankruptcy Code. NRG Energy, Inc.'s Plan of Reorganization was substantially consummated on December 5, 2003 and Reorganized NRG emerged from bankruptcy. In connection with its emergence from bankruptcy, the Company adopted fresh start accounting.

As discussed in Note 2 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets", as of January 1, 2002. As discussed in Notes 2 and 8 to the consolidated financial statements, the Company adopted Statements of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," on January 1, 2002.

As discussed in Note 6 to the consolidated financial statements, during the first quarter of 2004, PERC and Cobee met the criteria for discontinued operations, during the second quarter of 2004, LSP Energy and Hsin Yu met the criteria for discontinued operations and during the third quarter of 2004, NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC met the criteria for discontinued operations. Accordingly, all periods presented have been restated to present PERC, Cobee, LSP Energy, Hsin Yu and the four NEO Corporation projects as discontinued operations.

As discussed in Note 20 to the consolidated financial statements, the Company revised its segment reporting in 2004 to reflect the realignment of their management team. As a result of these changes, prior period segment disclosures have been recast in a consistent manner.

/s/ PRICEWATERHOUSECOOPERS LLP

PRICEWATERHOUSECOOPERS LLP

Minneapolis, Minnesota

March 10, 2004, except as to Notes 6, 20, 30, and 31, which are as of December 6, 2004

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of NRG Energy, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, cash flows and stockholders' equity present fairly, in all material respects, the financial position of NRG Energy, Inc. and its subsidiaries (Reorganized NRG) at December 6, 2003 and December 31, 2003 and the results of their operations and their cash flows for the period from December 6, 2003 to December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the United States Bankruptcy Court for the Southern District of New York confirmed the NRG Energy, Inc. Plan of Reorganization on November 24, 2003. Confirmation of the plan resulted in the discharge of all claims against the Company that arose before May 14, 2003 and substantially alters rights and interests of equity security holders as provided for in the plan. The NRG Energy, Inc. Plan of Reorganization was substantially consummated on December 5, 2003, and NRG Energy, Inc. emerged from bankruptcy. In connection with its emergence from bankruptcy, NRG Energy, Inc. adopted fresh start accounting as of December 5, 2003.

As discussed in Note 6 to the consolidated financial statements, during the first quarter of 2004, PERC and Cobee met the criteria for discontinued operations, during the second quarter of 2004, LSP Energy and Hsin Yu met the criteria for discontinued operations and during the third quarter of 2004, NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC met the criteria for discontinued operations. Accordingly, all periods presented have been restated to present PERC, Cobee, LSP Energy, Hsin Yu and the four NEO Corporation projects as discontinued operations.

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/S/ PRICEWATERHOUSECOOPERS LLP

PRICEWATERHOUSECOOPERS LLP

Minneapolis, Minnesota

March 10, 2004, except as to Notes 6, 20, 30, and 31, which are as of December 6, 2004

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Predecessor Company			Reorganized NRG
	Year Ended December 31,		January 1, 2003 Through December 5, 2003	December 6, 2003 Through December 31, 2003
	2001	2002		
	(In thousands, except per share amounts)			
Operating Revenues				
Revenues from majority-owned operations	$2,085,350	$ 1,938,293	$ 1,798,387	**$ 138,490**
Operating Costs and Expenses				
Cost of majority-owned operations	1,375,390	1,332,446	1,355,909	**95,541**
Depreciation and amortization	140,976	207,027	218,843	**11,808**
General, administrative and development	187,165	218,852	170,330	**12,518**
Other charges (credits)				
Legal settlement	—	—	462,631	**—**
Fresh start reporting adjustments	—	—	(4,118,636)	**—**
Reorganization items	—	—	197,825	**2,461**
Restructuring and impairment charges	—	2,563,060	237,575	**—**
Total operating costs and expenses	1,703,531	4,321,385	(1,475,523)	**122,328**
Operating Income/(Loss)	381,819	(2,383,092)	3,273,910	**16,162**
Other Income/(Expense)				
Minority interest in earnings of consolidated subsidiaries	—	—	—	**(134)**
Equity in earnings of unconsolidated affiliates	210,032	68,996	170,901	**13,521**
Write downs and losses on sales of equity method investments	—	(200,472)	(147,124)	**—**
Other income, net	22,983	11,431	19,209	**97**
Interest expense	(364,111)	(452,182)	(329,889)	**(18,902)**
Total other expense	(131,096)	(572,227)	(286,903)	**(5,418)**
Income/(Loss) From Continuing Operations Before Income Taxes	250,723	(2,955,319)	2,987,007	**10,744**
Income Tax Expense/(Benefit)	40,221	(166,867)	37,929	**(661)**
Income/(Loss) From Continuing Operations	210,502	(2,788,452)	2,949,078	**11,405**
Income/(Loss) on Discontinued Operations, net of Income Taxes	54,702	(675,830)	(182,633)	**(380)**
Net Income/(Loss)	$ 265,204	$(3,464,282)	$ 2,766,445	**$ 11,025**
Weighted Average Number of Common Shares Outstanding — Basic				**100,000**
Income From Continuing Operations per Weighted Average Common Share — Basic				**$ 0.11**
Loss From Discontinued Operations per Weighted Average Common Share — Basic				**—**
Net Income per Weighted Average Common Share — Basic				**$ 0.11**
Weighted Average Number of Common Shares Outstanding — Diluted				**100,060**
Income From Continuing Operations per Weighted Average Common Share — Diluted				**$ 0.11**
Loss From Discontinued Operations per Weighted Average Common Share — Diluted				**—**
Net Income per Weighted Average Common Shares — Diluted				**$ 0.11**

See notes to consolidated financial statements.

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NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	Predecessor Company	Reorganized NRG	
	December 31, 2002	December 6, 2003	December 31, 2003
		(In thousands)	
ASSETS			
Current Assets			
Cash and cash equivalents	$ 360,860	**$ 395,982**	**$ 551,223**
Restricted cash	211,966	**493,047**	**116,067**
Accounts receivable-trade, less allowance for doubtful accounts of $18,163, $0 and $0	257,620	**213,479**	**201,921**
Xcel Energy settlement receivable	—	**640,000**	**640,000**
Current portion of notes receivable — affiliates	2,442	**—**	**200**
Current portion of notes receivable	52,269	**66,628**	**65,141**
Income tax receivable	8,388	**—**	**—**
Inventory	254,012	**196,236**	**194,926**
Derivative instruments valuation	28,791	**161**	**772**
Prepayments and other current assets	133,635	**210,541**	**222,138**
Current deferred income tax	—	**—**	**1,850**
Current assets — discontinued operations	238,514	**126,576**	**119,601**
Total current assets	1,548,497	**2,342,650**	**2,113,839**
Property, Plant and Equipment			
In service	5,692,019	**3,876,795**	**3,885,465**
Under construction	611,191	**132,003**	**139,171**
Total property, plant and equipment	6,303,210	**4,008,798**	**4,024,636**
Less accumulated depreciation	(501,935)	**—**	**(11,800)**
Net property, plant and equipment	5,801,275	**4,008,798**	**4,012,836**
Other Assets			
Equity investments in affiliates	884,263	**733,862**	**737,998**
Notes receivable, less current portion — affiliates	151,552	**125,651**	**130,152**
Notes receivable, less current portion	784,432	**674,931**	**691,444**
Decommissioning fund investments	4,617	**4,787**	**4,809**
Intangible assets, net of accumulated amortization of $21,618, $0 and $5,212	75,131	**484,668**	**432,361**
Debt issuance costs, net of accumulated amortization of $42,411, $0 and $454	129,160	**—**	**74,337**
Derivative instruments valuation	90,766	**66,442**	**59,907**
Funded letter of credit	—	**—**	**250,000**
Other assets	14,164	**108,744**	**114,131**
Non-current assets — discontinued operations	1,412,994	**616,796**	**623,173**
Total other assets	3,547,079	**2,815,881**	**3,118,312**
Total Assets	$10,896,851	**$9,167,329**	**$9,244,987**

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS — (Continued)

	Predecessor Company	Reorganized NRG	
	December 31, 2002	December 6, 2003	December 31, 2003
		(In thousands)	
LIABILITIES AND STOCKHOLDERS' EQUITY/(DEFICIT)			
Current Liabilities			
Current portion of long-term debt	$ 7,001,134	**$2,496,754**	**$ 801,229**
Revolving line of credit	1,000,000	**—**	**—**
Short-term debt	30,064	**18,645**	**19,019**
Accounts payable — trade	539,996	**202,402**	**158,646**
Accounts payable — affiliates	55,585	**13,365**	**3,092**
Accrued income tax	—	**16,431**	**16,095**
Accrued property, sales and other taxes	24,271	**27,794**	**22,301**
Accrued salaries, benefits and related costs	16,844	**16,718**	**19,330**
Accrued interest	277,116	**75,773**	**8,982**
Derivative instruments valuation	13,439	**95**	**429**
Creditor pool obligation	—	**1,040,000**	**540,000**
Other bankruptcy settlement	—	**220,000**	**220,000**
Other current liabilities	105,341	**136,775**	**102,861**
Current liabilities — discontinued operations	765,621	**112,688**	**114,197**
Total current liabilities	9,829,411	**4,377,440**	**2,026,181**
Other Liabilities			
Long-term debt	781,514	**879,686**	**3,327,782**
Deferred income taxes	74,886	**144,688**	**149,493**
Postretirement and other benefit obligations	67,495	**104,712**	**105,946**
Derivative instruments valuation	91,039	**155,709**	**153,503**
Other long-term obligations	145,594	**536,682**	**480,938**
Non-current liabilities — discontinued operations	602,600	**559,560**	**558,884**
Total non-current liabilities	1,763,128	**2,381,037**	**4,776,546**
Total liabilities	11,592,539	**6,758,477**	**6,802,727**
Minority interest	511	**4,852**	**5,004**
Commitments and Contingencies			
Stockholders' Equity/(Deficit)			
Class A — Common stock; $.01 par value; 100 shares authorized in 2002; 3 shares issued and outstanding at December 31, 2002	—	**—**	**—**
Common stock; $.01 par value; 100 shares authorized in 2002; 1 share issued and outstanding at December 31, 2002	—	**—**	**—**
Common stock; $.01 par value; 500,000,000 shares authorized in 2003; 100,000,000 shares issued and outstanding at December 6, 2003 and December 31, 2003	—	**1,000**	**1,000**
Additional paid-in capital	2,227,692	**2,403,000**	**2,403,429**
Retained earnings/(deficit)	(2,828,933)	**—**	**11,025**
Accumulated other comprehensive income (loss)	(94,958)	**—**	**21,802**
Total stockholders' equity/(deficit)	(696,199)	**2,404,000**	**2,437,256**
Total Liabilities and Stockholders' Equity/(Deficit)	$10,896,851	**$9,167,329**	**$9,244,987**

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Predecessor Company			Reorganized NRG
	Year Ended December 31		January 1, 2003 Through December 5, 2003	December 6, 2003 Through December 31, 2003
	2001	2002		
	(In thousands)			
Cash Flows from Operating Activities				
Net income/(loss)	$ 265,204	$(3,464,282)	$ 2,766,445	**$ 11,025**
Adjustments to reconcile net income/(loss) to net cash provided by operating activities				
Distributions in excess of (less than) equity earnings of unconsolidated affiliates	(119,002)	(22,252)	(41,472)	**2,229**
Depreciation and amortization	212,493	286,623	256,700	**13,041**
Amortization of deferred financing costs	10,668	28,367	17,640	**517**
Amortization of debt discount/(premium)	—	—	—	**1,725**
Write downs and losses on sales of equity method investments	—	196,192	146,938	**—**
Deferred income taxes and investment tax credits	45,556	(230,134)	(1,893)	**(3,262)**
Unrealized (gains)/losses on derivatives	(13,257)	(2,743)	(34,616)	**3,774**
Minority interest	6,564	(19,325)	2,177	**204**
Amortization of out of market power contracts	(54,963)	(89,415)	—	**(13,431)**
Restructuring & impairment charges	—	3,144,509	408,377	**—**
Fresh start reporting adjustments	—	—	(3,895,541)	**—**
Gain on sale of discontinued operations	—	(2,814)	(186,331)	**—**
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions				
Accounts receivable, net	89,523	(15,487)	28,261	**18,030**
Accounts receivable-affiliates	—	2,271	—	**—**
Inventory	(111,131)	42,596	14,128	**11,054**
Prepayments and other current assets	(36,530)	(58,368)	(36,812)	**(9,504)**
Accounts payable	(4,512)	278,900	693,663	**(40,927)**
Accounts payable-affiliates	4,989	47,049	(45,017)	**832**
Accrued income taxes	(75,132)	44,137	21,244	**(1,207)**
Accrued property and sales taxes	4,054	27,481	(3,159)	**(4,590)**
Accrued salaries, benefits, and related costs	15,785	(24,912)	40,690	**3,150**
Accrued interest	35,637	203,234	158,581	**(64,026)**
Other current liabilities	82,754	47,692	(22,797)	**(510,867)**
Other assets and liabilities	(82,686)	10,723	(48,697)	**(6,642)**
Net Cash Provided (Used) by Operating Activities	276,014	430,042	238,509	**(588,875)**
Cash Flows from Investing Activities				
Acquisitions, net of liabilities assumed	(2,813,117)	—	—	**—**
Proceeds from sale of discontinued operations	—	160,791	18,612	**—**
Proceeds from sale of investments	4,063	68,517	107,174	**—**
Proceeds from sale of turbines	—	—	70,717	**—**
(Increase) in trust funds	—	—	(13,971)	**—**
Decrease/(increase) in restricted cash	(99,707)	(197,802)	(252,495)	**375,272**
Decrease/(increase) in notes receivable	45,091	(209,244)	(1,653)	**1,182**
Capital expenditures	(1,322,130)	(1,439,733)	(113,502)	**(10,560)**
Investments in projects	(149,841)	(63,996)	(561)	**(2,522)**
Net Cash Provided (Used) by Investing Activities	(4,335,641)	(1,681,467)	(185,679)	**363,372**
Cash Flows from Financing Activities				
Net borrowings under line of credit agreement	202,000	790,000	—	**—**
Proceeds from issuance of stock	475,464	4,065	—	**—**
Proceeds from issuance of corporate units (warrants)	4,080	—	—	**—**
Proceeds from issuance of short term debt	622,156	—	—	**—**
Capital contributions from parent	—	500,000	—	**—**

Proceeds from issuance of long-term debt	3,268,017	1,086,770	39,988	**2,450,000**
Deferred debt issuance costs	—	—	(18,540)	**(74,795)**
Funded letter of credit	—	—	—	**(250,000)**
Principal payments on long-term debt	(418,171)	(931,505)	(51,392)	**(1,731,932)**
Net Cash Provided (Used) by Financing Activities	4,153,546	1,449,330	(29,944)	**393,273**
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(3,055)	24,950	(22,276)	**(13,562)**
Change in Cash from Discontinued Operations	(40,873)	51,267	34,512	**1,033**
Net Increase in Cash and Cash Equivalents	49,991	274,122	35,122	**155,241**
Cash and Cash Equivalents at Beginning of Period	36,747	86,738	360,860	**395,982**
Cash and Cash Equivalents at End of Period	$ 86,738	$ 360,860	$ 395,982	**$ 551,223**

See notes to consolidated financial statements.

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY/(DEFICIT)

	Class A Common		Common		Additional Paid-In Capital	Retained Earnings/ (Deficit)	Accumulated Other Comprehensive Income/(Loss)	Total Stockholders' Equity/ (Deficit)
	Stock	Shares	Stock	Shares				
					(In thousands)			
Balances at December 31, 2000 (Predecessor Company)	$ 1,476	147,605	$ 324	32,396	$ 1,233,833	$ 370,145	$ (143,690)	$ 1,462,088
Net income						265,204		265,204
Foreign currency translation adjustments and other							(41,600)	(41,600)
Deferred unrealized gains, net on derivatives							71,101	71,101
Comprehensive income for 2001								294,705
Capital stock activity:								
Issuance of corporate units/ warrant					4,080			4,080
Tax benefits of stock option exercise					792			792
Issuance of common stock, net of issuance costs of $23.5 million			185	18,543	475,279			475,464
Balances at December 31, 2001 (Predecessor Company)	$ 1,476	147,605	$ 509	50,939	$ 1,713,984	$ 635,349	$ (114,189)	$ 2,237,129
Net loss						(3,464,282)		(3,464,282)
Foreign currency translation adjustments and other							64,054	64,054
Deferred unrealized loss, net on derivatives							(44,823)	(44,823)
Comprehensive loss for 2002								(3,445,051)
Contribution from parent					502,874			502,874
Issuance of common stock			6	591	8,843			8,849
Impact of exchange offer	(1,476)	(147,605)	(515)	(51,530)	1,991			—
Balances at December 31, 2002 (Predecessor Company)	$ —	—	$ —	—	$ 2,227,692	$(2,828,933)	$ (94,958)	$ (696,199)
Net income						2,766,445		2,766,445
Foreign currency translation adjustments and other							127,754	127,754
Deferred unrealized loss, net on derivatives							(31,363)	(31,363)
Comprehensive income for the period from January 1, 2003 through December 5, 2003								2,862,836
Effects of reorganization					(2,227,692)	62,488	(1,433)	(2,166,637)
Issuance of common stock			1,000	100,000	2,403,000			2,404,000
Balances at December 5, 2003 (Predecessor Company)	$ —	—	$1,000	100,000	$ 2,403,000	$ —	$ —	$ 2,404,000
Net income						**11,025**		**11,025**
Foreign currency translation adjustments and other							**22,325**	**22,325**
Deferred unrealized loss, net on derivatives							**(523)**	**(523)**
Comprehensive income for the period from December 6, 2003 through December 31, 2003								**32,827**
Compensation expense related to stock option plan					**429**			**429**
Balances at December 31, 2003 (Reorganized NRG)	**$ —**	**—**	**$1,000**	**100,000**	**$ 2,403,429**	**$ 11,025**	**$ 21,802**	**$ 2,437,256**

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Organization

General

We are 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.

We were formed in 1992 as the non-regulated subsidiary of Northern States Power, or "NSP", which was itself merged into New Century Energies, Inc. to form Xcel Energy, Inc., or "Xcel Energy" in 2000. While owned by NSP and later by Xcel Energy, we consistently pursued an aggressive high growth strategy focused on power plant acquisitions, high leverage and aggressive development, including site development and turbine orders. In 2002, a number of factors most notably the aggressive prices paid by us for our acquisitions of turbines, development projects and plants, combined with the overall downturn in the power generation industry, triggered a credit rating downgrade (below investment grade), which in turn, precipitated a severe liquidity situation. 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 our plan of reorganization and the plan became effective on December 5, 2003.

As part of the plan of reorganization, Xcel Energy relinquished its ownership interest 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, the "Refinancing Transactions," 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 December 31, 2003, we owned interests in 72 power projects in seven countries having an aggregate generation capacity of approximately 18,200 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 700 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, or "West Coast Power." 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. 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. We also own interests in plants having a generation capacity of approximately 3,000 MW in various international markets, including Australia, Europe and Latin America. Our energy marketing subsidiary, NRG Power Marketing, Inc., or "PMI" began operations in 1998 and is focused on maximizing the value of our North American assets by providing centralized contract origination and 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.

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.

The Bankruptcy Case

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, or "the bankruptcy court." During the bankruptcy proceedings, we continued to conduct our business and manage our properties as debtors in possession pursuant to sections 1107(a) and 1108 of the bankruptcy code. Our subsidiaries that own our international operations, and certain other subsidiaries, were 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 the NRG plan of reorganization, and the plan became effective on December 5, 2003.

Events Leading to the Commencement of the Chapter 11 Filing

Since the 1990's, we pursued a strategy of growth through acquisitions and later the development of new construction projects. This strategy required significant capital, much of which was satisfied primarily with third party debt. Due to a number of reasons, particularly our aggressive pricing of acquisitions and the overall downturn in the power generation industry, our financial condition deteriorated significantly starting in 2001. During 2002, our senior unsecured debt and our project-level secured debt were downgraded multiple times by rating agencies. In September 2002, we failed to make payments due under certain unsecured bond obligations, which resulted in further downgrades.

As a result of the downgrades, the debt load incurred during the course of acquiring assets, declining power prices, increasing fuel prices, the overall downturn in the power generation industry and the overall downturn in the economy, we experienced severe financial difficulties. These difficulties caused us to, among other things, miss scheduled principal and interest payments due to our corporate lenders and bondholders, be required to prepay for fuel and other related delivery and transportation services and be required to provide performance collateral in certain instances. We also recorded asset impairment charges of approximately $3.1 billion during 2002, while we were a wholly-owned subsidiary of Xcel Energy, related to various operating projects as well as for projects that were under construction which we had stopped funding and turbines we had purchased for which we no longer had a use.

In addition, our missed payments resulted in cross-defaults of numerous other non-recourse and limited recourse debt instruments and caused the acceleration of multiple debt instruments, rendering such debt immediately due and payable. In addition, as a result of the downgrades, we received demands under outstanding letters of credit to post collateral aggregating approximately $1.2 billion.

In August 2002, we retained financial and legal restructuring advisors to assist our management in the preparation of a comprehensive financial and operational restructuring. In March 2003, Xcel Energy announced that its board of directors had approved a tentative settlement agreement with us, the holders of most of our long-term notes and the steering committee representing our bank lenders.

We filed two plans of reorganization in connection with our restructuring efforts. The first, filed on May 14, 2003, and referred to as the NRG plan of reorganization, relates to us and the other NRG plan debtors. The second plan, relating to our Northeast and South Central subsidiaries, which we refer to as the Northeast/ South Central plan of reorganization, was filed on September 17, 2003. On November 25, 2003, the bankruptcy court entered an order confirming the Northeast/ South Central plan of reorganization and the plan became effective on December 23, 2003.

On June 6, 2003, LSP-Nelson Energy LLC and NRG Nelson Turbines LLC filed for protection under chapter 11 of the bankruptcy code and on August 19, 2003, NRG McClain LLC filed for protection under chapter 11 of the bankruptcy code. This annual report does not address the plans of reorganization of these subsidiaries because they are not material to our operations and we expect to sell or otherwise dispose of our interest in each subsidiary subsequent to our reorganization.

The following description of the material terms of the NRG plan of reorganization and the Northeast/ South Central plan of reorganization is subject to, and qualified in its entirety by, reference to the detailed provisions of the NRG plan of reorganization and NRG disclosure statement, and the Northeast/ South Central plan of reorganization and Northeast/ South Central disclosure statement, all of which are available for review upon request.

NRG Plan of Reorganization

The NRG plan of reorganization is the result of several months of intense negotiations among us, Xcel Energy and the two principal committees representing our creditor groups, which we refer to as the Global Steering Committee and the Noteholder Committee. A principal component of the NRG 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 the NRG 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.

Under the terms of the Xcel Energy settlement agreement, the Xcel Energy contribution will be or has been paid as follows:

- An initial installment of $238 million in cash was paid on February 20, 2004.

- A second installment of $50 million in cash was paid on February 20, 2004.

- A third installment of $352 million in cash, which Xcel Energy is required to pay on April 30, 2004.

On November 24, 2003, the bankruptcy court issued an order confirming the NRG plan of reorganization, and the plan became effective on December 5, 2003. To consummate the NRG plan of reorganization, we have or will, among other things:

- Satisfy general unsecured claims by:

- issuing new NRG Energy common stock to holders of certain classes of allowed general unsecured claims; and

- making cash payments in the amount of up to $1.04 billion to holders of certain classes of allowed general unsecured claims of which $500 million was paid in December 2003, with proceeds of the Refinancing Transactions;

- Satisfy certain secured claims by either:

- distributing the collateral to the security holder,

- selling the collateral and distributing the proceeds to the security holder or

- other mutually agreeable treatment; and

• Issue to Xcel Energy a $10 million non-amortizing promissory note which will:

• accrue interest at a rate of 3% per annum, and

• mature 2.5 years after the effective date of the NRG plan of reorganization.

Northeast/ South Central Plan of Reorganization

The Northeast/ South Central plan of reorganization was proposed on September 17, 2003 after we secured the necessary financing commitments. 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 settlement further provides that the Northeast/ South Central debtors shall reimburse the informal committee of secured bondholders, the indenture trustee, the collateral agent, and two additional bondholder groups, for any reasonable professional fees, costs or expenses incurred from October 1, 2003 through January 31, 2004 up to a maximum amount of $2.5 million (including in such amount any post-October 1, 2003 fees already reimbursed), with the exception that the parties to the settlement reserved their respective rights with respect to any additional reasonable fees, costs or expenses incurred subsequent to November 25, 2003 related to matters not reasonably contemplated by the implementation of the settlement of the Northeast/ South Central plan of reorganization.

The creditors of Northeast and South Central subsidiaries are unimpaired by the Northeast/ South Central plan of reorganization. This means that holders of allowed general unsecured claims were paid in cash, in full on the effective date of the Northeast/ South Central plan of reorganization. Holders of allowed secured claims will receive or 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.

Note 2 — Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

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 Statement of Position 90-7, *"Financial Reporting by Entities in Reorganization Under the Bankruptcy Code."*

For financial reporting purposes, close of business on December 5, 2003, represents the date of our emergence from bankruptcy. As used herein, the following terms refer to the Company and its operations:

"Predecessor Company"	The Company, pre-emergence from bankruptcy
	The Company's operations, January 1, 2001 – December 5, 2003
"Reorganized NRG"	The Company, post-emergence from bankruptcy
	The Company's operations, December 6, 2003 – December 31, 2003

In January 2003, the FASB issued FASB Interpretation No. 46, *“Consolidation of Variable Interest Entities,”* or “FIN No. 46.” FIN No. 46 requires an enterprise’s consolidated financial statements to include subsidiaries in which the enterprise has a controlling interest. Historically, that requirement has been applied to subsidiaries in which an enterprise has a majority voting interest, but in many circumstances the enterprise’s consolidated financial statements do not include the consolidation of variable interest entities with which it has similar relationships but no majority voting interest. Under FIN No. 46, the voting interest approach is not the approach used to identify the controlling financial interest. The new rule requires that for entities to be consolidated that those assets be initially recorded at their carrying amounts at the date the requirements of the new rule first apply. If determining carrying amounts as required is impractical, then the assets are to be measured at fair value the first date the new rule applies. Any difference between the net amounts of any previously recognized interest in the newly consolidated entity should be recognized as the cumulative effect of an accounting change. In December 2003, the FASB has published a revision to Interpretation 46, or “FIN 46R”, to clarify some of the provisions of FASB Interpretation No. 46, *“Consolidation of Variable Interest Entities,”* and to exempt certain entities from its requirements. As required by SOP 90-7, we have adopted FIN No. 46R as of the adoption of Fresh Start. In connection with the adoption of FIN No. 46R, we have recorded total assets of $54.7 million and total liabilities of $47.5 million as of December 6, 2003 that were previously recorded through equity method investments. The nature of the operations consolidated consisted of hydro power facilities on the East Coast.

The consolidated financial statements include our accounts and operations and those of our subsidiaries in which we have a controlling interest. We account for the operations of LSP-Nelson Energy LLC and NRG Nelson Turbines LLC under the cost method as they are currently in bankruptcy. All significant intercompany transactions and balances have been eliminated in consolidation. Accounting policies for all of our operations are in accordance with accounting principles generally accepted in the United States of America. As discussed in Note 13, we have investments in partnerships, joint ventures and projects. Earnings from equity in international investments are recorded net of foreign income taxes.

Fresh Start Reporting

In accordance with Statement of Position 90-7, *“Financial Reporting by Entities in Reorganization Under the Bankruptcy Code,”* certain companies qualify for fresh start reporting in connection with their emergence from bankruptcy. Fresh start reporting is appropriate on the emergence from chapter 11 if the reorganization value of the assets of the emerging entity immediately before the date of confirmation is less than the total of all post-petition liabilities and allowed claims, and if the holders of existing voting shares immediately before confirmation receive less than 50 percent of the voting shares of the emerging entity. We met these requirements and adopted Fresh Start reporting resulting in the creation of a new reporting entity designated as Reorganized NRG.

The bankruptcy court issued a confirmation order approving our Plan of reorganization on November 24, 2003. Under the requirements of SOP 90-7, the Fresh Start date is determined to be the confirmation date unless significant uncertainties exist regarding the effectiveness of the bankruptcy order. Our Plan of reorganization required completion of the Xcel Energy settlement agreement prior to emergence from bankruptcy. The Xcel Energy settlement agreement was entered into on December 5, 2003. We believe this settlement agreement was a significant contingency and thus delayed the Fresh Start date until the Xcel Energy settlement agreement was finalized on December 5, 2003.

Under the requirements of Fresh Start, we have adjusted our assets and liabilities, other than deferred income taxes, to their estimated fair values as of December 5, 2003. As a result of marking our assets and liabilities to their estimated fair values, we determined that there was a negative reorganization value that was reallocated back to our tangible and intangible assets. Deferred taxes were determined in accordance with SFAS No. 109, *“Accounting for Income Taxes.”* The net effect of all Fresh Start adjustments resulted in a gain of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations), which is reflected in the Predecessor Company's results for the period January 1, 2003 through December 5, 2003. The application of the Fresh Start provisions of SOP 90-7 created a new reporting entity having no retained earnings or accumulated deficit.

As part of the bankruptcy process we engaged an independent financial advisor to assist in the determination of our reorganized enterprise value. The fair value calculation was based on management's forecast of expected cash flows from our core assets. Management's forecast incorporated forward commodity market prices obtained from a third party consulting firm. A discounted cash flow calculation was used to develop the enterprise value of Reorganized NRG, determined in part by calculating the weighted average cost of capital of the Reorganized NRG. The Discounted Cash Flow, or "DCF", valuation methodology equates the value of an asset or business to the present value of expected future economic benefits to be generated by that asset or business. The DCF methodology is a "forward looking" approach that discounts expected future economic benefits by a theoretical or observed discount rate. The independent financial advisor prepared a 30-year cash flow forecast using a discount rate of approximately 11%. The resulting reorganization enterprise value as included in the Disclosure Statement ranged from $5.5 billion to $5.7 billion. The independent financial advisor then subtracted our project level debt and made several other adjustments to reflect the values of assets held for sale, excess cash and collateral requirements to estimate a range of Reorganized NRG equity value of between $2.2 billion and $2.6 billion.

In constructing our Fresh Start balance sheet upon our emergence from bankruptcy, we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Our NRG Plan of reorganization provided for the issuance of 100,000,000 shares of NRG common stock to the various creditors resulting in a calculated price per share of $24.04. Our reorganization value of approximately $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. The reorganization value represents the fair value of an entity before liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after restructuring. This value is consistent with the voting creditors and Court's approval of the Plan of Reorganization.

Our Fresh Start adjustments consist primarily of the valuation of our existing fixed assets and liabilities, equity investments and recognition of the value of certain power sales contracts that were deemed to be significantly valuable or burdensome as either intangible assets or liabilities which will be amortized into income over the respective terms of each contract. A description of the adjustments and amounts is provided in Note 3 — Emergence from Bankruptcy and Fresh Start Reporting.

A separate plan of reorganization was filed for our Northeast Generating and South Central Generating entities that was confirmed by the bankruptcy court on November 25, 2003, and became effective on December 23, 2003, when the final conditions of the plan were completed. In connection with Fresh Start on December 5, 2003, we continued to consolidate our Northeast Generating and South Central Generating entities, as we believe that we continued to maintain control over the Northeast Generating and South Central Generating facilities through out the bankruptcy process. As previously stated, the Northeast Generating and South Central Generating entities emerged from bankruptcy on December 23, 2003. However, since the creditors received full recovery, the liabilities are not recorded as subject to compromise in the December 6, 2003 balance sheet.

Due to the adoption of the Fresh Start upon our emergence from bankruptcy, the Reorganized NRG 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 therefore not comparable to the financial statements prior to the application of Fresh Start.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Nature of Operations

We are 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, which help us, mitigate risk. 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.

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments (primarily commercial paper) with an original maturity of three months or less at the time of purchase.

Restricted Cash

Restricted cash consists primarily of funds held to satisfy the requirements of certain debt agreements and funds held within our projects that are restricted in their use.

Inventory

Inventory is valued at the lower of weighted average cost or market and consists principally of fuel oil, spare parts, coal, kerosene, emission allowance credits and raw materials used to generate steam.

Property, Plant and Equipment

Property, plant and equipment are stated at cost however impairment adjustments are recorded whenever events or changes in circumstances indicate carrying values may not be recoverable. On December 5, 2003, we recorded adjustments to the property, plant and equipment to reflect such items at fair value in accordance with Fresh Start reporting. A new cost basis was established with these adjustments. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred. Depreciation is computed using the straight-line method over the following estimated useful lives:

Facilities and equipment	10-60 years
Office furnishings and equipment	3-15 years

The assets and related accumulated depreciation amounts are adjusted for asset retirements and disposals with the resulting gain or loss included in operations.

Asset Impairments

Long-lived assets that are held and used are reviewed for impairment whenever events or changes in circumstances indicate carrying values may not be recoverable. Such reviews are performed in accordance with SFAS No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Asset."* An impairment loss is recognized if the total future estimated undiscounted cash flows expected from an asset are less than its carrying value. An impairment charge is measured by the difference between an asset's carrying amount and fair value. Fair values are determined by a variety of valuation methods, including appraisals, sales prices of similar assets and present value techniques.

Investments accounted for by the equity method are reviewed for impairment in accordance with APB Opinion No. 18, *"The Equity Method of Accounting for Investments in Common Stock."* APB Opinion No. 18 requires that a loss in value of an investment that is other than a temporary decline should be recognized. We identify and measure losses in value of equity investments based upon a comparison of fair value to carrying value.

Discontinued Operations

Long-lived assets are classified as discontinued operations when all of the required criteria specified in SFAS No. 144 are met. These criteria include, among others, existence of a qualified plan to dispose of an asset, an assessment that completion of a sale within one year is probable and approval of the appropriate level of management and board of directors. Discontinued operations are reported at the lower of the asset's carrying amount or fair value less cost to sell.

Capitalized Interest

Interest incurred on funds borrowed to finance projects expected to require more than three months to complete is capitalized. Capitalization of interest is discontinued when the asset under construction is ready for its intended use or when a project is terminated or construction ceased. Capitalized interest was approximately $27.2 million, $64.8 million, $15.9 thousand and $1.5 thousand in 2001, 2002, 2003 Predecessor Company and 2003 Reorganized NRG, respectively.

Capitalized Project Costs

Development costs and capitalized project costs include third party professional services, permits, and other costs that are incurred incidental to a particular project. Such costs are expensed as incurred until an acquisition agreement or letter of intent is signed, and our Board of Directors has approved the project. Additional costs incurred after this point are capitalized. When a project begins operation, previously capitalized project costs are reclassified to equity investments in affiliates or property, plant and equipment and amortized on a straight-line basis over the lesser of the life of the project's related assets or revenue contract period. Capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

Debt Issuance Costs

Debt issuance costs are capitalized and amortized as interest expense on a basis, which approximates the effective interest method over the terms of the related debt.

Goodwill and Intangible Assets

Goodwill represents the excess of the purchase price of net tangible and intangible assets acquired in business combinations over their estimated fair value. Effective January 1, 2002, we implemented SFAS No. 142, *"Goodwill and Other Intangible Assets"* or "SFAS No. 142." Pursuant to SFAS No. 142, goodwill is not amortized but is subject to periodic impairment testing. Prior to 2002, goodwill was amortized on a straight-line basis over 20 to 30 years.

Intangible assets represent contractual rights held by us. Intangible assets are amortized over their economic useful life and reviewed for impairment on a periodic basis. Non-amortized intangible assets, including goodwill, are tested for impairment annually and on an interim basis if an event or circumstance occurs between annual tests that might reduce the fair value of that asset.

Income Taxes

The Predecessor Company's income tax provision for the period January 1, 2003 through December 5, 2003 has been recorded on the basis that separate federal income tax returns will be filed. The Reorganized NRG's income tax provision for the period December 6, 2003 through December 31, 2003 has been recorded on the basis that we and our U.S. subsidiaries will reconsolidate for federal income tax purposes as of December 6, 2003. The income tax provision for the year ended December 31, 2002 has been recorded on the basis that we and our U.S. subsidiaries have filed a consolidated federal income tax return for the period January 1, 2002 through June 3, 2002 and filed separate federal income tax returns for the remainder of 2002.

The Predecessor Company's income taxes have been recorded on the basis that Xcel Energy has not included us in its consolidated federal income tax return following Xcel Energy's acquisition of our public shares on June 3, 2002. Since we and our U.S. subsidiaries will not be included in the Xcel Energy consolidated tax group, each of our U.S. subsidiaries that is classified as a corporation for U.S. income tax purposes must file a separate federal income tax return for the periods ended December 31, 2002 and December 5, 2003.

The Reorganized NRG is no longer owned by Xcel Energy and thus, no longer included in the Xcel Energy affiliated group. The change in ownership allows us to file a consolidated federal income tax return with our U.S. subsidiaries starting on December 6, 2003.

Deferred income taxes are recognized for the tax consequences in future years of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts at each year-end based on enacted tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. Income tax expense is the tax payable for the period and the change during the period in deferred tax assets and liabilities. A valuation allowance is recorded to reduce deferred tax assets to the amount more likely than not to be realized.

Revenue Recognition

We are primarily an electric generation company, operating a portfolio of majority-owned electric generating plants and certain plants in which our ownership interest is 50% or less and which are accounted for under the equity method. In connection with our electric generation business, we also produce thermal energy for sale to customers, principally through steam and chilled water facilities. We also collect methane gas from landfill sites, which are used for the generation of electricity. In addition, we sell small amounts of natural gas and oil to third parties.

Electrical energy revenue is recognized upon delivery to the customer. In certain markets, which are operated/controlled by an independent system operator and in which we have entered into a netting agreement with the ISO, which results in our receiving a netted invoice, we have recorded purchased energy as an offset against revenues received upon the sale of such energy. Capacity and ancillary revenue is recognized when contractually earned. Disputed revenues are not recorded in the financial statements until disputes are resolved and collection is assured.

Revenue from long-term power sales contracts that provide for higher pricing in the early years of the contract are recognized in accordance with Emerging Issues Task Force Issue No. 91-6, *"Revenue Recognition of Long Term Power Sales Contracts."* This results in revenue deferrals and recognition on a levelized basis over the term of the contract.

We provide contract operations and maintenance services to some of our non-consolidated affiliates. Revenue is recognized as contract services are performed.

We recognize other income for interest income on loans to our non-consolidated affiliates, as the interest is earned and realizable.

Foreign Currency Translation and Transaction Gains and Losses

The local currencies are generally the functional currency of our foreign operations. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses and cash flows are translated at weighted-average rates of exchange for the period. The resulting currency translation adjustments are accumulated and reported as a separate component of stockholders' equity and are not included in the determination of the results of operations. Foreign currency transaction gains or losses are reported in results of operations. We recognized foreign currency transaction gains (losses) of $1.8 million, $(10.4) million, $(19.8) million and $0.4 million in 2001, 2002, 2003 Predecessor Company and 2003 Reorganized NRG, respectively.

Concentrations of Credit Risk

Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of cash, accounts receivable, notes receivable and investments in debt securities. Cash accounts are generally held in Federally insured banks. Accounts receivable, notes receivable and derivative instruments are concentrated within entities engaged in the energy industry. These industry concentrations may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. Receivables are generally not collateralized; however, we believe the credit risk posed by industry concentration is offset by the diversification and creditworthiness of our customer base.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, receivables, accounts payables, and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying amounts of long-term receivables approximate fair value, as the effective rates for these instruments are comparable to market rates at year-end, including current portions. The fair value of long-term debt is estimated based on quoted market prices for those instruments which are traded or on a present value method using current interest rates for similar instruments with equivalent credit quality.

Pensions

The determination of our obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets and the rate of future compensation increases. Our actuarial consultants use assumptions for such items as retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of pension obligation or expense recorded by us.

Stock Based Compensation

During the fourth quarter of 2003, in accordance with SFAS Statement No. 148, *"Accounting for Stock-Based Compensation — Transition and Disclosure"* we adopted SFAS No. 123 under the prospective transition method which requires the application of the recognition provisions to all employee awards granted, modified, or settled after the beginning of the fiscal year in which the recognition provisions are first applied. As a result, we applied the fair value recognition provisions of SFAS No. 123 as of January 1, 2003. As discussed in Note 18, we recognized compensation expense for the grants issued under the Long-Term Incentive Plan.

Net Income Per Share

Basic net income per share is calculated based on the weighted average of common shares outstanding during the period. Net income per share, assuming dilution is computed by dividing net income by the weighted average number of common and common equivalent shares outstanding. Our only common equivalent shares are those that result from dilutive common stock options and restricted stock.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

In recording transactions and balances resulting from business operations, we use estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, un- collectible accounts, actuarially determined benefit costs and the valuation of long-term energy commodities contracts, among others. In addition, estimates are used to test long-lived assets for impairment and to determine fair value of impaired assets. As better information becomes available (or actual amounts are determinable), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Reclassifications

Certain prior-year amounts have been reclassified for comparative purposes. These reclassifications had no effect on our net income or total stockholders' equity as previously reported.

Recent Accounting Developments

As part of the provisions of SOP 90-7, we are required to adopt, for the current reporting period, all accounting guidance that is effective within a twelve-month period. As a result, we have adopted all provisions of FASB Interpretation No. 46R, *"Consolidation of Variable Interest Entities".*

Note 3 — Emergence from Bankruptcy and Fresh Start Reporting

In accordance with the requirements of SOP 90-7, we determined the reorganization value of NRG and subsidiaries emerging from bankruptcy to be approximately $9.1 billion. Reorganization value generally approximates fair value of the entity before considering liabilities and approximates the amount a willing buyer would pay for the assets of the entity immediately after the restructuring. Several methods are used to determine the reorganization value; however, generally it is determined by discounting future cash flows for the reconstituted business that will emerge from chapter 11 bankruptcy. Our approach was consistent in that our independent financial advisor's estimated reorganization enterprise value of our ongoing projects using a discounted cash flow approach.

We allocated the reorganization value of $9.1 billion to our assets in conformity with the procedures specified by SFAS No. 141. We used a third party to complete an independent appraisal of our tangible assets, equity investments and intangible assets and contracts. In completing the fair value allocation our assets were calculated to be greater than the reorganization value. As a result, we reallocated the negative reorganization value to our tangible and intangible assets in accordance with SFAS No. 141. In preparing our balance sheet we also recorded each liability existing at the plan confirmation date, other than deferred taxes, at the present value of amounts to be paid determined at appropriate current interest rates. Deferred taxes were reported in conformity with generally accepted accounting principles under SFAS No. 109. Our equity was recorded at approximately $2.4 billion representing a price per share of $24.04 for the issuance of 100,000,000 shares of common stock with bankruptcy emergence. We pushed down the effects of fresh start reporting to all of our subsidiaries.

In constructing our Fresh Start balance sheet using our reorganization value upon our emergence from bankruptcy we used a reorganization equity value of approximately $2.4 billion, as we believe this value to be the best indication of the value of the ownership distributed to the new equity owners. Accordingly, our reorganization value of $9.1 billion was determined by adding our reorganized equity value of $2.4 billion, $3.7 billion of interest bearing debt and our other liabilities of $3.0 billion. This value is consistent with the voting creditors and Court's approval of the Plan of Reorganization.

The determination of the enterprise value and the allocations to the underlying assets and liabilities were based on a number of estimates and assumptions, which are inherently subject to significant uncertainties and contingencies.

We recorded approximately $3.9 billion of net reorganization income (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations) in the Predecessor Company's statement of operations for 2003, which includes the gain on the restructuring of debt and equity and the discharge of obligations subject to compromise for less than recorded amounts, as well as adjustments to the historical carrying values of our assets and liabilities to fair market value.

Due to the adoption of Fresh Start as of December 5, 2003, the Reorganized NRG 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 and the Predecessor Company. The effects of the reorganization and Fresh Start on our balance sheet as of December 5, 2003, were as follows (in thousands):

	Predecessor Company December 5, 2003	Debt Discharge and Exchange of Stock	Fresh Start Adjustments		Consolidation	Reorganized NRG December 6, 2003
Current Assets						
Cash and cash equivalents	$ 396,018	$ (1,728)(B)	$	$	$ 1,692 (T)	$ 395,982
Restricted cash	489,383	1,732 (B)			1,932 (T)	493,047
Accounts receivable — trade, net	208,677		(2)(B)	3,627 (J)	1,177 (T)	213,479
Accounts receivable — affiliates	41,259		819 (B)	(42,078)(J)		—
Xcel Energy settlement receivable		640,000 (A)				640,000
Current portion of notes receivable	66,628					66,628
Inventory	233,185		(25,945)(K)	(11,004)(L)		196,236
Derivative instruments valuation	161					161
Prepayments and other current assets	156,785	(25,855)(B)	(7,309)(M)	85,873 (J)	1,047 (T)	210,541
Current assets — discontinued operations	126,188		(1,241)(K)	1,629 (J)		126,576
Total current assets	1,718,284	614,149	(33,678)	38,047	5,848	2,342,650
Property, Plant and Equipment						
Net property, plant and equipment	5,247,375		(1,153,101)(I)	(132,128)(J)	46,652 (T)	4,008,798

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Predecessor Company December 5, 2003	Debt Discharge and Exchange of Stock	Fresh Start Adjustments		Consolidation	Reorganized NRG December 6, 2003
Other Assets						
Equity investments in affiliates	956,757		(216,029)(C)	14 (J)	(6,880)(T)	733,862
Notes receivable, less current portion — affiliates	164,987		(39,336)(P)			125,651
Notes receivable, less current portion	752,847	(155,477)(D)	77,862 (P)		(301)(T)	674,931
Decommissioning fund investments	4,787					4,787
Intangible assets, net	70,275		437,222 (O)	(22,829)(I)		484,668
Debt issuance costs, net	67,045		(67,045)(P)			—
Derivative instruments valuation	66,442					66,442
Other assets	14,122		(37,891)(P)	98,857 (J)	2,170 (T)	108,744
				31,486 (J)		
Non-current assets — discontinued operations	826,715		(209,919)(P)			616,796
Total other assets	2,923,977	(155,477)	(55,136)	107,528	(5,011)	2,815,881
Total Assets	$ 9,889,636	$ 458,672	$(1,241,915)	$ 13,447	$ 47,489	$ 9,167,329
Current Liabilities						
Current portion of long-term debt	$ 1,433,551	$ (155,477)(D)	$ (89,182)(P)	$ 1,307,249 (Q)	$ 613 (T)	$ 2,496,754
Short-term debt			18,645 (P)			18,645
Accounts payable — trade	299,340	(101,632)(E)	(805)(N)	5,499 (J)		202,402
Accounts payable — affiliates	17,834	(2,308)(B)	(5,192)(N)	2,995 (J)	36 (T)	13,365
Accrued income tax	19,303		(7,127)(M)	4,255 (J)		16,431
Accrued property, sales and other taxes	30,180		(5,942)(B)	3,556 (J)		27,794
Accrued salaries, benefits and related costs	14,194			2,519 (J)	5 (T)	16,718
Accrued interest	76,485	(2,464)(B)		1,631 (J)	121 (T)	75,773
Derivative instruments valuation	95					95
Creditor pool obligation		1,040,000 (F)				1,040,000
Other bankruptcy settlement		220,000 (F)				220,000
Other current liabilities	135,274	57 (F)	11,800 (O)	(10,770)(J)	413 (T)	136,774
Current liabilities — discontinued operations	164,362		(51,679)(J)	6 (J)		112,689
Total current liabilities	2,190,618	998,176	(129,482)	1,316,940	1,188	4,377,440
Other Liabilities						
Long-term debt	849,192	10,000 (G)	(21,869)(P)	303 (J)	42,060 (T)	879,686
Deferred income taxes	146,120		(13,973)(M)	12,541 (J)		144,688
Postretirement and other benefit obligations	44,601	(1,118)(B)	64,067 (R)	(2,838)(J)		104,712
Derivative instruments valuation	53,082			102,627 (J)		155,709
Other long-term obligations	146,761	763 (B)	488,218 (O)	(99,060)(J)		536,682
Non-current liabilities — discontinued operations	558,194		1,366 (M)			559,560
Total non-current liabilities	1,797,950	9,645	517,809	13,573	42,060	2,381,037
Total liabilities not subject to compromise	3,988,568	1,007,821	388,327	1,330,513	43,248	6,758,477
Total liabilities subject to compromise	7,658,071	(6,278,547)(H)	(1,367)(J)	(1,378,157)(Q)		—
Total liabilities	11,646,639	(5,270,726)	386,960	(47,644)	43,248	6,758,477
Minority interest	611				4,241 (T)	4,852

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Predecessor Company December 5, 2003	Debt Discharge and Exchange of Stock	Fresh Start Adjustments		Consolidation	Reorganized NRG December 6, 2003
Commitments and Contingencies						
Stockholders' Equity/ Deficit						
Class A — Common stock; $.01 par value; 100 shares authorized in 2002; 3 shares issued and outstanding at December 31, 2002	1	(1)(S)				—
Common stock; $.01 par value; 100 authorized in 2002; 1 share issued and outstanding at December 31, 2002	—					—
Common stock; $.01 par value; 500,000,000 authorized in 2003; 100,000,000 shares issued and outstanding at December 6, 2003	—	1,000 (H)				1,000
Additional paid-in capital	2,227,691	2,403,000 (H)	(2,227,691)(S)			2,403,000
Retained earnings/deficit	(3,986,739)		3,924,215 (S)	62,524 (S)		—
Accumulated other comprehensive income (loss)	1,433			(1,433)(S)		—
Total stockholders' equity/(deficit)	(1,757,614)	2,403,999	1,696,524	61,091	—	2,404,000
Total Liabilities and Stockholders' Equity/ Deficit	$ 9,889,636	$ (2,866,727)	$ 2,083,484	$13,447	$ 47,489	$ 9,167,329

(A) Represents a $640.0 million receivable from Xcel Energy that relates to the Xcel Energy Settlement Agreement. $288.0 million was paid on February 20, 2004 in cash and $352.0 million will be paid on April 30, 2004.

(B) Adjustments to assets and liabilities resulting from the NRG Energy bankruptcy settlement.

(C) Includes the adjustment of carrying amount of Investments in Projects to fair market value as determined by independent appraisers.

(D) The NRG Energy bankruptcy settlement included the liquidation of NRG FinCo. As a result, the NRG FinCo creditors obtained a perfected first priority security interest in all of LSP Pike Energy LLC assets, making the Mississippi Industrial Revenue Bonds owed by LSP Pike Energy LLC worthless.

(E) Includes $103.0 million discharge of obligations related to LSP Pike Energy LLC settlement with Shaw Constructors, Inc.

(F) Includes the establishment of a creditor's pool and the FinCo lender settlement:

Creditor installment payments	$ 515.0
Establishment of plan of reorganization liability	500.0
Contingency payment	25.0
FinCo lender settlement (see note 24)	220.0
Total other current liabilities	$1,260.0

(G) Represents NRG Energy Promissory Note owed to Xcel Energy, due June 5, 2006 with a stated interest rate of 3.0%

(H) Represents the elimination of approximately $5.2 billion of corporate level bank and bond debt and approximately $1.1 billion of additional claims and disputes by distributing a combination of equity and up to $1.04 billion in cash among our unsecured creditors. Upon reorganization we issued 100 million shares of NRG common stock at $24.04 per share.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(I) Result of allocating the reorganization value in conformity with the purchase method of accounting for business combinations. These allocations were based on valuations obtained from independent appraisers.

(J) Adoption of Fresh Start Reporting and reinstatement of miscellaneous liabilities subject to compromise.

(K) Accounting policy change upon adoption of fresh start reporting. Consumables are no longer included as inventory and are expensed as incurred.

(L) Accounting policy change upon adoption of fresh start reporting. Capital spares were reclassified from inventory to Property Plant and Equipment.

(M) Records income taxes of the Company based on the guidance provided in the Statement of Financial Accounting Standards No. 109 and SOP 90-7.

(N) Adjust assets and liabilities to reflect management’s estimate, with the assistance of independent specialists, of the fair value.

(O) Reflects management’s estimate, with the assistance of independent appraisers, of the fair value of power purchase agreements and SO(2) emission credits. Management identified certain power purchase agreements that were either significantly valuable or significantly burdensome as compared to our market expectations. The predecessor goodwill and intangibles were written off. Our guarantees were reviewed for the requirement to recognize a liability at inception. As a result, we recorded a $15.0 million liability. In addition, our Asset Retirement Obligation or “ARO” was revalued.

SO(2) emission credits	$373.5
Valuable contracts	111.2
Predecessor intangible	(47.5)
Total Intangible	$437.2
Burdensome contracts	$ 15.1
Other valuations adjustments	(3.3)
Total other current liabilities	$ 11.8
Burdensome contracts	$467.2
Other valuations adjustments	21.0
Total other long-term obligations	$488.2

(P) Reflects management’s estimate, based on current market interest rates as of December 5, 2003, of the fair value of notes receivable, notes payable and other debt instruments.

(Q) Reclassification of subject to compromise liabilities due to emergence from bankruptcy consists primarily of the debt held at our Northeast and South Central subsidiaries of $1.3 billion. The remaining amounts were reclassified to current liabilities.

(R) Adjustment to post-retirement and other benefit obligations in order to reflect the accumulated benefit obligation liability based on independent actuarial reports. The pension and welfare plans were assumed from Xcel Energy without the transfer of assets.

(S) Reflects the cancellation of the Predecessor Company’s common stock and the elimination of the retained deficit and the accumulated other comprehensive loss.

(T) As required by SOP 90-7, we have adopted FASB Interpretation No. 46 “Consolidation of Variable Interest Entities,” or “FIN 46,” as of the adoption of Fresh Start. The adoption of FIN 46 resulted in the consolidation of Northbrook New York, LLC and Northbrook Energy, LLC.

APB No. 18, *“The Equity Method of Accounting for Investments in Common Stock”,* requires us to effectively push down the effects of Fresh Start reporting to our unconsolidated equity method investments and to recognize an adjustment to our share of the earnings or losses of an investee as if the investee was a consolidated subsidiary. As a result of pushing down the impact of Fresh Start to our West Coast Power affiliate we determined that a contract based intangible asset with a one year remaining life, consisting of the value of West Coast Power's California Department of Water Resources energy sales contract, must be established and recognized as a basis adjustment to our share of the future earnings generated by West Coast Power. This adjustment will reduce our equity earnings in the amount of approximately $10.4 million per month during 2004 until the contract expires in December 2004.

Note 4 — Financial Instruments

The estimated fair values of our recorded financial instruments are as follows:

	Predecessor Company		Reorganized NRG			
	December 31, 2002		December 6, 2003		December 31, 2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)					
Cash and cash equivalents	$ 360,860	$ 360,860	**$ 395,982**	**$ 395,982**	**$ 551,223**	**$ 551,223**
Restricted cash	211,966	211,966	**493,047**	**493,047**	**116,067**	**116,067**
Notes receivable, including current portion	990,695	990,695	**867,210**	**867,210**	**886,937**	**886,937**
Long-term debt, including current portion	7,782,648	5,491,081	**3,376,440**	**3,376,440**	**4,129,011**	**4,186,136**

For cash and cash equivalents and restricted cash, the carrying amount approximates fair value because of the short-term maturity of those instruments. The fair value of notes receivable is based on expected future cash flows discounted at market interest rates. The fair value of long-term debt is estimated based on quoted market prices for those instruments which are traded or on a present value method using current interest rates for similar instruments with equivalent credit quality.

Note 5 — Debtors' Statements

As stated above, we and certain of our subsidiaries filed voluntary petitions for reorganization under chapter 11 of the Bankruptcy Code during 2003. On December 5, 2003, we and five of our subsidiaries emerged from bankruptcy. As of the respective bankruptcy filing dates, the Debtors' financial records were closed for the Prepetition Period. As required by SOP 90-7 *"Financial Reporting by Entities in Reorganization Under the Bankruptcy Code"*, below are the condensed combined financial statements of our remaining Debtors since the date of the bankruptcy filings, "the Debtors' Statements."

The Debtors' Statements consist of the following wholly-owned consolidated entities which remained in bankruptcy as of December 6, 2003: Arthur Kill Power LLC, Astoria Gas Turbine Power LLC, Berrians I Gas Turbine Power, LLC, Big Cajun II Unit 4 LLC, Connecticut Jet Power LLC, Devon Power LLC, Dunkirk Power LLC, Huntley Power LLC, Louisiana Generating LLC, LSP-Nelson Energy LLC, Middletown Power LLC, Montville Power LLC, Northeast Generation Holding LLC, Norwalk Power LLC, NRG Central US LLC, NRG Eastern LLC, NRG McClain LLC, NRG Nelson Energy LLC, NRG New Roads Holdings LLC, NRG Northeast Generating LLC, NRG South Central Generating LLC, Oswego Harbor Power LLC, Somerset Power LLC, and South Central Generation Holding LLC. As of December 31, 2003, three entities remain in bankruptcy. Two entities have been deconsolidated and accounted for under the cost method because we have effectively lost control of those entities including NRG Nelson Turbine, LLC and LSP-Nelson Energy LLC. The other entity, NRG McClain LLC, is shown as a discontinued operation since it was held for sale prior to filing for bankruptcy.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Debtors' Condensed Combined Statement of Operations

	For the Period May 15, 2003 – December 5, 2003
	(In thousands)
Operating revenue	$ 731,413
Operating costs and expenses	620,199
Fresh start reporting adjustments — asset write-downs, net	1,244,016
Reorganization items	27,158
Restructuring and impairment charges	23,359
Operating loss	(1,183,319)
Other expense	(160,246)
Net loss	$(1,343,565)

Debtors' Condensed Combined Balance Sheet

	December 6, 2003
	(In thousands)
ASSETS	
Cash	$ 16,421
Accounts receivables-trade	38,018
Accounts receivables, non-Debtor affiliates	31,019
Inventory	150,618
Current portion of notes receivable	1,500
Other current assets	183,433
Total current assets	421,009
Property, plant and equipment, net	1,829,118
Investment in non-Debtors	573
Intangible assets, net	335,851
Other assets	191,257
Total assets	$2,777,808
LIABILITIES AND STOCKHOLDERS' EQUITY	
Accounts payable-trade	$ 18,809
Debt Obligation	1,307,250
Other current liabilities	74,143
Total current liabilities	1,400,202
Other long-term obligations	715,454
Total stockholders' equity	662,152
Total liabilities and stockholders' equity	$2,777,808

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Debtors' Condensed Combined Statement of Cash Flows

	For the Period May 15, 2003 – December 5, 2003
	(In thousands)
Net cash provided by operating activities	$ 65,951
Net cash used by investing activities	(72,667)
Net cash used by financing activities	—
Net increase in cash and cash equivalents	(6,716)
Cash and cash equivalents at beginning of period	23,137
Cash and cash equivalents at end of period	$ 16,421

Note 6 — Discontinued Operations

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 our management considered cash flow analyses, bids and offers related to those assets and businesses. This amount is included in income/(loss) on discontinued operations, net of income taxes in the accompanying Statement 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.

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.

Summarized results of operations of the discontinued operations were as follows. For the years ended December 31, 2001 and December 31, 2002, discontinued results of operations included our Crockett Cogeneration, Bulo Bulo, Csepel, Entrade, Killingholme, NLGI, McClain, TERI, NEO Corporation projects, Cahua, Energia Pacasmayo, PERC, Cobee, LSP Energy and Hsin Yu. For the period from January 1, 2003 to December 5, 2003, discontinued results of operations include our Killingholme, McClain, NLGI, NEO Corporation projects, TERI, Cahua, Energia Pacasmayo, PERC, Cobee, LSP Energy and Hsin Yu projects. For the period December 6, 2003 to December 31, 2003, discontinued results of operations include our McClain, PERC, Cobee, LSP Energy and Hsin Yu projects. During the first quarter 2004 we determined that PERC and Cobee met the criteria for discontinued operations, accordingly all periods presented have been restated. During the second quarter 2004 we determined that LSP Energy and Hsin Yu met the criteria for discontinued operations, accordingly all periods presented have been restated. During the third quarter of 2004 we determined that NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO

Table of Contents

Tajiguas LLC met the criteria for discontinued operations, accordingly all periods presented have been restated.

Description	Predecessor Company Year Ended December 31, 2001	Predecessor Company Year Ended December 31, 2002	Reorganized NRG For the Period January 1 – December 5, 2003	Reorganized NRG For the Period December 6 – December 31, 2003
		(In thousands)		
Operating revenues	$713,258	$ 982,263	$ 263,404	**$ 19,195**
Operating and other expenses	665,372	1,670,709	619,714	**19,565**
Pre-tax income/(loss) from operations of discontinued components	47,886	(688,446)	(356,310)	**(370)**
Income tax expense/(benefit)	(6,816)	(6,810)	(21,868)	**10**
Income/(loss) from operations of discontinued components	54,702	(681,636)	(334,442)	**(380)**
Disposal of discontinued components — pre-tax gain (net)	—	2,814	151,809	**—**
Income tax benefit	—	(2,992)	—	**—**
Disposal of discontinued components — gain (net)	—	5,806	151,809	**—**
Net income/(loss) on discontinued operations	$ 54,702	$ (675,830)	$ (182,633)	**$ (380)**

Operating and other expenses for 2001 and 2002 shown in the table above included asset impairment charges of $0 and approximately $502.0 million, respectively. The 2002 charges are comprised of approximately $477.9 million for the Killingholme project, $121.9 million for the Hsin Yu project, $64.7 million for the Batesville turbine project, $12.4 million for the NEO Landfill Gas, Inc. project and $11.7 million for the TERI project. Operating and other expenses for 2003 include asset impairment charges of approximately $124.3 million, comprised of approximately $100.7 million for McClain and $23.6 million for NLGI.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The components of income tax benefit attributable to discontinued operations were as follows:

	Predecessor Company			Reorganized NRG
	Year Ended December 31,		For the Period January 1 – December 5,	For the Period December 6 – December 31,
Discontinued Operations:	2001	2002	2003	2003
		(In thousands)		
Current				
U.S.	$ 509	$ 935	$ (6)	$ —
Foreign	(2,876)	(5,126)	(831)	10
	(2,367)	(4,191)	(837)	10
Deferred				
U.S.	(45)	(1,947)	—	—
Foreign	9,439	(672)	(21,031)	—
	9,394	(2,619)	(21,031)	—
Section 29 tax credits	(13,843)	—	—	—
	(6,816)	(6,810)	(21,868)	10
Disposal of discontinued components — gain (net)				
U.S.	—	(2,992)	—	—
Foreign	—	—	—	—
	—	(2,992)	—	—
Total income tax expense/(benefit)	$ (6,816)	$(9,802)	$ (21,868)	$ 10

The assets and liabilities of the discontinued operations are reported in the December 31, 2003, December 6, 2003 and December 31, 2002 balance sheets as discontinued operations. The major classes of assets and liabilities are presented by geographic area in the following table. As of December 6, 2003 and December 31, 2003, within our Wholesale Power Generation — Other North America segment, the PERC, McClain and LSP Energy projects are included, the Cobee and Hsin Yu projects are included in the All Other Wholesale Power Generation Other International category and the NEO Corporation projects are included in the All Other Alternative Energy category. As of December 31, 2002, within our Wholesale Power Generation Other North America segment, the PERC, McClain and LSP Energy projects are included, the Killingholme, Cahua, Pacasmayo, Cobee and Hsin Yu projects are included in the All Other Wholesale Power Generation

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Other International category and the NEO Corporation and TERI projects are included in the All Other Alternative Energy category.

	Reorganized NRG							
	December 6, 2003				December 31, 2003			
	Wholesale Power Generation	All Other			Wholesale Power Generation	All Other		
		Wholesale Power Generation				Wholesale Power Generation		
	Other North America	Other International	Alternative Energy	Total	Other North America	Other International	Alternative Energy	Total
	(In thousands)							
Cash and cash equivalents	$ 4,994	$ 8,597	$ —	$ 13,591	$ 4,292	$ 8,264	$ —	$ 12,556
Restricted cash	56,848	—	—	56,848	60,292	—	—	60,292
Receivables, net	13,193	13,111	—	26,304	12,676	11,259	—	23,935
Inventory	14,997	4,359	—	19,356	8,722	3,538	—	12,260
Other current assets	3,979	6,442	56	10,477	3,731	6,787	40	10,558
Current assets — discontinued operations	$ 94,011	$ 32,509	$ 56	$126,576	$ 89,713	$ 29,848	$ 40	$119,601
Property, plant and equipment, net	$ 481,929	$ 74,714	$ —	$556,643	$ 487,753	$ 75,250	$ —	$563,003
Deferred income taxes	—	31,486	—	31,486	—	31,469	—	31,469
Other non-current assets	14,842	9,679	4,146	28,667	14,765	9,731	4,205	28,701
Non-current assets — discontinued operations	$ 496,771	$ 115,879	$ 4,146	$616,796	$ 502,518	$ 116,450	$ 4,205	$623,173
Current portion of long-term debt	$ 5,945	$ 48,973	$ —	$ 54,918	$ 6,206	$ 49,744	$ —	$ 55,950
Accounts payable — trade	9,237	24,715	3,692	37,644	3,057	23,037	3,998	30,092
Accrued interest	11,383	608	—	11,991	13,182	757	—	13,939
Other current liabilities	2,157	5,957	21	8,135	8,248	5,946	22	14,216
Current liabilities — discontinued operations	$ 28,722	$ 80,253	$ 3,713	$112,688	$ 30,693	$ 79,484	$ 4,020	$114,197
Long-term debt	$ 313,738	$ 19,779	$ —	$333,517	$ 313,738	$ 19,779	$ —	$333,517
Minority interest	31,640	422	—	32,062	31,879	406	—	32,285
Other non-current liabilities	184,779	9,202	—	193,981	184,972	8,110	—	193,082
Non-current liabilities — discontinued operations	$ 530,157	$ 29,403	$ —	$559,560	$ 530,589	$ 28,295	$ —	$558,884

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Predecessor Company December 31, 2002			
	Wholesale Power Generation	All Other		
		Wholesale Power Generation		
	Other North America	Other International	Alternative Energy	Total
	(In thousands)			
Cash and cash equivalents	$ 6,933	$ 40,740	$ 430	$ 48,103
Restricted cash	69,224	1,396	—	70,620
Receivables, net	17,645	29,693	296	47,634
Inventory	11,980	17,072	301	29,353
Derivative instruments valuation	—	29,795	—	29,795
Other current assets	2,107	10,526	376	13,009
Current assets — discontinued operations	$107,889	$ 129,222	$ 1,403	$ 238,514
Property, plant and equipment, net	$720,458	$ 535,695	$ 15,039	$1,271,192
Derivative instruments valuation	—	87,803	—	87,803
Other non-current assets	12,015	20,118	21,866	53,999
Non-current assets — discontinued operations	$732,473	$ 643,616	$ 36,905	$1,412,994
Current portion of long-term debt	$166,083	$ 462,570	$ 7,658	$ 636,311
Accounts payable — trade	19,321	47,359	1,141	67,821
Accrued income tax	4	22,422	(166)	22,260
Other current liabilities	18,201	14,689	6,339	39,229
Current liabilities — discontinued operations	$203,609	$ 547,040	$ 14,972	$ 765,621
Long-term debt	$334,200	$ 68,572	$ —	$ 402,772
Deferred income taxes	121	113,035	(2,102)	111,054
Derivative instruments valuation	—	43,891	—	43,891
Minority interest	28,791	1,344	216	30,351
Other non-current liabilities	769	13,763	—	14,532
Non-current liabilities — discontinued operations	$363,881	$ 240,605	$ (1,886)	$ 602,600

Bulo Bulo — In June 2002, we began negotiations to sell our 60% interest in Compania Electrica Central Bulo Bulo S.A. (Bulo Bulo), a Bolivian corporation. The transaction reached financial close in the fourth quarter of 2002 resulting in cash proceeds of $10.9 million (net of cash transferred of $8.6 million) and a loss of $10.6 million.

Crockett Cogeneration Project — In September 2002, we announced that we had reached an agreement to sell our 57.7% interest in the Crockett Cogeneration Project, a 240 MW natural gas fueled cogeneration plant near San Francisco, California, to Energy Investment Fund Group, an existing LP, and a unit of GE Capital. In November 2002, the sale closed and we realized net cash proceeds of approximately $52.1 million (net of cash transferred of $0.2 million) and a loss on disposal of approximately $11.5 million.

Csepel and Entrade — In September 2002, we announced that we had reached agreements to sell our Csepel power generating facilities (located in Budapest, Hungary) and our interest in Entrade (an electricity trading business headquartered in Prague) to Atel, an independent energy group headquartered in Switzerland. The sales of Csepel and Entrade closed before year-end and resulted in cash proceeds of $92.6 million (net of cash transferred of $44.1 million) and a gain of approximately $24.0 million. We accounted for the results of operations of Csepel and Entrade as part of our power generation segment within Europe.

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 LLC foreclosed on our membership interest in the NLGI subsidiaries and our equity interest in Minnesota Methane LLC. There was no material gain or loss recognized as a result of the foreclosure.

TERI — During 2002, we recorded an impairment charge of $11.7 million based on a revised project outlook. In September 2003, we completed the sale of TERI, a biomass waste-fuel power plant located in Florida and a wood processing facility located in Georgia, to DG Telogia Power, LLC. The sale resulted in net proceeds of approximately $1.0 million. We entered into an agreement to sell the wood processing facility on behalf of DG Telogia Power, LLC. This sale was completed during fourth quarter 2003 and we received cash consideration of approximately $1.0 million, resulting in a net gain on sale of approximately $1.0 million.

Peru Projects — In November 2003, we completed the sale of the Cahua and Pacasmayo (Peruvian Assets) resulting in net cash proceeds of approximately $16.2 million and a loss of $36.9 million. In addition, we expect to receive an additional consideration adjustment of approximately $2 million during 2004.

NEO Corporation — In August of 1995, we entered into a Marketing, Development and Joint Proposing Agreement, or "the Marketing Agreement", with Cambrian Energy Development LLC, or "Cambrian." Various claims had arisen in connection with this Marketing Agreement. In November 2003, we entered into a Settlement Agreement with Cambrian where we agreed to transfer our 100% interest in three gasco projects (NEO Ft. Smith, NEO Phoenix and NEO Woodville). During the third quarter of 2004, we completed the sale of four wholly owned entities — NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC, as well as the sale of several NEO investments — Four Hills LLC, Minnesota Methane II LLC, NEO Montauk Genco LLC and NEO Montauk Gasco LLC to Algonquin Power of Canada. Upon completion of the transaction, we received cash proceeds of $5.8 million, resulting in a $6.0 million gain associated with the four wholly owned entities sold and received cash proceeds of $6.1 million resulting in a loss of approximately $3.8 million attributable to the equity investments sold. The sale of these equity investments do not qualify for reporting purposes as discontinued operations.

McClain — We reviewed the recoverability of our McClain assets pursuant to SFAS No. 144 and recorded a charge of $100.7 million in the second quarter of 2003. On August 14, 2003, NRG's Board of Directors approved a plan to sell its 77% interest in McClain Generating Station, a 520 MW combined-cycle, natural gas-fired facility located in New Castle, Oklahoma. On August 18, 2003, we entered into an Asset Purchase Agreement with Oklahoma Gas & Electric Company pursuant to which we would, subject to the satisfaction of certain conditions, sell all of the McClain assets in a sale pursuant to Section 363 of the

Bankruptcy Codes as part of McClain's Chapter 11 proceeding that was subsequently filed on August 19, 2003. In accordance with Section 363 of the Bankruptcy Code and the terms of the Asset Purchase Agreement, we continued to seek alternative transactions that would provide greater value to us and our creditors than the transaction contemplated by the Asset Purchase Agreement.

As a result of the formalization of the plan to sell the McClain assets and the filing of petition under the Bankruptcy Code by McClain, McClain is being accounted for as a discontinued operation.

As part of our effort to seek alternative transactions that would provide greater value and in accordance with the bidding procedures approved by the Bankruptcy Court, we conducted an auction for the sale of McClain's assets, however no bids were submitted for the purchase of the assets. The Bankruptcy Court entered an order approving the terms of the sale with Oklahoma Gas & Electric free and clear of all liens. The closing of the sale is subject to various closing conditions including approval by the Federal Energy Regulatory Commission. Upon consummation of the asset sale, we anticipate that all proceeds from the sale will be used to repay outstanding project debt under the secured term loan and working capital facility. 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.

Penobscot Energy Recovery Company (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.

Note 7 — Write Downs and (Gains)/ Losses on Sales of Equity Method Investments

Investments accounted for by the equity method are reviewed for impairment in accordance with APB Opinion No. 18. APB Opinion 18 requires that a loss in value of an investment that is other than a temporary decline should be recognized. Gains are recognized on completion of the sale. Write downs and (gains)/

losses on sales of equity method investments recorded in operating expenses in the consolidated statement of operations includes the following:

	Predecessor Company	
	Year Ended December 31, 2002	For the Period January 1 – December 5, 2003
	(In thousands)	
NEO Corporation — Minnesota Methane	$ 12,292	$ 12,257
NEO Corporation — MM Biogas	3,251	2,613
Kondapalli	12,751	(519)
ECKG	—	(2,871)
Loy Yang	111,383	146,354
Mustang	—	(12,124)
Energy Development Limited (EDL)	14,220	—
Sabine River Works	48,375	—
Kingston	(9,876)	—
Mt. Poso	1,049	—
Powersmith	3,441	—
Collinsville Power Station	3,586	—
Other	—	1,414
Total write downs and (gains) losses of equity method investments	$ 200,472	$ 147,124

Write Downs of Equity Method Investments

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 LLC foreclosed on our membership interest in the NEO Landfill Gas, Inc. subsidiaries and our equity interest in Minnesota Methane LLC. Upon completion of the foreclosure, we recorded a gain of $2.2 million. This gain resulted from the release of certain obligations.

NEO Corporation — MM Biogas — We recorded an impairment charge of $3.2 million during 2002 to write-down our 50% investment in MM Biogas. This charge was related to revised project outlook and management's belief that the decline in fair value was other than temporary. In November 2003, we entered into a sales agreement with Cambrian Energy Development to sell our 50% interest in MM Biogas. We recorded an additional impairment charge of $2.6 million during the fourth quarter of 2003 due to developments related to the sale that indicated an impairment of our book value that was considered to be other than temporary.

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 sale agreement with the Genting Group of Malaysia, or "Genting", to sell our 30% interest in Lanco Kondapalli Power Pvt Ltd, or "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, we wrote down our investment in Kondapalli by

$1.3 million based on the final sale 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. 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 loss of less than $1.0 million. In accordance with the purchase agreement, we were to receive additional consideration if Atel purchased shares held by our partner. During the second quarter of 2003, we received approximately $3.7 million of additional consideration.

Loy Yang — Based on a third party market valuation and bids received in response to marketing Loy Yang for possible sale, we recorded a write down of our investment of approximately $111.4 million during 2002 ($53.6 million during the third quarter and an additional $57.8 million during the fourth quarter). This write-down reflected management's belief that the decline in fair value of the investment was other than temporary. Accumulated other comprehensive loss at December 31, 2002 included foreign currency translation losses of approximately $76.7 million related to Loy Yang.

In May 2003, we entered into negotiations that culminated in the completion of a Share Purchase Agreement to sell 100% of the Loy Yang project. Completion of the sale is subject to various conditions. Upon completion, the sale will result in proceeds of approximately $25.0 million to $31.0 million to us; however, the final sale proceeds will vary depending on the foreign exchange rate and purchase price adjustments. Consequently, we recorded an additional impairment charge of approximately $146.4 million during 2003.

Mustang Station — On July 7, 2003, we completed the sale of our 50% interest in Mustang Station, a gas-fired combined cycle power generating plant located in Denver City, Texas, to EIF Mustang Holdings I, LLC. The sale resulted in net cash proceeds of approximately $13.3 million and a net gain of approximately $12.1 million.

Energy Development Limited — On July 25, 2002, we announced that we completed the sale of our ownership interests in an Australian energy company, Energy Development Limited, or "EDL." EDL is a listed Australian energy company engaged in the development and management of an international portfolio of projects with a particular focus on renewable and waste fuels. In October 2002, we received proceeds of $78.5 million (AUS), or approximately $43.9 million (USD), in exchange for our ownership interest in EDL with the closing of the transaction. During the third quarter of 2002, we recorded a write-down of the investment of approximately $14.2 million to write down the carrying value of our equity investment due to the pending sale.

Sabine River — In September 2002, we agreed to transfer our indirect 50% interest in SRW Cogeneration LP, or "SRW", to our partner in SRW, Conoco, Inc. in consideration for Conoco's agreement to terminate or assume all of our obligations, in relation to SRW. SRW owns a cogeneration facility in Orange County, Texas. We recorded a charge of approximately $48.4 million during the quarter ended September 30, 2002 to write down the carrying value of our investment due to the pending sale. The transaction closed on November 5, 2002.

Kingston — In December 2002, we completed the sale of our 25% interest in Kingston Cogeneration LP, based near Toronto, Canada to Northland Power Income Fund. We received net proceeds of $15.0 million resulting in a gain on sale of approximately $9.9 million.

Mt. Poso — In September 2002, we agreed to sell our 39.5% indirect partnership interest in the Mt. Poso Cogeneration Company, a California limited partnership, or "Mt. Poso", for approximately $10 million to Red Hawk Energy, LLC. Mt. Poso owns a 49.5 MW coal-fired cogeneration power plant and thermally enhanced oil recovery facility located 20 miles north of Bakersfield, California. The sale closed in November 2002 resulting in a loss of approximately $1.0 million.

Powersmith — During the fourth quarter of 2002, we wrote down our investment in Powersmith in the amount of approximately $3.4 million due to recent developments, which indicated impairment of our book value that is considered to be other than temporary.

Collinsville Power Station — Based on third party market valuation and bids received in response to marketing the investment for possible sale, we recorded a write down of our investment of approximately $4.1 million during the second quarter of 2002. In August 2002, we announced that we had completed the sale of our 50% interest in the 192 MW Collinsville Power Station in Australia, to our partner, a subsidiary of Transfield Services Limited for $8.6 million (AUS), or approximately $4.8 million (USD). Our ultimate loss on the sale of Collinsville Power Station was approximately $3.6 million.

Note 8 — Other Charges (Credits)

Restructuring, impairment charges, legal settlement costs and fresh start adjustments included in operating expenses in the Consolidated Statement of Operations include the following:

	Predecessor Company		Reorganized NRG
	Year Ended December 31, 2002	For the Period January 1 – December 5, 2003	For the Period December 6 – December 31, 2003
		(In thousands)	
Impairment charges	$2,638,315	$ 228,896	**$ —**
Reorganization items	—	197,825	**2,461**
Restructuring charges	111,315	8,679	**—**
Legal settlement	—	462,631	**—**
Fresh Start adjustments	—	(3,895,541)	**—**
Total	$2,749,630	$(2,997,510)	**$ 2,461**
Less discontinued operations	186,570(1)	223,095(2)	**—**
Total — continuing operations	$2,563,060	$(3,220,605)	**$ 2,461**

(1) Consists of impairment charges.

(2) Consists of Fresh Start adjustments.

Impairment Charges

We review the recoverability of our long-lived assets in accordance with the guidelines of SFAS No. 144. As a result of this review, we recorded impairment charges of $2.5 billion and $228.9 million for the year ended December 31, 2002 and the period from January 1, 2003 through December 5, 2003 respectively, as shown in the table below.

To determine whether an asset was impaired, we compared asset carrying values to total future estimated undiscounted cash flows. Separate analyses were completed for assets or groups of assets at the lowest level for which identifiable cash flows were largely independent of the cash flows of other assets and liabilities. The estimates of future cash flows included only future cash flows, net of associated cash outflows, directly associated with and expected to arise as a result of our assumed use and eventual disposition of the asset. Cash flow estimates associated with assets in service were based on the asset's existing service potential. The cash flow estimates may include probability weightings to consider possible alternative courses of action and outcomes, given the uncertainty of available information and prospective market conditions.

If an asset was determined to be impaired based on the cash flow testing performed, an impairment loss was recorded to write down the asset to its fair value. Estimates of fair value were based on prices for similar assets and present value techniques. Fair values determined by similar asset prices reflect our current estimate of recoverability from expected marketing of project assets. For fair values determined by projected cash flows, the fair value represents a discounted cash flow amount over the remaining life of each project that reflects project-specific assumptions for long-term power pool prices, escalated future project operating costs, and expected plant operation given assumed market conditions.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Impairment charges (credits) included the following asset impairments (realized gains) for the year ended December 31, 2002 and for the period January 1, 2002 to December 5, 2003:

Project Name	Project Status	Predecessor Company Year Ended December 31, 2002	Predecessor Company For the Period January 1 - December 5, 2003	Fair Value Basis
		(In thousands)		
Devon Power LLC	Operating at a loss	$ —	$ 64,198	Projected cash flows
Middletown Power LLC	Operating at a loss	—	157,323	Projected cash flows
Arthur Kill Power, LLC	Terminated construction project	—	9,049	Projected cash flows
Langage (UK)	Terminated	42,333	(3,091)	Estimated market price/Realized gain
Turbine	Sold	—	(21,910)	Realized gain
Berrians Project	Terminated	—	14,310	Realized loss
Termo Rio	Terminated	—	6,400	Realized loss
Nelson	Terminated	467,523	—	Similar asset prices
Pike	Terminated	402,355	—	Similar asset prices
Bourbonnais	Terminated	264,640	—	Similar asset prices
Meriden	Terminated	144,431	—	Similar asset prices
Brazos Valley	Foreclosure completed in January 2003	102,900	—	Projected cash flows
Kendall, Batesville & other expansion projects	Terminated	120,006	—	Projected cash flows
Turbines & equipment	Equipment being marketed	701,573	—	Similar asset prices
Audrain	Operating at a loss	66,022	—	Projected cash flows
Somerset	Operating at a loss	49,289	—	Projected cash flows
Bayou Cove	Operating at a loss	126,528	—	Projected cash flows
Hsin Yu	Operating at a loss	121,864	—	Projected cash flows
Other		28,851	2,617	
Total impairment charges (credits)		2,638,315	228,896	
Less Discontinued Operations				
Hsin Yu		121,864	—	Projected cash flows
Batesville		64,706	—	Projected cash flows
Impairment charges		$2,451,745	$ 228,896	

Credit rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity experienced during the third quarter of 2002 were “triggering events” which required us to review the recoverability of our long-lived assets. Adverse economic conditions resulted in declining energy prices. Consequently, we determined that many of our construction projects and operational projects were impaired during the third quarter of 2002 and should be written down to fair market value.

Table of Contents

Connecticut Facilities — As a result of regulatory developments and changing circumstances in the second quarter of 2003, we updated the facilities' cash flow models to incorporate changes to reflect the impact of the April 25, 2003 FERC's orders on regional and locational pricing, and to update the estimated impact of future locational capacity or deliverability requirements. Based on these revised cash flow models, management determined that the new estimates of pricing and cost recovery levels were not projected to return sufficient revenue to cover the fixed costs at Devon Power LLC and Middletown Power LLC. As a consequence, during the second quarter of 2003 we recorded $64.2 million and $157.3 million as impairment charges for Devon Power LLC and Middletown Power LLC, respectively.

Langage (UK) — During the third quarter of 2002, we reviewed the recoverability of our Langage assets pursuant to SFAS No. 144 and recorded a charge of $42.3 million. In August 2003 we closed on the sale of Langage to Carlton Power Limited resulting in net cash proceeds of approximately $1.5 million, of which $1.0 million was received in 2003 and $0.5 million during the first quarter of 2004, and a net gain of approximately $3.1 million.

Arthur Kill Power, LLC — During the third quarter of 2003, we cancelled our plans to re-establish fuel oil capacity at our Arthur Kill plant. This resulted in a charge of approximately $9.0 million to write-off assets under development.

Turbines — In October 2003, we closed on the sale of three turbines and related equipment. The sale resulted in net cash proceeds of $70.7 million and a gain of approximately $21.9 million.

Berrians Project — During the fourth quarter of 2003, we cancelled plans to construct the Berrians peaking facility on the land adjacent to our Astoria facility. Berrians was originally scheduled to commence operations in the summer of 2005; however, based on the remaining costs to complete and the current risk profile of merchant peaking units, the construction project was terminated. This resulted in a charge of approximately $14.3 million to write off the project's assets.

Termo Rio — Termo Rio is a 1040 green field cogeneration project located in the state of Rio de Janeiro, Brazil. Based on the project's failure to meet certain key milestones, we exercised our rights under the project agreements to sell our debt and equity interests in the project to our partner. We are in arbitration over the amount of compensation we are to receive for our interests in the project. Based on continued negotiations aimed at settling the case and the positions of the parties in the arbitration we recorded an impairment charge of $6.4 million to reflect our investment interest at the amount expected to be recovered through a sale. On March 8, 2003, the arbitral tribunal decided most, but not all, of the issues in our favor. The final amount of the arbitral award to NRG has not been conclusively determined and the parties may seek to modify or challenge the award. We believe we will recover the amount we have recorded on our balance sheet.

There were no impairment charges for the period December 6, 2003 through December 31, 2003.

Reorganization Items

For the period from January 1, 2003 to December 5, 2003, we incurred $197.8 million in reorganization costs and for the period from December 6, 2003 to December 31, 2003 we incurred $2.5 million in reorganization costs. All reorganization costs have been incurred since we filed for bankruptcy in May 2003. The following table provides the detail of the types of costs incurred:

	Predecessor Company	Reorganized NRG
	For the Period January 1-December 5, 2003	For the Period December 6-December 31, 2003
	(In thousands)	
Reorganization items		
Professional fees	$ 82,186	$ 2,461
Deferred financing costs	55,374	—
Pre-payment settlement	19,609	—
Interest earned on accumulated cash	(1,059)	—
Contingent equity obligation	41,715	—
Total reorganization items	$ 197,825	$ 2,461

Restructuring Charges

We incurred total restructuring charges of approximately $111.3 million for the year ended December 31, 2002. These costs consisted of employee separation costs and advisor fees. We incurred an additional $8.7 million of employee separation costs and advisor fees during 2003 until we filed for bankruptcy in May 2003. Subsequent to that date we recorded all advisor fees as reorganization costs.

Legal Settlement

During the third quarter of 2003, we recorded $396.0 million in connection with the resolution of the FirstEnergy Arbitration Claim. As a result of this resolution, FirstEnergy retained ownership of the Lake Plant Assets and received an allowed general unsecured claim of $396.0 million under the NRG plan of reorganization submitted to the Bankruptcy Court.

In November 2003, we settled various litigation with Fortistar Capital in which Fortistar Capital released us from all litigation claims in exchange for a $60.0 million pre-petition claim and an $8.0 million post-petition claim. We had previously recorded $10.8 million in connection with various legal disputes with Fortistar Capital; accordingly, we recorded an additional $57.2 million during November 2003.

In August of 1995, we entered into a Marketing, Development and Joint Proposing Agreement, “the Marketing Agreement”, with Cambrian Energy Development LLC, or “Cambrian.” Various claims had arisen in connection with this Marketing Agreement. In November 2003, we entered into a Settlement Agreement with Cambrian where we agreed to transfer our 100% interest in three gasco

projects (NEO Ft. Smith, NEO Phoenix and NEO Woodville) and our 50% interest in two genco projects (MM Phoenix and MM Woodville) to Cambrian. In addition, we agreed to pay approximately $1.8 million in settlement of royalties incurred in connection with the Marketing Agreement. We had previously recorded a liability for royalties owed to Cambrian therefore we recorded an additional $1.4 million during November 2003.

In November 2003, we settled our dispute with Dick Corporation in connection with Meriden Gas Turbines, which resulted in our recording an additional liability of $8.0 million in November 2003.

Fresh Start Adjustments

During the fourth quarter of 2003, we recorded a net credit of $3.9 billion (comprised of a $4.1 billion gain from continuing operations and a $0.2 billion loss from discontinued operations) in connection with fresh start adjustments as discussed in Note 3. Following is a summary of the significant effects of the reorganization and Fresh Start:

	(In millions)
Discharge of corporate level debt	$ 5,162
Discharge of other liabilities	811
Establishment of creditor pool	(1,040)
Receivable from Xcel	640
Revaluation of fixed assets	(1,392)
Revaluation of equity investments	(207)
Valuation of SO(2) emission credits	374
Valuation of out of market contracts, net	(400)
Fair market valuation of debt	108
Valuation of pension liabilities	(61)
Other valuation adjustments	(100)
Total Fresh Start adjustments	3,895
Less discontinued operations	224
Total Fresh Start adjustments — continuing operations	$ 4,119

Note 9 — Asset Retirement Obligation

Effective January 1, 2003, we adopted SFAS No. 143, *"Accounting for Asset Retirement Obligations"* or "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.

We identified certain retirement obligations within our power generation operations related to our North America projects in the South Central region, the Northeast region, Australia, our Alternative Energy projects and our Thermal projects. 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. We also identified other asset retirement obligations including plant dismantlement 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 $2.6 million increase to property, plant and equipment and a $4.2 million increase to other long-term obligations. The cumulative effect of adopting SFAS No. 143 was recorded as a $0.6 million increase to depreciation expense and a $1.6 million increase to cost of majority-owned operations in the period from January 1, 2003 to December 5, 2003 as we considered the cumulative effect to be immaterial.

The following represents the balances of the asset retirement obligation as of January 1, 2003 and the additions and accretion of the asset retirement obligation for the periods January 1, 2003 through December 5, 2003 and the period of December 6, 2003 through December 31, 2003, which is included in other long-term obligations in the consolidated balance sheet. Prior to December 5, 2003, we completed our annual review of asset retirement obligations. As part of that review we made revisions to our previously recorded obligation in the amount of $4.0 million. The revisions included identification of new obligations as well as changes in costs or procedures required at retirement date. As a result of adopting Fresh Start we revalued our asset retirement obligations on December 6, 2003. We recorded an additional asset retirement obligation of $7.3 million in connection with fresh start reporting. This amount results from a change in the discount rate used between adoption and fresh starting reporting as of December 5, 2003, equal to 500 to 600 basis points.

	Predecessor Company					Reorganized NRG		
Description	Beginning Balance January 1, 2003	Revisions to Estimate	Accretion for Period Ended December 5, 2003	Adjustment for Fresh Start Reporting	Ending Balance December 5, 2003	Beginning Balance December 6, 2003	Accretion for Period December 6 - December 31, 2003	Ending Balance December 31, 2003
	(In thousands)							
South Central Region	$ 396	$ —	$ 57	$ 2,170	$ 2,623	$ 2,623	$ 15	$ 2,638
Northeast Region	2,045	4,034	634	4,978	11,691	11,691	59	11,750
Australia	5,834	—	3,282	—	9,116	9,116	322	9,438
Alternative Energy	629	—	73	128	830	830	5	835
Thermal	1,171	9	93	53	1,326	1,326	7	1,333
Total asset retirement obligation	$ 10,075	$ 4,043	$ 4,139	$ 7,329	$ 25,586	$ 25,586	$ 408	$ 25,994

The following represents the pro-forma effect on our net income for the twelve months ended December 31, 2001 and 2002, as if we had adopted SFAS No. 143 as of January 1, 2001:

	Predecessor Company		
	Twelve Months Ended December 31, 2001	Twelve Months Ended December 31, 2002	For the Period January 1 - December 5, 2003
	(In thousands)		
Income (loss) from continuing operations as reported	$ 210,502	$(2,788,452)	$2,949,078
Pro-forma adjustment to reflect retroactive adoption of SFAS No. 143	(1,564)	(677)	2,154
Pro-forma income (loss) from continuing operations	$ 208,938	$(2,789,129)	$2,951,232
Net income (loss) as reported	$ 265,204	$(3,464,282)	$2,766,445
Pro-forma adjustment to reflect retroactive adoption of SFAS No. 143	(1,564)	(677)	2,154
Pro-forma net income (loss)	$ 263,640	$(3,464,959)	$2,768,599

On a pro forma basis an Asset Retirement obligation of $8.4 million and $10.1 million would have been recorded as an other long-term obligation as of January 1, 2002 and December 31, 2002, based on similar assumptions used to determine the amounts on our balance sheet as of December 6, 2003 and December 31, 2003.

Note 10 — Inventory

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

	Predecessor Company	Reorganized NRG	
	December 31, 2002	December 6, 2003	December 31, 2003
		(In thousands)	
Fuel oil	$ 51,443	$ 69,799	$ 71,861
Coal	82,554	63,641	59,555
Natural gas	153	377	856
Other fuels	2,852	9,874	10,156
Spare parts	109,311	66,024	58,863
Emission credits	14,742	4,478	4,478
Other	6,301	203	207
Total inventory	267,356	214,396	205,976
Less discontinued operations	13,344	18,160	11,050
Total inventory — continuing operations	$ 254,012	$ 196,236	$ 194,926

Note 11 — 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:

	Predecessor Company	Reorganized NRG	
	December 31, 2002	December 6, 2003	December 31, 2003
		(In thousands)	
Investment in Bonds			
Audrain County, due December 2023, 10%	$ 239,930	**$ 239,930**	**$ 239,930**
NRG Pike LLC Mississippi Industrial Revenue Bonds due May 2010, 7.1%	155,477	**—**	**—**
Investment in bonds	395,407	**239,930**	**239,930**

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Predecessor Company	Reorganized NRG	
	December 31, 2002	December 6, 2003	December 31, 2003
		(In thousands)	
Notes Receivables			
Triton Coal Co., note due December 2003, non-interest bearing	3,000	**1,500**	**—**
O'Brien Cogen II note, due 2008, non-interest bearing	627	**686**	**692**
Southern Minnesota-Prairieland Solid Waste, note due 2003, 7%	12	**—**	**—**
Omega Energy, LLC, due 2004, 12.5%	4,145	**3,708**	**3,708**
Omega Energy, LLC, due 2009, 11%	1,533	**1,583**	**1,583**
Northbrook Carolina Hydro II, LLC, due November 2005, 8.5%	—	**86**	**84**
Elk River — GRE, due December 31, 2008, non-interest bearing	1,837	**1,564**	**1,564**
NRG Processing Solutions	—	**134**	**134**
Audrain Generating LLC	—	**—**	**118**
Termo Rio (via NRGenerating Luxembourg (No. 2) S.a.r.l, due 20 years after plant becomes operational, 19.5%	63,723	**57,323**	**57,323**
SET PERC Investment, LLC, due December 31, 2005, 7%	7,320	**—**	**—**
Notes receivables and bonds — non-affiliates	477,604	**306,514**	**305,136**
NEO notes to various affiliates due primarily 2012, prime +2%	9,538	**9,419**	**9,419**
NRG (LSP Nelson)	—	**—**	**200**
Kladno Power (No. 1) B.V.	2,442	**—**	**—**
Kladno Power (No. 2) B.V. notes to various affiliates, non-interest bearing	46,801	**—**	**—**
Saale Energie Gmbh, indefinite maturity date, 4.75%-7.79%	86,246	**107,391**	**111,892**
Northbrook Texas LLC, due February 2024, 9.25%	8,967	**8,841**	**8,841**
Notes receivable — affiliates	153,994	**125,651**	**130,352**
Reserve for Uncollectible Notes Receivable	(7,320)	**—**	**—**

	Predecessor Company	Reorganized NRG	
	December 31, 2002	December 6, 2003	December 31, 2003
		(In thousands)	
Other			
Saale Energia GmbH, due August 31, 2021, 13.88% (direct financing lease)	366,417	**435,045**	**451,449**
Subtotal	990,695	**867,210**	**886,937**
Less current maturities	54,711	**66,628**	**65,341**
Total	$ 935,984	**$ 800,582**	**$ 821,596**

Investment in bonds is comprised of marketable debt securities. These securities consist of municipal bonds of Audrain County, Missouri and Mississippi Industrial Revenue Bonds. The Audrain County bonds mature in 2023 and the Mississippi Industrial bonds mature in 2010. These investments in bonds are classified as held to maturity and are recorded at amortized cost. The carrying value of these bonds approximates fair value. Both the Audrain County bonds and the Mississippi Industrial Revenue Bonds are pledged as collateral for the related debt owed to each county. As further described in Note 17, each of these transactions have offsetting obligations.

Note 12 — Property, Plant and Equipment

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

	Depreciable Lives	Predecessor Company December 31, 2002	Reorganized NRG December 6, 2003	Reorganized NRG December 31, 2003	Average Remaining Useful Life
			(In thousands)		
Facilities and equipment	10-60 Years	$6,258,744	**$4,125,308**	**$4,141,711**	**26**
Land and improvements		102,624	**101,577**	**101,577**	
Office furnishings and equipment	3-15 Years	67,030	**34,676**	**34,673**	**3**
Construction in progress		633,307	**144,426**	**151,467**	
Total property, plant and equipment		7,061,705	**4,405,987**	**4,429,428**	
Accumulated depreciation		(596,403)	**—**	**(13,041)**	
Net property, plant and equipment		6,465,302	**4,405,987**	**4,416,387**	
Less discontinued operations		664,027	**397,189**	**403,551**	
Net property, plant and equipment		$5,801,275	**$4,008,798**	**$4,012,836**	

Included in construction in progress at December 31, 2002 is approximately $248.9 million related to turbines associated with cancelled projects. As of December 5, 2003 and December 31, 2003, $88.6 million of turbine cost associated with cancelled projects has been reclassified to the other asset line in the accompanying balance sheet.

Note 13 — Investments Accounted for by the Equity Method

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

A summary of certain of our more significant equity-method investments, which were in operation at December 31, 2003, is as follows:

Name	Geographic Area	Economic Interest
West Coast Power		
El Segundo Power	USA	50%
Long Beach Generating	USA	50%
Encina	USA	50%
San Diego Combustion Turbines	USA	50%
Other		
Gladstone Power Station	Australia	38%
Loy Yang Power A	Australia	25%
MIBRAG GmbH	Europe	50%
Enfield	Europe	25%
Scudder LA Power Fund I	Latin America	25%
Rocky Road Power	USA	50%
Commonwealth Atlantic	USA	50%
NRG Saguaro LLC	USA	50%
James River Cogen	USA	50%

Summarized financial information for investments in unconsolidated affiliates accounted for under the equity method is as follows:

	Predecessor Company			Reorganized NRG
	Year Ended December 31,		For the Period January 1 – December 5,	For the Period December 6 – December 31,
	2001	2002	2003	2003
	(In thousands)			
Operating revenues	$3,070,078	$2,394,256	$2,212,280	$ 268,348
Costs and expenses	2,658,168	2,284,582	2,035,812	202,725
Net income	$ 411,910	$ 109,674	$ 176,468	$ 65,623
Current assets	$1,425,175	$1,069,239	$ 783,669	$ 829,525
Noncurrent assets	7,009,862	6,853,250	6,452,014	6,541,003
Total assets	$8,435,037	$7,922,489	$7,235,683	$7,370,528
Current liabilities	$1,192,630	$1,075,785	$1,215,827	$1,275,724
Noncurrent liabilities	4,533,168	3,861,285	3,528,600	3,592,342
Equity	2,709,239	2,985,419	2,491,256	2,502,462
Total liabilities and equity	$8,435,037	$7,922,489	$7,235,683	$7,370,528
NRG's share of equity	$1,050,510	$1,171,726	$1,079,336	$1,051,959
NRG's share of net income	$ 210,032	$ 68,996	$ 170,901	$ 13,521

West Coast Power LLC Summarized Financial Information

We have a 50% interest in one company (West Coast Power LLC) that was considered significant as of December 31, 2003, as defined by applicable SEC regulations, we account for our investment using the equity method. Upon adoption of Fresh Start we adjusted our investment in West Coast Power to fair value as of December 6, 2003. In accordance with APB Opinion 18, we have reconciled the value of our investment as of December 6, 2003 to our share of West Coast Powers partner's equity. As a result of pushing down the impact of Fresh Start to the projects balance sheet we determined that a contract based intangible asset with a one year remaining life, consisting of the value of West Coast Power's CDWR energy sales contract, must be established and recognized as a basis adjustment to our share of the future earnings generated by West Coast Power. This adjustment will reduce our equity earnings in the amount of approximately $10.4 million per month during 2004 until the contract expires in December 2004. Offsetting this reduction in earnings is a favorable adjustment to reflect a lower depreciation expense resulting from the corresponding reduced value of the project's fixed assets from Fresh Start reporting. During the period December 6, 2003 through December 31, 2003 we recorded equity earnings of $9.4 million for West Coast Power after adjustments for the reversal of $2.6 million project level depreciation expense, offset by a decrease in earnings related to $8.8 million amortization of the intangible asset for the CDWR contract. The following table summarizes financial information for West Coast Power LLC, including interests owned by us and other parties for the periods shown below:

Results of Operations

	Year Ended December 31, 2001	Year Ended December 31, 2002	For the Period January 1 – December 5, 2003	For the Period December 6 – December 31, 2003
			(In millions)	
Operating revenues	$1,562	$585	$ 643	$ 53
Operating income	345	48	201	31
Net income (pre-tax)	326	34	202	31

Financial Position

	December 31, 2002	December 6, 2003	December 31, 2003
		(In millions)	
Current assets	$ 255	$ 247	$ 257
Other assets	532	454	454
Total assets	$ 787	$ 701	$ 711
Current liabilities	$ 112	$ 58	$ 55
Other liabilities	34	1	8
Equity	641	642	648
Total liabilities and equity	$ 787	$ 701	$ 711

Note 14 — Decommissioning Funds

We are required by the State of Louisiana Department of Environmental Quality, or "DEQ", to rehabilitate our Big Cajun II ash and wastewater impoundment areas, subsequent to the Big Cajun II facilities' removal from service. On July 1, 1989, a guarantor trust fund, or "the Solid Waste Disposal Trust Fund", was established to accumulate the estimated funds necessary for such purpose. Approximately $1.1 million was initially deposited in the Solid Waste Disposal Trust Fund in 1989, and $116,000 has been funded 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. At December 31, 2002, December 6, 2003 and December 31, 2003, the carrying value of the trust fund investments was approximately $4.6 million, $4.8 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. The amounts required to be deposited in this trust fund are separate from our calculation of the asset retirement obligation recorded for the Big Cajun II ash and wastewater impoundment areas discussed in Note No. 9.

Note 15 — Goodwill and Other Intangible Assets

During the first quarter of 2002, we adopted SFAS No. 142 — *"Goodwill and Other Intangible Assets"* or "SFAS No. 142", which requires new accounting for intangible assets, including goodwill. Intangible assets with finite lives will be amortized over their economic useful lives and periodically reviewed for impairment. Goodwill will no longer be amortized, but will be tested for impairment annually and on an interim basis if an event occurs or a circumstance changes between annual tests that may reduce the fair value of a reporting unit below its carrying value. Upon the adoption of Fresh Start, we re-evaluated the recoverability of our goodwill and intangibles. As a result, we have written off all goodwill amounts as of December 5, 2003. We have also established certain other contract based intangibles, which will be amortized over their respective contractual lives.

Predecessor Company

We had intangible assets with a net carrying value of $75.1 million at December 31, 2002. The Aggregate amortization expense recognized for the years ended December 31, 2002 and 2001 was approximately $2.7 million and $4.1 million, respectively. The amortization expense for the period January 1, 2003 through December 5, 2003 was $3.8 million.

Reorganized NRG

We had intangible assets with a net carrying value of $484.7 million and $432.4 million at December 6, 2003 and December 31, 2003. The power purchase agreements will be amortized as a reduction to revenue over the terms and conditions of each contract. The weighted average amortization period is 7 years for the power purchase agreements. Emission allowances will be amortized as additional fuel expense based upon the actual level of emissions from the respective plant through 2023. The amortization expense for the period December 6, 2003 through December 31, 2003 was $5.2 million related to power purchase agreements. The annual aggregate amortization expense for each of the five succeeding years is expected to approximate $57.2 million in year one, $37.2 million in year two, $30.0 million in years three and four, and $23.1 million in year five for both the power purchase agreements and emission allowances. Intangible assets consisted of the following:

	Predecessor Company		Reorganized NRG			
	At December 31, 2002		At December 6, 2003		At December 31, 2003	
Description	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Amortization Accumulated
			(In thousands)			
Goodwill*	$32,958	$ 6,123	$ —	—	$ —	$ —
Intangibles:						
Service contracts*	65,791	15,987	—	—	—	—
Less discontinued operations	2,000	492				
	63,791	15,495				
Power purchase agreements			**113,209**	**—**	**66,114**	**5,230**
Less discontinued operations	—	—	**2,059**	**—**	**2,059**	**18**
			111,150		**64,055**	**5,212**
Emission allowances**	—	—	**373,518**	**—**	**373,518**	**—**
Total intangibles	$63,791	$ 15,495	**$484,668**	**$ —**	**$437,573**	**$ 5,212**

* Written off as part of Fresh Start since service contracts determined to be at current market rates.

** No amortization recorded in 2003 as this balance includes only emission allowances for 2004 and beyond. All emission allowances for 2003 were used prior to December 5, 2003.

The following table summarizes the pro forma impact of implementing SFAS No. 142 at January 1, 2001 on net income (loss) for the periods presented.

	Predecessor Company		
	Year Ended December 31,		For the Period January 1 - December 5,
	2001	2002	2003
		(In thousands)	
Reported income/(loss) from continuing operations	$210,049	$(2,791,200)	$2,947,262
Add back: Goodwill amortization (after-tax)	923	—	—
Less discontinued operations	(95)	—	—
Adjusted income/(loss) from continuing operations	$210,877	$(2,791,200)	$2,947,262
Reported net income/(loss)	$265,204	$(3,464,282)	$2,766,445
Add back: Goodwill amortization (after-tax)	2,919	—	—
Adjusted net income/(loss)	$268,123	$(3,464,282)	$2,766,445

Note 16 — Accounting for Derivative Instruments and Hedging Activities

We have adopted Statement of Financial Accounting Standards No. 133, *"Accounting for Derivative Instruments and Hedging Activities"* or "SFAS No. 133", as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 149. SFAS No. 133 requires us to record all derivatives on the balance sheet at fair value. Changes in the fair value of non-hedge derivatives will be immediately recognized in earnings. The criteria used to determine if hedge accounting treatment is appropriate are a) the designation of the hedge to an underlying exposure, b) whether or not the overall risk is being reduced and c) if there is a high degree of correlation between the value of the derivative instrument and the underlying obligation. Formal documentation of the hedging relationship, the nature of the underlying risk, the risk management objective, and the means by which effectiveness will be assessed is created at the inception of the hedge. Changes in fair values of derivatives accounted for as hedges will either be recognized in earnings as offsets to the changes in fair value of related hedged assets, liabilities and firm commitments or, for forecasted transactions, deferred and recorded as a component of other accumulated comprehensive income, or "OCI", until the hedged transactions occur and are recognized in earnings. The ineffective portion of a hedging derivative instrument's change in fair value will be immediately recognized in earnings. We also formally assess both at inception and at least quarterly thereafter, whether the derivatives that are used in hedging transactions are highly effective in offsetting the changes in either the fair value or cash flows of the hedged item. This assessment includes all components of each derivative's gain or loss unless otherwise noted. When it is determined that a derivative ceases to be a highly effective hedge, hedge accounting is discontinued.

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 swaps used to mitigate the risks associated with movements in interest rates and foreign exchange contracts to reduce the effect of fluctuating foreign currencies on foreign denominated investments and other transactions. At December 31, 2003, we had commodity contracts extending through December 2020.

Derivative Financial Instruments

Foreign Currency Exchange Rates

As of December 6, 2003 and December 31, 2003, neither we nor our consolidating subsidiaries had any outstanding foreign currency exchange contracts. At December 31, 2002, we had various foreign currency exchange instruments with combined notional amounts of $3.0 million. These foreign currency exchange instruments were hedges of expected future cash flows. If the hedges had been terminated at December 31, 2002, we would have owed the counter-parties $0.3 million.

Interest Rates

At December 31, 2002, December 6, 2003 and December 31, 2003, our consolidating subsidiaries had various interest-rate swap agreements with combined notional amounts of $1.7 billion, $617.4 million and $620.5 million, respectively. These contracts are used to manage our exposure to changes in interest rates. If these swaps had been terminated at December 31, 2002, December 6, 2003 and December 31, 2003, we would have owed the counter-parties $41.0 million, $53.6 million and $50.2 million, respectively.

Energy Related Commodities

At December 31, 2002, December 6, 2003 and December 31, 2003, we had various energy related commodities financial instruments with combined notional amounts of $241.8 million, $519.7 million and $521.1 million, respectively. These financial instruments take the form of fixed price, floating price or indexed sales or purchases, options, such as puts or calls, basis transactions and swaps. These contracts are used to manage our exposure to commodity price variability in electricity, emission allowances and natural gas, oil and coal used to meet fuel requirements. If these contracts were terminated at December 31, 2002, December 6, 2003 and December 31, 2003, we would have received $58.5 million, $46.3 million and $46.0 million, from counter-parties, respectively. As of December 31, 2003, we had various long-term power sales contracts with combined notional amounts of approximately $3.2 billion.

Credit Risk

We have an established credit policy in place to minimize our overall credit risk. Important elements of this policy include ongoing financial reviews of all counter-parties, established credit limits, as well as monitoring, managing and mitigating credit exposure.

Accumulated Other Comprehensive Income

The following table summarizes the effects of SFAS No. 133 on our other comprehensive income balance as of December 31, 2003:

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Accum. OCI balance at December 6, 2003	$ —	$ —	$ —	$ —
Unwound from OCI during period:				
— due to unwinding of previously deferred amounts	—	—	—	—
Mark to market of hedge contracts	(1,953)	1,600	(170)	(523)
Accum. OCI balance at December 31, 2003	$ (1,953)	$1,600	$ (170)	$ (523)
Gains/(Losses) expected to unwind from OCI during next 12 months	$ 1,323	$ 745	$ —	$2,068

During the period ended December 31, 2003, we recorded a loss in OCI of approximately $0.5 million 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 December 31, 2003 was an unrecognized loss of approximately $0.5 million. We expect $2.1 million of deferred net gains on derivative instruments accumulated in OCI to be recognized in earnings during the next twelve months.

The following table summarizes the effects of SFAS No. 133 on our other comprehensive income balance as of December 6, 2003:

	Predecessor Company			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Accum. OCI balance at January 1, 2003	$ 129,496	$(102,957)	$ (261)	$ 26,278
Unwound from OCI during period:				
— due to forecasted transactions probable of no longer occurring	—	32,025	—	32,025
— due to unwinding of previously deferred amounts	(112,501)	(2,280)	—	(114,781)
Mark to market of hedge contracts	43,979	7,358	56	51,393
Accum. OCI balance at December 5, 2003	60,974	(65,854)	(205)	(5,085)
— due to Fresh Start reporting write-off	(60,974)	65,854	205	5,085
Accum. OCI balance at December 6, 2003	$ —	$ —	$ —	$ —

During the period ended December 5, 2003, we reclassified losses of $32.0 million from OCI to current-period earnings as a result of the discontinuance of cash flow hedges because it is probable that the original forecasted transactions will not occur by the end of the originally specified time period. Additionally, gains of $114.8 million were reclassified from OCI to current period earnings during the period ended December 5, 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 period ended December 5, 2003, we recorded a gain in OCI of approximately $51.4 million related to changes in the fair values of derivatives accounted for as hedges. Our plan of reorganization became effective December 5, 2003 and, accordingly, we made adjustments for Fresh Start in accordance with SOP 90-7. These Fresh Start adjustments resulted in a write-off of net losses recorded in OCI of $5.1 million.

The following table summarizes the effects of SFAS No. 133 on our other comprehensive income balance as of December 31, 2002:

	Predecessor Company			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Accum. OCI balance at December 31, 2001	$ 142,919	$ (69,455)	$(2,363)	$ 71,101
Unwound from OCI during period:				
— due to forecasted transactions probable of no longer occurring	—	(23,263)	—	(23,263)
— due to termination of hedged items by counterparty	(6,130)	—	—	(6,130)
— due to unwinding of previously deferred amounts	(77,576)	22,337	2,075	(53,164)
Mark to market of hedge contracts	70,283	(32,576)	27	37,734
Accum. OCI balance at December 31, 2002	$ 129,496	$(102,957)	$ (261)	$ 26,278

During the year ended December 31, 2002, we reclassified gains of $23.3 million from OCI to current-period earnings as a result of the discontinuance of cash flow hedges because it is probable that the original forecasted transactions will not occur by the end of the originally specified time period. Also, gains of $6.1 million were reclassified from OCI to current period earnings due to the hedge items being terminated by the counterparties. Additionally, gains of $53.2 million were reclassified from OCI to current period earnings during the year ended December 31, 2002 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 year ended December 31, 2002, we recorded a gain in OCI of approximately $37.7 million 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 December 31, 2002 was an unrecognized gain of approximately $26.3 million.

Statement of Operations

The following tables summarize the effects of SFAS No. 133 on our statement of operations for the period from December 6, 2003 through December 31, 2003:

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Revenue from majority owned subsidiaries	$ (627)	$ —	$ —	$ (627)
Cost of operations	508	—	—	508
Other income	—	—	—	—
Equity in earnings of unconsolidated subsidiaries	(630)	—	—	(630)
Interest expense	—	1,983	—	1,983
Total Statement of Operations impact before tax	$ (749)	$1,983	$ —	$1,234

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following tables summarize the effects of SFAS No. 133 on our statement of operations for the period from January 1, 2003 through December 5, 2003:

	Predecessor Company			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Revenue from majority owned subsidiaries	$ 30,027	$ —	$ —	$ 30,027
Cost of operations	4,607	—	—	4,607
Other income	—	—	92	92
Equity in earnings of unconsolidated subsidiaries	19,022	—	—	19,022
Interest expense	—	(15,104)	—	(15,104)
Total Statement of Operations impact before tax	$ 53,656	$(15,104)	$ 92	$ 38,644

The following tables summarize the effects of SFAS No. 133 on our statement of operations for the period ended December 31, 2002:

	Predecessor Company			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Revenue from majority owned subsidiaries	$ 9,085	$ —	$ —	$ 9,085
Cost of operations	9,530	—	—	9,530
Equity in earnings of unconsolidated subsidiaries	1,426	970	—	2,396
Other income	—	—	344	344
Interest expense	—	(32,953)	—	(32,953)
Total Statement of Operations impact before tax	$ 20,041	$(31,983)	$ 344	$(11,598)

The following tables summarize the effects of SFAS No. 133 on our statement of operations for the period ended December 31, 2001:

	Predecessor Company		
	Energy Commodities	Foreign Currency	Total
	(Gains/(Losses) in thousands)		
Revenue from majority owned subsidiaries	$ (8,138)	$ —	$ (8,138)
Cost of operations	17,556	—	17,556
Equity in earnings of unconsolidated subsidiaries	4,662	—	4,662
Other income	—	252	252
Total Statement of Operations impact before tax	$ 14,080	$ 252	$14,332

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 enter 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 shareholders' 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 years ended December 31, 2001, December 31, 2002 or during the periods January 1, 2003 through December 5, 2003 and December 6, 2003 through December 31, 2003.

Our pre-tax earnings for the years ended December 31, 2001, December 31, 2002, the period January 1, 2003 through December 5, 2003 and the period December 6, 2003 through December 31, 2003, were affected by an unrealized gain of $14.1 million, an unrealized gain of $20.0 million, an unrealized gain of $53.7 million and an unrealized loss of $0.7 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.

During the year ended December 31, 2002, we reclassified gains of $83.7 million from OCI to current-period earnings. During the periods January 1, 2003 through December 5, 2003 and December 6, 2003 through December 31, 2003 gains of $112.5 and $0 million, respectively, were reclassified from OCI to current-period earnings. Our plan of reorganization became effective December 5, 2003 and, accordingly, we made adjustments for Fresh Start in accordance with SOP 90-7. These Fresh Start adjustments resulted in a write-off of net gains recorded in OCI of $61.0 million on energy related derivative instruments accounted for as hedges. We expect to reclassify an additional $1.3 million of deferred gains to earnings during the next twelve months on energy related derivative instruments accounted for as hedges.

Interest Rates

To manage interest rate risk, we have entered into interest-rate swaps that effectively fix the interest payments of certain floating rate debt instruments. Interest-rate swap agreements are accounted for as cash flow hedges. The effective portion of the cumulative gain or loss on the derivative instrument is reported as a component of OCI in shareholders' equity and recognized into earnings as the underlying interest expense is incurred. 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 interest rate cash flow hedges during the years ended December 31, 2001 and December 31, 2002 or during the periods January 1, 2003 through December 5, 2003 and December 6, 2003 through December 31, 2003.

Our pre-tax earnings for the years ended December 31, 2001 and 2002 were increased by an unrealized loss of $0 and $32.0 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.

Our pre-tax earnings for the period January 1, 2003 through December 5, 2003 and the period December 6, 2003 through December 31, 2003, were affected by an unrealized loss of $15.1 million and an unrealized gain of $2.0 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 year ended December 31, 2002, we reclassified gains of $0.9 million from OCI to current-period earnings. During the periods January 1, 2003 through December 5, 2003 and December 6, 2003 through December 31, 2003 losses of $29.7 and $0 million, respectively, were reclassified from OCI to current-period earnings. Our plan of reorganization became effective December 5, 2003 and, accordingly, we made adjustments for Fresh Start in accordance with SOP 90-7. These Fresh Start adjustments resulted in a write-off of net losses recorded in OCI of $65.9 million on interest rate swaps accounted for as hedges. We expect to reclassify an additional $0.7 million of deferred gains to earnings during the next twelve months on interest rate swaps accounted for as hedges.

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 years ended December 31, 2001, December 31, 2002 or during the periods January 1, 2003 through December 5, 2003 and December 6, 2003 through December 31, 2003.

Our pre-tax earnings for the years ended December 31, 2001 and 2002 were increased by an unrealized gain of $0.3 million and $0.3 million, respectively, associated with foreign currency hedging instruments not accounted for as hedges in accordance with SFAS No. 133.

Our pre-tax earnings for the period January 1, 2003 through December 5, 2003 and the period December 6, 2003 through December 31, 2003, were increased by an unrealized gain of $0.1 million and $0, respectively, associated with foreign currency hedging instruments not accounted for as hedges in accordance with SFAS No. 133.

During the year ended December 31, 2002, we reclassified losses of $2.1 million from OCI to current period earnings. During the periods January 1, 2003 through December 5, 2003 and December 6, 2003 through December 31, 2003 losses of $0 and $0 million, respectively, were reclassified from OCI to current-period earnings. Our plan of reorganization became effective December 5, 2003 and, accordingly, we made adjustments for Fresh Start in accordance with SOP 90-7. These Fresh Start adjustments resulted in a write-off of net losses recorded in OCI of $0.2 million on foreign currency swaps accounted for as hedges. We do not expect to reclassify any deferred gains or losses to earnings during the next twelve months on foreign currency swaps accounted for as hedges.

Note 17 — Debt and Capital Leases

Long-term debt and capital leases consist of the following:

	Predecessor Company			Reorganized NRG			
				Principal	Fair Value Adjustment	Principal	Fair Value Adjustment
			Principal	December 6,		December 31,	
	Stated Rate	Effective Rate	December 31, 2002	2003	2003	2003	2003
	(Percent)		(In thousands)				
NRG Recourse Debt:							
NRG New Credit Facility, due June 23, 2010	(2)	—	$ —	**$ —**	**$ —**	**$1,200,000**	**$ —**
NRG Energy Promissory Note, Xcel Energy, due June 5, 2006	3.00	9.00	—	**10,000**	**(1,349)**	**10,000**	**(1,310)**
NRG Energy ROARS, due March 15, 2020	7.97	—	257,552	**—**	**—**	**—**	**—**
NRG Energy senior debentures (corporate units), due May 16, 2006	6.50	—	285,728	**—**	**—**	**—**	**—**

	Predecessor Company			Reorganized NRG			
				Principal	Fair Value Adjustment	Principal	Fair Value Adjustment
			Principal	December 6,		December 31,	
	Stated Rate	Effective Rate	December 31, 2002	2003	2003	2003	2003
	(Percent)			(In thousands)			
NRG Energy senior notes:							
December 15, 2013	8.00	—	—	**1,250,000**			
February 1, 2006	7.625	—	125,000	—	—	—	—
July 15, 2006	6.75	—	340,000	—	—	—	—
June 15, 2007	7.50	—	250,000	—	—	—	—
June 1, 2009	7.50	—	300,000	—	—	—	—
September 15, 2010	8.25	—	350,000	—	—	—	—
April 1, 2011	7.75	—	350,000	—	—	—	—
November 1, 2003	8.00	—	240,000	—	—	—	—
April 1, 2031	8.625	—	340,000	—	—	—	—
April 1, 2031	8.625	—	160,000	—	—	—	—
NRG Project — Level, Non — Recourse Debt:							
NRG Finance Company I LLC — construction revolver, May 2006	(2)	—	1,081,000	—	—	—	—
NRG Processing Solutions, capital lease, due November 2004	9.00	A+2(3)	676	**355**	**12**	**326**	**10**
NRG Pike Energy LLC, due 2010		—	155,477	—	—	—	—
NRG Energy Center San Diego, LLC promissory note, due June 2003	8.00	—	278	—	—	—	—
NRG Energy Center Pittsburgh LLC, due November 2004	10.61	A+2(3)	3,050	**1,550**	**74**	**1,550**	**66**
NRG Energy Center San Francisco LLC, senior secured notes, due November 2004	10.61	A+2(3)	2,310	**860**	**45**	**860**	**41**
Meriden due May 14, 2003	10.00	—	—	**500**	—	**500**	—
LSP Kendall Energy LLC, due September 2005(1)(5)	2.65	A+3.5(4)	495,754	**489,198**	**(31,160)**	**487,013**	**(30,370)**
MidAtlantic Generating LLC, due October 2005(5)	4.625	—	409,201	**406,560**	—	—	—
Camas Power Boiler LP, unsecured term loan, due June 30, 2007	3.65	A+2(3)	10,896	**9,202**	**(286)**	**8,628**	**(277)**
COBEE, due July 2007(6)	(2)	15.00	42,150	**31,800**	**(3,028)**	**31,800**	**(2,815)**
Camas Power Boiler LP, revenue bonds, due August 1, 2007	3.38	A+2(3)	6,965	**5,765**	**(115)**	**5,765**	**(108)**
NRG Brazos Valley LLC, due June 30, 2008	6.75	—	194,362	—	—	—	—
Flinders Power Finance Pty, due September 2012, 6.14%-6.49%	(2)	6.00	99,175	**185,825**	**10,434**	**187,668**	**10,632**
Hsin Yu(6)	(2)	—	85,607	**84,980**	**(45,000)**	**85,300**	**(44,480)**
NRG Energy Center Minneapolis LLC senior secured notes due 2013 and 2017, 7.12%-7.31%	(2)	A+2(3)	133,099	**127,275**	**7,112**	**126,279**	**7,030**

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Predecessor Company			Reorganized NRG			
			Principal	Principal	Fair Value Adjustment	Principal	Fair Value Adjustment
	Stated Rate	Effective Rate	December 31, 2002	December 6, 2003	December 6, 2003	December 31, 2003	December 31, 2003
	(Percent)		(In thousands)				
LSP Energy LLC (Batesville), due 2014 and 2025, 7.16%-8.16%(6)	(2)	8.23- 9.31	314,300	**307,175**	**(12,528)**	**307,175**	**(12,292)**
PERC, due 2017 and 2018(6)	6.75	A+2(3)	28,695	**26,265**	**(1,228)**	**26,265**	**(1,203)**
Northbrook New York	4.10	4.42	—	**17,223**	**(319)**	**17,199**	**(315)**
Northbrook Carolina	5.10	6.42	—	**2,500**	**(178)**	**2,475**	**(177)**
Northbrook STS HydroPower	9.13	9.70	—	**24,374**	**(927)**	**24,506**	**(930)**
Saale Energie GmbH, Schkopau Capital lease, due 2021	(2)	—	325,583	**318,025**	**—**	**342,469**	**—**
Audrain County, MO — Capital lease, due December 2023	10.00	—	239,930	**239,930**	**—**	**239,930**	**—**
NRG South Central Generating LLC senior bonds, due various dates through September 15, 2024(5)	(2)	—	750,750	**750,750**	**—**	**—**	**—**
NRG Northeast Generating LLC senior bonds, due various dates through December 15, 2024(5)	(2)	—	556,500	**556,500**	**—**	**—**	**—**
NRG Peaker Finance Co. LLC(1)(5)		A+3.5(4)	319,362	**319,362**	**(72,657)**	**311,373**	**(72,105)**
Subtotal			8,253,400	**3,915,974**	**(151,098)**	**4,667,081**	**(148,603)**
Less discontinued operations			470,752	**450,220**	**(61,784)**	**450,540**	**(61,073)**
Less current maturities			7,001,134	**2,598,288**	**(101,534)**	**901,242**	**(100,013)**
Total			$ 781,514	**$ 867,466**	**$ 12,220**	**$3,315,299**	**$ 12,483**

(1) We have reclassified the long-term portions of these debt issuances to current as they were callable within one year from December 31, 2003.

(2) Distinguishes debt with various interest rates.

(3) A+2 equals Libor plus 2%

(4) A+3.5 equals Libor plus 3.5%

(5) We have reclassified the long-term portions of these debt issuances to current, as they were callable within one year from December 6, 2003.

(6) Discontinued operations

As of December 31, 2003, we have timely made 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. However, a significant amount of our subsidiaries' debt and other obligations contain terms that require that they be supported with letters of credit or cash collateral following a ratings downgrade or a default on our debt. As of December 31, 2003, as a result of the downgrades and loan defaults that we experienced in 2002, we estimate that we were in default of our obligations to post collateral of approximately $71.4 million, principally to fund contract termination penalties, revenue shortfall guarantees and late completion penalties related to NRG Peaker Finance Company LLC. On January 6, 2004, the debt held at NRG Peaker Finance Company LLC was restructured, and this collateral obligation ceased. As a result, we currently have no unmet cash collateral obligations outstanding.

Short Term Debt

On December 23, 2003, we entered into a bank facility for up to $1.45 billion, or “New Credit Facility”, which included a $950.0 million, six and a half-year senior secured term loan, a $250.0 million funded letter of credit facility, and a four-year $250.0 million revolving line of credit, or “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 December 31, 2003, the corporate revolver was undrawn. The $250 million funded letter of credit is reflected as a funded deposit on the December 31, 2003 balance sheet.

Long-term Debt and Capital Leases

Senior Securities

As a result of our bankruptcy filing, we ceased recording accrued interest on the following unsecured facilities, as it was not probable of being paid. On December 5, 2003, concurrent with our emergence from bankruptcy, the following senior unsecured facilities were terminated in conjunction with certain settlement provisions. We have no outstanding obligations with respect to the following terminated debt facilities:

- NRG Energy ROARS, due March 15, 2020, 7.97%; $250.0 million in outstanding principal, $25.3 million in accrued interest, and $41.1 million in contractually obligated interest at date of termination;
- NRG Energy senior debentures, or “corporate units”, due May 16, 2006, 6.5%; $287.5 million in outstanding principal, $14.2 million in accrued interest, and $26.5 million in contractually obligated interest at date of termination;
- NRG Energy senior notes due February 1, 2006, 7.625%; $125.0 million in outstanding principal, $7.7 million in accrued interest, and $14.2 million in contractually obligated interest at date of termination;
- NRG Energy senior notes due July 15, 2006, 6.75%; $340.0 million in outstanding principal, $21.9 million in accrued interest, and $34.9 million in contractually obligated interest at date of termination;
- NRG Energy senior notes due June 15, 2007, 7.50%; $250.0 million in outstanding principal, $19.4 million in accrued interest, and $30.7 million in contractually obligated interest at date of termination;
- NRG Energy senior notes due June 1, 2009, 7.50%; $300.0 million in outstanding principal, $20.4 million in accrued interest, and $37.9 million in contractually obligated interest at date of termination;
- NRG Energy senior notes due September 15, 2010, 8.25%; $350.0 million in outstanding principal, $34.5 million in accrued interest, and $56.9 million in contractually obligated interest at date of termination;
- NRG Energy senior notes, due April 1, 2011, 7.75%; $350.0 million in outstanding principal, $31.2 million in accrued interest, and $51.5 million in contractually obligated interest at date of termination;

- NRG Energy senior notes, due November 1, 2003, 8.00%; $240.0 million in outstanding principal, $17.5 million in accrued interest, and $34.6 million in contractually obligated interest at date of termination;

- NRG Energy senior notes, due April 1, 2031, 8.625%; $340.0 million and $160 million in outstanding principal, and $49.7 million in accrued interest, and $83.0 million in contractually obligated interest at date of termination; and

- NRG Energy corporate revolver, due March 8, 2003; $930.5 million in outstanding principal, $57.7 million in accrued interest, and $84.8 million in contractually obligated interest at date of termination.

As part of and concurrent with the emergence from bankruptcy, certain unsecured creditors received rights to $500.0 million of 10% NRG Energy senior notes, or "POR Notes" to be issued by us. However, the creditors accepted $500 million in cash in lieu of the POR Notes, on December 23, 2003 in conjunction with the financing described below. Accrued interest of $2.5 million was paid to these creditors based on the notional amount of the POR Notes. As of December 31, 2003, there were no outstanding obligations with respect to the POR Notes.

On December 23, 2003, we issued $1.25 billion in 8% Second Priority Notes, due and payable on December 15, 2013. The Second Priority Notes are general obligations of ours. They are secured on a second-priority basis by security interests in all assets of ours,

with certain exceptions, subject to the liens securing our obligations under the New Credit Agreement (described below) and any other priority lien debt. The notes are effectively subordinated to our obligations under the New Credit Facility and any other priority lien obligation, which will be secured on a first-priority basis by the same assets that secure the Second Priority Notes. The Second Priority Notes will be senior in right of payment to any future subordinated indebtedness. Interest on the Second Priority Notes accrues at the rate of 8.0% per annum and will be payable semi-annually in arrears on June 15 and December 15, commencing on June 15, 2004.

Also on December 23, 2003, concurrently with the offering of the notes, we and PMI entered into the New Credit Facility for up to $1.45 billion with Credit Suisse First Boston, as Administrative Agent, and Lehman Commercial Paper, Inc., as Syndication Agent and a group of lenders. The New Credit Facility consists of a $950 million, six and a half-year senior secured term loan facility, a $250 million, funded letter of credit facility, and a four-year revolving credit facility in an amount of up to $250 million. Portions of the revolving credit facility are available as a swing-line facility and as a revolving letter of credit sub-facility. No borrowings had been made under the revolving credit facility as of December 31, 2003. Under the letter of credit facility, $1.7 million had been issued as of December 31, 2003.

The New Credit Facility is secured by, among other things, first-priority perfected security interests in all of the property and assets owned at any time or acquired by us and our subsidiaries, other than the property and assets of certain excluded project subsidiaries, foreign subsidiaries and certain other subsidiaries, with some exceptions.

Interest on the New Credit Facility consists of a spread of either 3% over prime or 4% over a LIBO rate, to be selected by the borrower. Other expenses associated with the New Credit Facility include commitment fees on the undrawn portion of the letter of credit facility, participation fees for the credit-linked deposit and other fees. As of December 31, 2003, we did not have an interest rate swap in place to hedge against fluctuations in prime or LIBO rates. On February 25, 2004 we amended the new credit facility to remove this requirement.

Proceeds of the December 23, 2003 Second Priority Notes issuance and the New Credit Facility were used for the following purposes:

- Repayment of secured debt held by NRG Northeast Generating LLC, including $556.5 million in outstanding principal, $1.1 million in accrued interest, and $8.3 million in a make-whole premium;

- Repayment of secured debt held by NRG South Central Generating LLC, including $750.8 million in outstanding principal, $18.7 million in accrued interest, and $11.3 million in a make-whole premium;

- Repayment of secured debt held by NRG Mid-Atlantic Generating LLC, including $406.6 million in outstanding principal and $4.1 million in accrued interest;

- Funding of the $250 million letter of credit facility under the New Credit Facility;

- Payment of cash in lieu of the $500 million, 10% POR Notes to be issued to certain unsecured creditors; and

- Additional fees and expenses related to the transactions.

Significant affirmative covenants of the Second Priority Notes and the New Credit Facility include the provision of financial reports, reports of any events of default or developments that could have a material adverse effect, provision of notice with respect to changes in corporate structure or collateral. In addition, the borrower must maintain segregated cash accounts for certain deposits or settlements. A provision that the borrower enter into an interest-rate swap agreement on a portion of the term loan was waived by the lenders pursuant to an amendment to the New Credit Agreement.

Significant negative covenants of the Second Priority Notes and the New Credit Facility include limitations on permitted indebtedness, including the provision of intercompany loans among certain subsidiaries and affiliates; permitted liens; permitted acquisitions and certain asset dispositions. In addition, certain financial ratio tests must be met.

Events of default under the Second Priority Notes and the New Credit Facility include materially false representation or warranty; payment default on principal or interest; covenant defaults; cross-defaults to material indebtedness; our or a material subsidiary's bankruptcy and insolvency; material unpaid judgments; ERISA events; failure to be perfected on any material collateral; and a change in control.

On January 28, 2004, we issued an additional $475.0 million in Second Priority Notes, under the same terms and indenture as our December 23, 2003 offering. Proceeds of the offering were used to prepay $503.5 million of the outstanding principal on the term loan under the New Credit Facility, described below, reducing the outstanding principal of the term loan from $950.0 million to $446.5 million.

Project Financings

For discussion of NRG FinCo, the Audrain capital lease and LSP Pike Energy LLC see Note 24.

The LSP Kendall Energy LLC credit facility is non-recourse to us and consists of a construction and term loan, working capital and letter of credit facilities. As of December 31, 2002, December 6, 2003 and December 31, 2003, there were borrowings totaling approximately $495.8 million, $489.2 million and $487.0 million, respectively, outstanding under the facility at a weighted average annual interest rate of 3.15%, 2.58% and 2.58%, respectively. In May 2002, LSP-Kendall Energy, LLC received a notice of default from Societe Generale, the administrative agent under LSP-Kendall's Credit and Reimbursement Agreement dated November 12, 1999. The notice asserted that an event of default had occurred under the Credit and Reimbursement Agreement as a result of liens filed against the Kendall project by various subcontractors. In consideration of the borrower's implementation of a plan to remove the liens, and our indemnification pursuant to an Indemnity Agreement dated June 28, 2002, of the lenders to the Kendall project from any claims or damages relating to these liens or any dispute or action involving the project's EPC contractor, the administrative agent, with the consent of the required lenders under the Credit and Reimbursement Agreement, withdrew the notice of default and conditionally waived any default or event of default described therein. Discussions with the administrative agent regarding the liens continue. On August 25, 2003, LSP-Kendall Energy LLC entered into a Completion Extension and Amendment Agreement with the lenders and Societe Generale whereby certain extensions were granted in respect of project construction, lien removal and other items. The Completion Extension and Amendment Agreement prohibits LSP-Kendall Energy LLC from making any distributions to equity owners until January 1, 2005, and thereafter only when certain conditions are met. LSP-Kendall Energy LLC continues to be in default with respect to certain covenants, however, and is in discussions with the lenders regarding restructuring its indebtedness.

In May 1999, LSP Energy Limited Partnership, or "Partnership" and LSP Batesville Funding Corporation, or "Funding" issued two series of Senior Secured Bonds, or "Bonds" in the following total principal amounts: $150 million 7.16% Series A Senior Secured Bonds due 2014 and $176 million 8.160% Series B Senior Secured Bonds due 2025. Interest is payable semiannually on each January 15 and July 15. In March 2000, a registration statement was filed by Partnership and Funding and became effective. The registration statement was filed to allow the exchange of the Bonds for two series of debt securities, or "Exchange Bonds", which are in all material respects substantially identical to the Bonds. The Exchange Bonds are secured by substantially all of the personal property and contract rights of the Partnership and Funding. The Exchange Bonds are redeemable, at the option of Partnership and Funding, at any time in whole or from time to time in part, on not less than 30 nor more than 60 days prior notice to the holders of that series of Exchange Bonds, on any date prior to their maturity at a redemption price equal to 100% of the outstanding principal amount of the Exchange Bonds being redeemed and a make whole premium. In no event will the redemption price ever be less than 100% of the principal amount of the Exchange Bonds being redeemed plus accrued and unpaid interest thereon. Principal payments are payable on each January 15 and July 15 beginning July 15, 2001. Under the credit arrangements, the project is required to maintain minimum cash balances in certain reserve funds. Subject to funding these reserve accounts and anticipated working capital needs, and meeting certain debt coverage tests, the project may distribute any remaining cash to us. As of December 31, 2003, Batesville had sufficiently funded its reserve accounts, but did not meet its debt coverage test.

In June 2002, NRG Peaker Finance Company LLC, or "NRG Peaker", an indirect wholly owned subsidiary, completed the issuance of $325 million of Series A Floating Rate Senior Secured Bonds due 2019. The bonds bear interest at a floating rate equal to three-month LIBOR 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. NRG Peaker subsequently entered into an interest rate swap agreement pursuant to which it agreed to make 6.67% fixed rate interest payments and receive floating rate interest payments. XL Capital Assurance, or "XLCA", guarantees principal, interest and swap payments, through a financial guaranty insurance policy. Such notes are also secured by substantially all of the assets of and/or membership interests in our subsidiaries: Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Sterlington Power LLC, NRG Rockford LLC, NRG Rockford II LLC and NRG Rockford Equipment LLC. As of December 31, 2003, $311.4 million in aggregate principal remained outstanding on these bonds. XLCA accelerated the bonds due to cross-defaults on our debt and liens placed upon certain assets. On January 6, 2004, we and XLCA consummated a comprehensive restructuring arrangement which provides for, among other things, the provision of a letter of credit by us for the benefit of the secured parties in the NRG Peaker financing, 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.

In May 2001, our wholly-owned subsidiary, NRG Finance Company I LLC, or "NRG FinCo", entered into a $2.0 billion revolving credit facility. The facility was established to finance the acquisition, development and construction of power generating plants located in the United States and to finance the acquisition of turbines for such facilities. The facility provided for borrowings of base rate loans and Eurocurrency loans and was secured by mortgages and security agreements in respect of the assets of the projects financed under the facility, pledges of the equity interests in the subsidiaries or affiliates of the borrower that own such projects, and by guaranties from each such subsidiary or affiliate. The NRG FinCo secured revolver was initially scheduled to mature on May 8, 2006; however, due to defaults hereunder by NRG FinCo and applicable guarantors, the lenders accelerated all outstanding obligations on November 6, 2002. As of our emergence, $1.1 billion was outstanding under the facility, and there was an aggregate of approximately $58 million of accrued but unpaid interest and commitment fees. Of this, $842.0 million was allowed in unsecured claims under NRG plan of reorganization, and was settled at the time of our emergence. The remaining balance will be satisfied when the NRG FinCo lenders exercise their perfected security interests in our Nelson, Audrain and Pike projects (see note 24).

Meriden Gas Turbines LLC, or “MGT” is party to a $0.5 million Promissory Note and Security Agreement with PowerSource LLC, issued and entered into on February 13, 2003. MGT used the proceeds of the note issuance to allow the release of a lien and claim on certain MGT assets, and for costs associated with the transport of certain equipment to the MGT site. The note became due and payable on May 14, 2003. We expect to repay this note with the proceeds from the sale of the MGT assets in 2004.

In March 2001, we increased our ownership interest in Penobscot Energy Recovery Company, or “PERC”, which resulted in the consolidation of our equity investment in PERC. As a result, the assets and liabilities of PERC became part of our consolidated assets and liabilities. Upon completion of the transaction, we recorded approximately $37.9 million of outstanding Finance Authority of Maine Electric, or “FAME” Rate Stabilization Revenue Refunding Bonds Series 1998, or “FAME bonds” which were issued on PERC’s behalf by FAME in June 1998. The face amount of the bonds that were initially issued was approximately $44.9 million and was used to repay the Floating Rate Demand Resource Revenue Bonds issued by the Town of Orrington, Maine on behalf of PERC. The FAME bonds are fixed rate bonds with yields ranging from 3.75% to 5.2%. The weighted average yield on the FAME bonds is approximately 5.1%. The FAME bonds are subject to mandatory redemption in annual installments of varying amounts through July 1, 2018. Beginning July 1, 2008 the FAME bonds are subject to redemption at the option of PERC at a redemption price equal to 102% through June 30, 2009, 101% for the period July 1, 2009 to June 30, 2010 and 100% thereafter, of the principal amount outstanding, plus accrued interest. The loan agreement with FAME contains certain restrictive covenants relating to the FAME bonds, which restrict PERC’s ability to incur additional indebtedness, and restricts the ability of the general partners to sell, assign or transfer their general partner interests. The bonds are collateralized by liens on substantially all of PERC’s assets. As of December 31, 2003, $26.3 million in principal remains outstanding.

In November 2001, NRG McClain LLC entered into a $181.0 million term loan and $8.0 million working capital facility with Westdeutsche Landesbank Girozentrale, New York branch, as agent to repay an outstanding term loan used to finance the acquisition of the McClain generating facility (non-recourse to us). The final maturity date of the facility is November 30, 2006. As of December 31, 2002 and 2003, the aggregate amount outstanding under this facility was $157.3 million and $156.5 million, respectively. During the period ended December 31, 2002 and 2003, the weighted average interest rate of such outstanding borrowings was 4.51% and 5.89%, respectively. On September 17, 2002, NRG McClain LLC 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 and Electric Company for substantially all of the assets of McClain and contemporaneously filed for bankruptcy pursuant to the asset purchase agreement. Upon consummation of the asset sale we anticipate that all proceeds from the sale will be used to repay outstanding project debt under the secured term loan and working capital facility. On December 18, 2003, FERC issued an order setting the application for hearing to determine remedies FERC could impose as a condition of any approval for the transaction. This sale will not be completed until FERC approval is received. NRG McClain is recorded as a discontinued operation in the accompanying balance sheets.

The Camas Power Boiler LP notes are secured principally by its long-term assets. In accordance with the terms of the note agreements, Camas Power Boiler LP is required to maintain compliance with certain financial covenants primarily related to incurring debt, disposing of assets, and affiliate transactions. Camas Power Boiler was in compliance with these covenants at December 31, 2003. Distributions to us from Camas are permitted quarterly, contingent upon the project sufficiently funding debt service accounts, and meeting certain covenants and conditions. As of December 31, 2003, Camas met all requirements for distributions.

In July 2002, NRG Energy Center Minneapolis LLC, or “MEC”, an indirect wholly owned subsidiary, entered into an agreement allowing it to issue senior secured promissory notes in the aggregate principal amount of up to $150 million. In July 2002, under this agreement, MEC issued $75 million of bonds in a private placement. Two series of notes were issued in July 2002, the $55 million Series A-Notes dated July 3, 2002, which matures on August 1, 2017 and bears an interest rate of 7.25% per annum and the $20 million Series B-Notes dated July 3, 2002, which matures on August 1, 2017 and bears an interest rate of 7.12% per annum. NRG Thermal LLC, a directly held, wholly-owned subsidiary, which owns 100% of MEC, pledged its interests in all of its district heating and cooling investments throughout the United States as collateral. NRG Thermal and MEC are required to maintain compliance with certain financial covenants primarily related to incurring debt, disposing of assets, and affiliate transactions. In August 1993, MEC issued $84 million of 7.31% senior secured notes, due June 15, 2013. The three MEC notes contain a covenant providing the lender the option to choose prepayment of the notes if, among other things, Xcel Energy no longer directly or indirectly owns a controlling interest in NRG Thermal. Xcel Energy no longer owns a controlling interest in NRG Thermal as a result of our emergence from bankruptcy. In anticipation of the change in control, NRG Thermal has entered into a forbearance agreement with the lender to allow time to negotiate a modified loan covenant package that would enable the lender to choose not to exercise its change in control option. Until a new loan covenant package has been developed, terms of the forbearance agreement prevent MEC or its subsidiaries from making distributions to us. The forbearance agreement expires June 1, 2004. As a result of the forbearance agreement, NRG Thermal and MEC were in compliance with their credit covenants at December 31, 2003.

STS Hydropower, LTD, or “STS Hydropower” which is indirectly 50% owned by NEO Corporation, or “NEO”, our wholly-owned subsidiary, entered into a Note Purchase Agreement in March 1995 with Allstate Life Insurance Co., or “Allstate”. Allstate purchased from STS Hydropower $22.1 million of 9.155% senior secured debt due December 30, 2016. The agreement was amended in 1996 to add $0.7 million of 8.24% senior secured debt due March 2011. The debt is secured by substantially all assets of and interest in STS Hydropower. Because of poor hydroelectric output due to drought conditions, no principal or interest payments have been made on this loan facility since October 2001. In May 2003, the facility was restructured and currently has a maturity of March 2023 and an interest rate of 9.133%. As of December 31, 2003, all required covenants under the restructured facility had been met and $25.2 million of principal was outstanding.

In September 1999, Northbrook New York LLC, or “NNY”, which is indirectly owned by NEO, entered into a $17.5 million term loan agreement with Heller Financial. In December 2001, the credit agreement with Heller Financial was amended to include $2.6 million of financing for Northbrook Carolina Hydro, LLC, or “NCH”, which is indirectly 50% owned by NEO, and to cross-collateralize the NNY and NCH notes. Heller Financial was subsequently purchased by GE Capital Services, which assumed the notes. The loan facilities are secured by substantially all hydroelectric assets of and membership interests in NCH and NNY. The NNY facility bears an interest rate of LIBOR plus 3% and matures in December 2018. The NCH facility bears interest at an interest rate of LIBOR plus 4% and matures in December 2016. As of December 31, 2003, the outstanding principal balance on the NNY facility and the NCH facility was

$17.2 million and $2.5 million, respectively. On December 2001, NCH purchased a $0.3 million subordinated note from NEO. This subordinated note accrues interest at 11% per annum, and no payment is due until maturity on December 31, 2018.

In September 2000, Flinders Power Finance Pty Ltd, or “Flinders Power”, an Australian wholly owned subsidiary, entered into a twelve year AUD $150 million cash advance facility (US $81.4 million at September 2000). As of December 31, 2002 and 2003, there remains AUD$143.4 million (US$80.5 million) and AUD$135.0 million (US$101.6 million) outstanding under this facility, respectively. The interest has fixed and variable components. At December 31, 2002 and 2003, the interest rate was 6.49% and 7.53%, respectively and is paid semi-annually. Principal payments commence in 2006 and the facility will be fully paid in 2012.

In March 2002, Flinders Power entered into a 10 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. As of December 31, 2002 and 2003, the Company had drawn AUD$33.3 million (US$18.7 million) and AUD$114.3 million (US$86.0 million), respectively, of this facility. The interest rate has fixed and variable components. The interest rate at December 31, 2002 and 2003 was 6.14% and 7.03%, and is paid semi-annually. Principal payments for the refurbishment facility commence in 2005. Upon our downgrades in 2002, there existed a potential default under these facility agreements related to the funding of reserve accounts. On May 13, 2003, Flinders Power 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 Power so as to reduce the total available commitment from AUD$165 million to AUD$137 million (US$103.1 million).

In connection with our acquisition of a controlling interest in the COBEE facilities, we assumed non-recourse long-term debt that is due in 18 semi-annual installments of varying amounts beginning January 31, 1999 and ending July 31, 2007. The loan agreement provides an A Loan of up to $30 million and a B Loan of up to $45 million. The balance of the A and B loans was $31.8 million as of December 31, 2003. Interest is payable semi-annually in arrears at a rate equal to 6-month LIBOR plus a margin of 4.5% on the A Loan and 6-month LIBOR plus a margin of 4.0% on the B Loan. The A Loan and the B Loan are collateralized by a mortgage on substantially all of COBEE’s assets.

In connection with our purchase of PowerGen’s interest in Saale Energie GmbH, we have recognized a non-recourse capital lease on our balance sheet in the amount of $325.6 million and $342.5 million, as of December 31, 2002 and 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 $366.4 million, $435.0 million and $451.4 million, as of December 31, 2002, December 6, 2003 and December 31, 2003, respectively.

Hsin Yu, which is approximately 63% indirectly owned by us, entered into a NT$2,700.0 million syndicated loan arrangement to finance construction of what was to be the first phase of a multi-phase cogeneration facility. Chiao Tung Bank led the original financing. Principal covenants of the syndicated facility include maintaining a debt to equity ratio below 250% until 2006, and a ratio below 200% thereafter, and maintaining a debt service coverage ratio above 1.1, starting in 2004. The fair value adjustment reflects the uncertainty of repayment of such obligations from project cash flows.

Annual maturities of long-term debt and capital leases for the years ending after December 31, 2003 are as follows:

	Discontinued Operations	Continuing Operations	Total
		(In thousands)	
2004	$ 105,635	$ 901,242	$1,006,877
2005	22,955	112,684	135,639
2006	18,455	92,034	110,489
2007	19,150	72,074	91,224
2008	14,935	65,159	80,094
Thereafter	269,410	2,973,348	3,242,758
Total	$ 450,540	$4,216,541	$4,667,081

Future minimum lease payments for capital leases included above at December 31, 2003 are as follows:

	(In thousands)
2004	$ 125,020
2005	127,608
2006	89,875
2007	76,647
2008	68,940
Thereafter	689,165
Total minimum obligations	1,177,255
Interest	594,519
Present value of minimum obligations	582,736
Current portion	76,280
Long-term obligations	$ 506,456

Assets related to our capital leases were revalued as of December 6, 2003, to $171.0 million and remained at $171.0 million with no accumulated amortization at December 31, 2003, as the amounts have been recorded at recoverable values. Total net book value related to these assets at December 31, 2002 was $258.2 million, net of $2.3 million of accumulated amortization.

Note 18 — Capital Stock

Reorganized Capital Structure

In connection with the consummation of our plan of reorganization, on December 5, 2003 all shares of our old common stock were canceled and 100,000,000 shares of new common stock of NRG Energy were distributed pursuant to such plan to the holders of certain classes of claims. A certain number of shares of common stock were issued for distribution to holders of disputed claims as such claims are resolved or settled. In the event our disputed claims reserve is inadequate, it is possible we would have to issue additional shares of our common stock to satisfy such pre-petition claims or contribute additional cash proceeds. See Note 24 — Disputed Claims Reserve. Our authorized capital stock consists of 500,000,000 shares of NRG Energy common stock and 10,000,000 shares of Serial Preferred Stock. Further, a total of 4,000,000 shares of our common stock, representing approximately 4% of our outstanding common stock, are available for issuance under our long-term incentive plan.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

In addition to our issuance of new common stock, on December 23, 2003, we completed a note offering consisting of $1.25 billion of 8% Second Priority Senior Secured Notes due 2013, and we entered into a new credit facility consisting of a $950.0 term loan facility, a $250.0 million funded letter of credit facility and a $250 million revolving credit facility. We used the proceeds of these offerings to retire certain project level debt, pay certain unsecured creditors and relieve associated cash traps. In January of 2004, we completed a supplementary note offering whereby we issued an additional $475 million of 8% Second Priority Senior Secured Notes due 2013 at a premium and used the proceeds there from to repay a portion of the $950.0 million term loan. As of March 1, 2004, the outstanding principal balance on the notes was $1.725 billion, the principal amount outstanding under the term loan was $446.5 million and $147.5 million remains available under the funded letter of credit facility. As of March 1, 2004, we had not drawn down on our revolving credit facility. Finally, in connection with the consummation of our plan of reorganization, we issued to Xcel Energy a $10.0 million non-amortizing promissory note, which will accrue interest at a rate of 3% per annum and mature 2.5 years after the effective date of our plan of reorganization.

As part of our plan of reorganization, we eliminated approximately $5.2 billion of corporate level bank and bond debt and approximately $1.3 billion of additional claims and disputes through our distribution of new common stock and $1.04 billion in cash among our unsecured creditors. In addition to the debt reduction associated with the restructuring, we used the proceeds of the recent note offering and borrowings under the New Credit Facility to retire approximately $1.7 billion of project-level debt.

For additional information on our short term and long term borrowing arrangements, see Note 17.

Sale of Stock

In June 2000, we sold 32.4 million shares of common stock at $15 per share. Net proceeds from the offering were $453.7 million. At that time we were authorized to issue capital stock consisting of 550,000,000 shares of common stock, and 250,000,000 shares of Class A common stock. At December 31, 2000, there were approximately 32,396,000 shares of common stock, and 147,605,000 shares of Class A common stock issued and outstanding.

In March 2001, we completed the sale of 18.4 million shares of common stock for an initial price of $27 per share. The offering was completed with all 18.4 million shares of common stock being sold including the over-allotment shares of 2.4 million. We received gross proceeds from the issuance of $496.6 million. Net proceeds from the issuance were $473.4 million after deducting underwriting discounts, commissions and estimated offering expenses. The net proceeds were used in part to reduce amounts outstanding under our short-term bridge credit agreement, which was used to finance, in part, our acquisition of the LS Power assets.

At December 31, 2001, there were approximately 50,939,875 shares of common stock, and 147,605,000 shares of Class A common stock issued and outstanding.

On June 3, 2002, Xcel Energy completed its exchange offer for the 26% of our common shares that had been previously publicly held. Xcel Energy issued to our shareholders 0.50 shares of Xcel Energy common stock in exchange for each outstanding share of our common stock.

Incentive Compensation Plans

In June 2000, we adopted an incentive compensation plan, or “the Stock Plan”, which was approved by shareholders in June 2001. We accounted for this plan under the recognition and measurement provisions of APB Opinion No. 25, *“Accounting for Stock Issued to Employees,”* and related Interpretations. During 2002, the Stock Plan, and all grants under the plan, were adopted by the Xcel Energy Incentive Stock Plan. There were no grants to our employees under the Xcel Energy Incentive Stock Plan. During 2001, we recognized approximately $1.9 million of stock based compensation expense under the New Stock Plan. In 2002, we recognized income due to the net reduction of our compensation expense accrual by approximately

$2.3 million for terminated stock options during the period. The amount was reported as a reduction of compensation expense for the year ended December 31, 2002.

Effective January 1, 2003, we adopted the fair value recognition provisions of SFAS Statement No. 123, *“Accounting for Stock-Based Compensation”* or “SFAS No. 123.” In accordance with SFAS Statement No. 148, *“Accounting for Stock-Based Compensation — Transition and Disclosure”* or “SFAS No. 148”, we adopted SFAS No. 123 under the prospective transition method which requires the application of the recognition provisions to all employee awards granted, modified, or settled after the beginning of the fiscal year in which the recognition provisions are first applied. As a result, we recognized compensation expense for any grants issued on or after January 1, 2003. There were no grants issued during the period from January 1, 2003 through December 4, 2003.

During 2003, we recognized approximately $540,000 of stock based compensation expense under the Long-Term Incentive Plan, approximately $424,000 related to stock options and approximately $116,000 related to restricted stock. In December 2003, we adopted a new long-term incentive plan, or “the Long-Term Incentive Plan”, which is described below.

Long-Term Incentive Plan

The Long-Term Incentive Plan became effective upon our emergence from bankruptcy. The long-term incentive plan provides for grants of stock options, stock appreciation rights, restricted stock, performance awards, deferred stock units and dividend equivalent rights. Our directors, officers and employees, as well as other individuals performing services for, or to whom an offer of employment has been extended by us, are eligible to receive grants under the long-term incentive plan. The purpose of the long-term inventive plan is to promote our long-term growth and profitability by providing these individuals with incentives to maximize stockholder value and otherwise contribute to our success and to enable us to attract, retain and reward the best available persons for positions of responsibility.

A total of 4,000,000 shares of our common stock, representing approximately 4% of our outstanding common stock, are available for issuance under the long-term incentive plan, subject to adjustment in the event of a reorganization, recapitalization, stock split, reverse stock split, stock dividend, combination of shares, merger or similar change in our structure or our outstanding shares of common stock.

The compensation committee of our board of directors will administer the long-term incentive plan. If for any reason a compensation committee has not been appointed by our board to administer the long-term incentive plan, our board of directors will have the authority to administer the plan and to take all actions under the plan.

The following is a summary of the material terms of the long-term incentive plan, but does not include all of the provisions of the plan.

Eligibility. Our directors, officers and employees, as well as other individuals performing services for, or to whom an offer of employment has been extended by, us are eligible to receive grants under the long-term incentive plan. In each case, the compensation committee will select the actual grantees.

Stock Options. Under the long-term incentive plan, the compensation committee may award grants of incentive stock options conforming to the requirements of Section 422 of the Internal Revenue Code or non-qualified stock options. The compensation committee may not award to any one person in any calendar year options to purchase more than 1,000,000 shares of common stock. In addition, it may not award incentive stock options first exercisable in any calendar year whose underlying shares have a fair market value greater than $100,000, determined at the time of grant.

The compensation committee will determine the exercise price of any options granted under the long-term incentive plan. However, the exercise price of any option may not be less than 100% of the fair market value of a share of our common stock on the date of grant, and the exercise price of an incentive stock option granted to a person who owns stock constituting more than 10% of the voting power of all classes of our stock may not be less than 110% of the fair market value of a share of our common stock on the date of grant.

Unless the compensation committee determines otherwise, the exercise price of any option may be paid in any of the following ways:

• in cash;

• by delivery of shares of common stock with a fair market value equal to the exercise price;

• by means of any cashless exercise procedure approved by the compensation committee; or

• by any combination of the foregoing.

The compensation committee will determine the term of each option in its discretion. However, no term may exceed 10 years from the date of grant or, in the case of an incentive stock option granted to a person who owns stock constituting more than 10% of the voting power of all classes of our stock, five years from the date of grant. In addition, all options under the long-term incentive plan, whether or not then exercisable, generally will cease vesting when a grantee ceases to be a director, officer or employee of, or to otherwise perform services for, us. Vested options will generally expire 90 days after the date of cessation of service.

There will be exceptions depending upon the circumstances of cessation. In the case of a grantee's death, all options will become fully vested and will remain exercisable for a period of one year after the date of death. In the case of a grantee's termination due to disability, vested options will remain exercisable for a period of one year after the date of termination due to disability while his or her unvested options will be forfeited. In the event of retirement, a grantee's vested options will remain exercisable for a period of two years after the date of retirement while his or her unvested options will be forfeited. Upon termination for cause, all options will terminate immediately. Upon a change in control of NRG Energy, all of the options will become fully vested and will remain exercisable until the expiration date of the options. In addition, the compensation committee will have the authority to grant options that will become fully vested and exercisable automatically upon a change in control, whether or not the grantee is subsequently terminated.

Upon a reorganization, merger, consolidation or sale or other disposition of all or substantially all of our assets, the compensation committee may cancel any or all outstanding options under the long-term incentive plan in exchange for payment of an amount equal to the portion of the consideration that would have been payable to the grantees in the transaction if their options had been fully exercised immediately prior to the transaction, less the exercise price that would have been payable, or if the exercise price is greater than the consideration that would have been payable in the transaction, then for no consideration or payment.

Stock Appreciation Rights. Under the long-term incentive plan, the compensation committee may grant stock appreciation rights, or SARs, alone or in tandem with options, subject to terms and conditions as the compensation committee may specify. SARs granted in tandem with options will become exercisable only when, to the extent and on the conditions that the related options are exercisable, and they will expire at the same time the related options expire. The exercise of an option will result in the immediate forfeiture of any related SAR to the extent the option is exercised, and the exercise of a SAR results in the immediate forfeiture of any related option to the extent the SAR is exercised.

Upon exercise of a SAR, the grantee will receive an amount in cash, shares of our common stock or our other securities equal to the difference between the fair market value of a share of common stock on the date of exercise and the exercise price of the SAR or, in the case of a SAR granted in tandem with options, of the option to which the SAR relates, multiplied by the number of shares as to which the SAR is exercised. Unless otherwise provided in the grantee's grant agreement, each SAR will be subject to the same termination and forfeiture provisions as the stock options described above.

Restricted Stock. Under the long-term incentive plan, the compensation committee may award restricted stock in the amounts that it determines in its discretion. Each grant of restricted stock will be evidenced by a grant agreement, which will specify the applicable restrictions on such shares and the duration of the restrictions (which will generally be at least six months). A grantee will be required to pay us at least the aggregate par value of any shares of restricted stock within ten days of the grant, unless the shares are treasury shares. Unless otherwise provided in the grantee's grant agreement, each unit or share of restricted stock will be subject to the same termination and forfeiture provisions as the stock options described above.

Performance Awards. Under the long-term incentive plan, the compensation committee may grant performance awards contingent upon achievement by the grantee, us or any of our divisions of specified performance criteria, such as return on equity, over a specified performance cycle, as determined by the compensation committee. Performance awards may include specific dollar-value target awards; performance units, the value of which will be determined by the compensation committee at the time of issuance; and/or performance shares, the value of which will be equal to the fair market value of common stock. The value of a performance award may be fixed or may fluctuate based on specified performance criteria. A performance award may be paid out in cash, shares of our common stock or our other securities.

A grantee must be a director, officer or employee of, or otherwise perform services for, us at the end of the performance cycle in order to be entitled to payment of a performance award issued in respect of such cycle, provided that unless otherwise provided in the grantee's grant agreement, each performance award will be subject to the same termination and forfeiture provisions as the stock options described above.

Deferred Stock Units. Under the long-term incentive plan, the compensation committee may grant deferred stock units from time to time in its discretion. A deferred stock unit will entitle the grantee to receive the fair market value of one share of common stock at the end of the deferral period, which will be no less than one year. The payment of the value of deferred stock units may be made by us in shares of our common stock, cash or both. If a grantee ceases to be a director, officer or employee of, or otherwise perform services for, us upon his or her death prior to the end of the deferral period, the grantee will receive payment of his or her deferred stock units which would have matured or been earned at the end of the deferral period as if the deferral period has ended as of the date of his or her death. In the event of a termination due to disability or retirement prior to the end of the deferral period, the grantee will receive payment of his or her deferred stock units at the end of the deferral period. If a grantee ceases to be a director, officer or employee of, or otherwise perform services for, us for any other reason, his or her unvested deferred stock units will immediately be forfeited. Upon a change in control in NRG Energy, a grantee will receive payment of his or her deferred stock units as if the deferral period has ended as of the date of the change in control.

Dividend Equivalent Rights. Under the long-term incentive plan, the compensation committee may grant a dividend equivalent right entitling the grantee to receive amounts equal to all or any portion of the dividends that would be paid on shares of our common stock covered by an award if those shares had been delivered to the grantee pursuant to the award, subject to terms and conditions as the committee may specify.

Vesting, Withholding Taxes and Transferability of All Awards. The terms and conditions of each award made under the long-term incentive plan, including vesting requirements, will be set forth consistent with the plan in a written agreement with the grantee. Except in limited circumstances and unless the compensation committee determines otherwise, no award under the long-term incentive plan may vest and become exercisable within six months of the date of grant.

Unless the compensation committee determines otherwise, a participant may elect to deliver shares of common stock, or to have us withhold shares of common stock otherwise issuable upon exercise of an option or a SAR or deliverable upon grant or vesting of restricted stock or the receipt of common stock, in order to satisfy our tax withholding obligations in connection with any exercise, grant or vesting.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Unless the compensation committee determines otherwise, no award made under the long-term incentive plan will be transferable other than by will or the laws of descent and distribution, and each option, SAR or performance award may be exercised only by the grantee or his or her executor, administrator, guardian or legal representative, or by a family member of the grantee if he or she has acquired the option, SAR or performance award by gift or qualified domestic relations order.

Amendment and Termination of the Long-Term Incentive Plan. The board of directors or the compensation committee may amend or terminate the long-term incentive plan in its discretion, except that no amendment will become effective without prior approval of our stockholders if approval is required by applicable law or regulations, including any NASDAQ or stock exchange listing requirements, if the amendment would remove a provision of the long-term incentive plan which, without giving effect to the amendment, is subject to shareholder approval or if the amendment would directly or indirectly increase the share limit of 4,000,000 shares. If not otherwise terminated, the long-term incentive plan will terminate on the tenth anniversary of the effective date of our plan of reorganization, which was December 5, 2003.

In December 2003, we issued one stock option grant for a total of 632,751 shares of common stock under the Long-Term Incentive Plan. These options have a three-year graded vesting schedule and become exercisable through the year 2006 at a price of $24.03. Total compensation expense under the stock option grant is approximately $8.3 million. Compensation expense for the year ended December 31, 2003 was approximately $0.4 million. Compensation expense for the years ended December 31, 2004, December 31, 2005 and December 31, 2006 will be approximately $4.9 million, $2.2 million and $0.8 million, respectively. At December 31, 2003, no employee stock options were exercisable. Stock option transactions were:

	Shares	Weighted-Average Exercise Price
Outstanding at January 1, 2003	—	$ —
Granted	632,751	24.03
Exercised	—	—
Canceled or expired	—	—
Outstanding at December 6, 2003	632,751	24.03
Exercisable December 6, 2003	—	—
Granted	—	—
Exercised	—	—
Canceled or expired	—	—
Outstanding at December 31, 2003	632,751	24.03
Exercisable December 31, 2003	—	$ —
Weighted-average fair value of options granted during the year		$ 13.17

The following table summarizes information about stock options outstanding at December 31, 2003:

	Options Outstanding			Options Exercisable	
Range of exercise prices	Total Outstanding	Weighted-Average Remaining Life (In Years)	Weighted-Average Exercise Price	Total Exercisable	Weighted-Average Exercise Price
$24.03	632,751	10.0	$ 24.03	—	$ —

The fair value of the stock option grant was estimated on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions used for grants in 2003.

	2003
Dividends per year	—
Expected volatility	35.70
Risk-free interest rate	4.24
Expected life (years)	10

In December 2003, we issued 173,394 restricted stock units under the Long-Term Incentive Plan. These units will fully vest in December 2006. Total compensation expense under the restricted stock grant is approximately $4.2 million. Compensation expense for the year ended December 31, 2003 was approximately $0.1 million. Compensation expense for the years ended December 31, 2004, December 31, 2005 and December 31, 2006 will be approximately $1.4 million, $1.4 million and $1.3 million, respectively. The weighted-average fair value of our restricted stock units for 2003 is $24.03.

Note 19 — 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 is computed in a manner consistent with that of basic earnings per share while giving effect to all potentially dilutive common shares that were outstanding during the period. The 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 share is shown in the following table:

	Reorganized NRG For the Period December 6 - December 31, 2003
	(In thousands, except per share data)
Basic earnings per share	
Numerator:	
Income from continuing operations	$ 11,405
Discontinued operations, net of tax	(380)
Net income	$ 11,025
Denominator:	
Weighted average number of common shares outstanding	100,000
Income from continuing operations	$ 0.11
Discontinued operations, net of tax	—
Net income	$ 0.11
Diluted earnings per share	
Numerator	
Income from continuing operations	$ 11,405
Discontinued operations, net of tax	(380)
Net income	$ 11,025
Denominator:	
Weighted average number of common shares outstanding	100,000
Incremental shares attributable to the assumed exercise of outstanding stock options (treasury stock method)	—
Incremental shares attributable to the issuance of unvested stock grants (treasury stock method)	60
Total dilutive shares	100,060
Income from continuing operations	$ 0.11
Discontinued operations, net of tax	—
Net income	$ 0.11

The options to purchase 632,751 shares of common stock at a price of $24.03 per share were not included in the computation because the options' exercise price was greater than the average market price of the common shares and therefore the effect would be anti-dilutive.

Note 20 — 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 retroactively 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.

	Reorganized NRG December 6, 2003 Through December 31, 2003 Wholesale Power Generation				
	Northeast	South Central	West Coast	Other North America	Australia
			(In thousands)		
Operations					
Operating Revenues	$ 69,191	$ 26,609	$ (268)	$ 5,377	$ 11,947
Depreciation and amortization	4,604	2,561	58	1,639	1,475
Reorganization items	241	27	—	—	—
Operating Income/(Loss)	11,330	4,530	(445)	948	87
Minority interest in earnings of consolidated subsidiaries	—	—	—	(134)	—
Equity in earnings of unconsolidated affiliates	—	—	9,979	1,836	997
Other income (expense), net	(267)	99	—	162	274
Interest expense	(2,976)	(4,133)	—	(3,643)	(707)
Income/(Loss) From Continuing Operations Before Income Taxes	8,087	496	9,534	(831)	651
Income Tax Expense/(Benefit)	—	—	—	357	(298)
Income/(Loss) from Continuing Operations	8,087	496	9,534	(1,188)	949
Income/(Loss) on Discontinued Operations, net of Income Taxes	—	—	—	(248)	—
Net Income/(Loss)	8,087	496	9,534	(1,436)	949
Balance Sheet					
Equity investments in affiliates	1,281	—	304,267	96,249	136,129
Total Assets	$2,178,681	$1,128,404	$355,184	$2,052,100	$945,096

	Reorganized NRG December 6, 2003 Through December 31, 2003				
	All Other				
	Wholesale Power Generation				
	Other International	Alternative Energy	Non-Generation	Other	Total
	(In thousands)				
Operations					
Operating Revenues	$ 13,082	$ 3,852	$ 9,860	$ (1,160)	$ 138,490
Depreciation and amortization	212	324	497	438	11,808
Reorganization items	**1**	**—**	**—**	**2,192**	**2,461**
Operating Income/(Loss)	**2,071**	**103**	**1,514**	**(3,976)**	**16,162**
Minority interest in earnings of consolidated subsidiaries	**—**	**—**	**—**	**—**	**(134)**
Equity in earnings of unconsolidated affiliates	**709**	**—**	**—**	**—**	**13,521**
Other income (expense), net	**905**	**152**	**77**	**(1,305)**	**97**
Interest expense	**(420)**	**(1)**	**(619)**	**(6,403)**	**(18,902)**
Income/(Loss) From Continuing Operations Before Income Taxes	**3,265**	**254**	**972**	**(11,684)**	**10,744**
Income Tax Expense/(Benefit)	**1,045**	**—**	**45**	**(1,810)**	**(661)**
Income/(Loss) from Continuing Operations	**2,220**	**254**	**927**	**(9,874)**	**11,405**
Income/(Loss) on Discontinued Operations, net of Income Taxes	**(64)**	**(68)**	**—**	**—**	**(380)**
Net Income/(Loss)	**2,156**	**186**	**927**	**(9,874)**	**11,025**
Balance Sheet					
Equity investments in affiliates	**196,488**	**458**	**—**	**3,126**	**737,998**
Total Assets	**$1,058,072**	**$ 71,886**	**$334,663**	**$1,120,901**	**$9,244,987**

	Predecessor Company January 1, 2003 through December 5, 2003 Wholesale Power Generation				
	Northeast	South Central	West Coast	Other North America	Australia
	(In thousands)				
Operations					
Operating Revenues	$ 861,452	$ 356,534	$ 23,956	$ 85,388	$151,494
Depreciation and amortization	90,132	33,987	10,750	38,046	17,114
Legal settlement	—	—	—	4,000	—
Fresh start reporting adjustments	1,067,783	428,823	106,523	515,166	77,593
Reorganization items	1,813	28,769	—	41,717	—
Restructuring and impairment charges	232,170	1,574	—	17,994	5
Operating Income/(Loss)	(1,330,587)	(383,527)	(101,366)	(577,190)	(68,030)
Equity in earnings of unconsolidated affiliates	—	—	102,681	7,260	30,364

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Predecessor Company January 1, 2003 through December 5, 2003 Wholesale Power Generation				
	Northeast	South Central	West Coast	Other North America	Australia
	(In thousands)				
Write downs and losses on sales of equity method investments	—	—	—	12,125	(146,354)
Other income (expense), net	2,308	699	8	2,832	(934)
Interest expense	(69,663)	(73,968)	—	(92,031)	(4,176)
Income/(Loss) From Continuing Operations Before Income Taxes	(1,397,942)	(456,796)	1,323	(647,004)	(189,130)
Income Tax Expense/(Benefit)	—	—	35,746	5,440	15,155
Income/(Loss) from Continuing Operations	(1,397,942)	(456,796)	(34,423)	(652,444)	(204,285)
Income/(Loss) on Discontinued Operations, net of Income Taxes	—	—	—	(279,639)	—
Net Income/(Loss)	(1,397,942)	(456,796)	(34,423)	(932,083)	(204,285)
Balance Sheet					
Equity investments in affiliates	1,281	—	309,900	92,965	131,864
Total Assets	$ 2,264,007	$1,328,663	$363,691	$2,051,790	$ 942,397

	Predecessor Company January 1, 2003 Through December 5, 2003				
	All Other				
	Wholesale Power Generation				
	Other International	Alternative Energy	Non-Generation	Other	Total
	(In thousands)				
Operations					
Operating Revenues	$ 137,384	$ 60,871	$ 129,063	$ (7,755)	$ 1,798,387
Depreciation and amortization	3,550	4,602	11,870	8,792	218,843
Legal settlement	—	(9,369)	—	468,000	462,631
Fresh start reporting adjustments	(10,676)	50,290	181,459	(6,535,597)	(4,118,636)
Reorganization items	—	—	—	125,526	197,825
Restructuring and impairment charges	133	1,067	26	(15,394)	237,575
Operating Income/(Loss)	33,345	(38,079)	(150,779)	5,890,123	3,273,910
Equity in earnings of unconsolidated affiliates	31,536	(940)	—	—	170,901
Write downs and losses on sales of equity method investments	3,389	(16,284)	—	—	(147,124)
Other income (expense), net	12,647	2,522	75	(948)	19,209
Interest expense	(7,896)	(153)	(9,805)	(72,197)	(329,889)
Income/(Loss) From Continuing Operations Before Income Taxes	73,021	(52,934)	(160,509)	5,816,978	2,987,007
Income Tax Expense/(Benefit)	16,843	1,597	395	(37,247)	37,929

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Predecessor Company January 1, 2003 Through December 5, 2003				
	Wholesale Power Generation	All Other			
	Other International	Alternative Energy	Non-Generation	Other	Total
	(In thousands)				
Income/(Loss) from Continuing Operations	56,178	(54,531)	(160,904)	5,854,225	2,949,078
Income/(Loss) on Discontinued Operations, net of Income Taxes	137,819	(25,123)	—	(15,690)	(182,633)
Net Income/(Loss)	193,997	(79,654)	(160,904)	5,838,535	2,766,445
Balance Sheet					
Equity investments in affiliates	194,880	458	—	2,514	733,862
Total Assets	$ 926,103	$ 73,048	$ 329,597	$ 888,033	$9,167,329

	Predecessor Company Year Ended December 31, 2002 Wholesale Power Generation				
	Northeast	South Central	West Coast	Other North America	Australia
	(In thousands)				
Operations					
Operating Revenues	$ 964,196	$ 388,023	$ 30,796	$ 81,521	$ 170,761
Depreciation and amortization	83,757	35,965	11,243	34,338	14,849
Restructuring and impairment charges	51,130	139,929	—	1,840,652	(16,265)
Operating Income/(Loss)	116,189	(46,836)	16,795	(1,857,128)	14,383
Equity in earnings of unconsolidated affiliates	—	(3,146)	24,012	23,287	15,680
Write downs and losses on sales of equity method investments	—	(48,375)	—	5,386	(129,190)
Other income (expense), net	5,822	922	—	1,359	(1,423)
Interest expense	(67,820)	(74,940)	(160)	(88,192)	(4,212)
Income/(Loss) From Continuing Operations Before Income Taxes	54,191	(172,375)	40,647	(1,915,288)	(104,762)
Income Tax Expense/(Benefit)	—	—	5,843	8,848	(3,033)
Income/(Loss) from Continuing Operations	54,191	(172,375)	34,804	(1,924,136)	(101,729)
Income/(Loss) on Discontinued Operations, net of Income Taxes	—	—	—	(93,755)	—
Net Income/(Loss)	54,191	(172,375)	34,804	(2,017,891)	(101,729)
Balance Sheet					
Equity investments in affiliates	—	—	398,786	122,007	110,123
Total Assets	$2,672,514	$1,393,012	$442,227	$ 3,028,444	$ 397,895

	Predecessor Company Year Ended December 31, 2002				
	Wholesale Power Generation	All Other			
	Other International	Alternative Energy	Non-Generation	Other	Total
	(In thousands)				
Operations					
Operating Revenues	$ 108,379	$ 69,030	$135,403	$ (9,816)	$ 1,938,293
Depreciation and amortization	1,242	5,441	12,584	7,608	207,027
Restructuring and impairment charges	71,108	27,893	31	448,582	2,563,060
Operating Income/(Loss)	(60,536)	(32,760)	41,831	(575,030)	(2,383,092)
Equity in earnings of unconsolidated affiliates	33,617	(24,454)	—	—	68,996
Write downs and losses on sales of equity method investments	(12,751)	(15,542)	—	—	(200,472)
Other income (expense), net	10,680	1,503	(142)	(7,290)	11,431
Interest expense	(3,030)	(3,666)	(8,946)	(201,216)	(452,182)
Income/(Loss) From Continuing Operations Before Income Taxes	(32,020)	(74,919)	32,743	(783,536)	(2,955,319)
Income Tax Expense/(Benefit)	14,982	(16,943)	11,654	(188,218)	(166,867)
Income/(Loss) from Continuing Operations	(47,002)	(57,976)	21,089	(595,318)	(2,788,452)
Income/(Loss) on Discontinued Operations, net of Income Taxes	(550,877)	(31,199)	—	1	(675,830)
Net Income/(Loss)	(597,879)	(89,175)	21,089	(595,317)	(3,464,282)
Balance Sheet					
Equity investments in affiliates	201,007	21,942	—	30,398	884,263
Total Assets	$1,973,089	$ 128,010	$312,994	$ 548,666	$10,896,851

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Predecessor Company Year Ended December 31, 2001 Wholesale Power Generation				
	Northeast	South Central	West Coast	Other North America	Australia
			(In thousands)		
Operations					
Operating Revenues	$1,206,611	$401,519	$ 23,201	$ (8,686)	$213,287
Depreciation and amortization	63,908	29,427	9,941	1,931	14,570
Operating Income/(Loss)	340,675	85,931	13,183	(7,947)	15,321
Equity in earnings of unconsolidated affiliates	—	(2,435)	162,560	18,000	7,543
Other income (expense), net	4,760	(190)	6,325	2,944	(2,286)
Interest expense	(70,483)	(72,101)	(64)	1,275	(3,856)
Income/(Loss) From Continuing Operations Before Income Taxes	274,952	11,205	182,004	14,272	16,722
Income Tax Expense/(Benefit)	(4,894)	—	70,044	8,998	6,472
Income/(Loss) from Continuing Operations	279,846	11,205	111,960	5,274	10,250
Income/(Loss) on Discontinued Operations, net of Income Taxes	—	—	—	9,692	—
Net Income/(Loss)	$ 279,846	$ 11,205	$111,960	$ 14,966	$ 10,250

	Predecessor Company Year Ended December 31, 2001				
	All Other				
	Wholesale Power Generation				
	Other International	Alternative Energy	Non-Generation	Other	Total
			(In thousands)		
Operations					
Operating Revenues	$ 72,757	$ 53,035	$127,898	$ (4,272)	$2,085,350
Depreciation and amortization	417	4,378	13,197	3,207	140,976
Operating Income/(Loss)	(4,678)	1,445	34,228	(96,339)	381,819
Equity in earnings of unconsolidated affiliates	51,258	(26,883)	(11)	—	210,032
Other income (expense), net	8,039	477	214	2,700	22,983
Interest expense	(4,895)	(1,725)	(7,021)	(205,241)	(364,111)
Income/(Loss) From Continuing Operations Before Income Taxes	49,724	(26,686)	27,410	(298,880)	250,723
Income Tax Expense/(Benefit)	6,709	(44,619)	10,161	(12,650)	40,221
Income/(Loss) from Continuing Operations	43,015	17,933	17,249	(286,230)	210,502
Income/(Loss) on Discontinued Operations, net of Income Taxes	44,661	349	—	—	54,702
Net Income/(Loss)	$ 87,676	$ 18,282	$ 17,249	$(286,230)	$ 265,204

Note 21 — Income Taxes

For the year ended December 31, 2002 and the period January 1, 2003 through December 5, 2003, income taxes have been recorded on the basis that Xcel Energy will not be including us in its consolidated federal income tax return following Xcel Energy's acquisition of our public shares on June 3, 2002. Since our U.S. subsidiaries and we will not be included in the Xcel Energy consolidated federal income tax return for the period January 1, 2003 through December 5, 2003, we and each of our U.S. subsidiaries that is classified as a corporation for U.S. income tax purposes must file separate federal income tax returns.

Following our emergence from bankruptcy on December 5, 2003, we and our U.S. subsidiaries will file a consolidated federal income tax return. We have reviewed the requirements for reconsolidation and believe we satisfy them.

The provision (benefit) for income taxes consists of the following:

	Predecessor Company			Reorganized NRG
	Year Ended December 31,		For the Period January 1 — December 5,	For the Period December 6 — December 31,
	2001	2002	2003	2003
	(In thousands)			
Current				
U.S.	$ 28,792	$ 10,409	$ 2,231	**$ (1,513)**
Foreign	10,025	17,160	15,630	**1,184**
	38,817	27,569	17,861	**(329)**
Deferred				
U.S.	31,820	(191,447)	3,292	**59**
Foreign	4,529	(2,989)	16,776	**(391)**
	36,349	(194,436)	20,068	**(332)**
Tax credits recognized	(34,945)	—	—	**—**
Total income tax (benefit)	$ 40,221	$(166,867)	$ 37,929	**$ (661)**
Effective tax rate	16.0%	5.6%	1.3%	**(6.2)%**

The pre-tax income (loss) from U.S. and foreign entities was as follows:

	Predecessor Company			Reorganized NRG
	Year Ended December 31,		For the Period January 1 — December 5,	For the Period December 6 — December 31,
	2001	2002	2003	2003
	(In thousands)			
U.S.	$184,260	$(2,818,537)	$3,103,117	**$ 6,828**
Foreign	66,463	(136,782)	(116,110)	**3,916**
	$250,723	$(2,955,319)	$2,987,007	**$ 10,744**

The components of the net deferred income tax liability were:

	Predecessor Company	Reorganized NRG	
	December 31, 2002	December 6, 2003	December 31, 2003
		(In thousands)	
Deferred tax liabilities:			
Difference between book and tax basis of property	$ 368,712	$ —	$ —
Discount/premium on notes	—	34,602	34,136
Emissions credits	—	147,811	147,811
Net unrealized gains on mark to market transactions	37,800	14,868	12,461
Other	9,167	988	988
Total deferred tax liabilities	$ 415,679	$ 198,269	$ 195,396
Deferred tax assets:			
Deferred compensation, accrued vacation and other reserves	53,907	55,734	55,063
Development costs	11,079	3,017	2,999
Foreign tax loss carryforwards	231,668	341,991	342,017
Differences between book and tax basis of contracts	24,155	222,655	199,940
Difference between book and tax basis of property	702,905	72,820	79,070
Intangibles amortization (other than goodwill)	—	13,191	13,053
Restructuring costs	—	20,462	20,468
U.S. tax loss carry forwards	456,460	389,020	402,940
Investments in projects	7,967	164,343	159,370
Other	22,953	11,964	13,934
Total deferred tax assets (before valuation allowance)	1,511,094	1,295,197	1,288,854
Valuation allowance	(1,170,301)	(1,241,616)	(1,241,101)
Net deferred tax assets	340,793	53,581	47,753
Net deferred tax liability	$ 74,886	$ 144,688	$ 147,643

The net deferred tax liability consists of:

	Predecessor Company	Reorganized NRG	
	December 31, 2002	December 6, 2003	December 31, 2003
		(In thousands)	
Current deferred tax asset	$ —	$ —	$ 1,850
Non-current deferred tax liability	74,886	144,688	149,493
Net deferred tax liability	$ 74,886	$ 144,688	$ 147,643

As of December 31, 2003, we provided a valuation allowance of approximately $556.6 million to account for potential limitations on utilization of U.S. and foreign net operating loss carryforwards. If unused, the U.S. net operating loss carryforward of $1.0 billion generated in 2002 and 2003, will expire by 2023. Net operating loss carryforwards for foreign tax purposes have no expiration date. We also have a valuation allowance for other U.S. and foreign deferred income tax assets of approximately $684.5 million as of December 31, 2003.

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. As noted above, 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.

As of December 5, 2003, we provided a valuation allowance of approximately $542.0 million to account for potential limitations on utilization of U.S. and foreign net operating loss carryforwards compared to a valuation allowance of $494.5 million for the same period in 2002. We also provided a valuation allowance for other U.S. and foreign deferred income tax assets of approximately $699.7 million for the period ended December 5, 2003 compared to $578.7 million for the same period in 2002.

The effective income tax rates of continuing operations for the years ended December 31, 2001, 2002 and 2003 differ from the statutory federal income tax rate of 35% as follows:

	Predecessor Company						Reorganized NRG	
	Year Ended December 31,				For the Period January 1 – December 5, 2003		For the Period December 6 – December 31, 2003	
	2001		2002					
Income/ (Loss) From Continuing Operations Before Income Taxes	$250,723		$(2,955,319)		$ 2,987,007		$10,744	
Tax at 35%	87,753	35.0%	(1,034,362)	35.0%	1,045,452	35.0%	3,760	35.0%
State taxes, (net of federal benefit)	7,428	2.9%	(167,405)	5.7%	254,112	8.5%	(1,834)	(17.1)%
Foreign operations	(29,125)	(11.6)%	(18,522)	0.6%	15,001	0.5%	(1,265)	(11.8)%
Fresh Start accounting adjustments	—	—	—	—	(1,383,334)	(46.3)%	—	—
Tax credits	(34,945)	(13.9)%	—	—	—	—	—	—
Valuation allowance	21,389	8.5%	1,006,540	(34.1)%	71,315	2.4%	(515)	(4.8)%
Change in tax rate	—	—	—	—	36,018	1.2%	—	—
Permanent differences, reserves, other	(12,279)	(4.9)%	46,882	(1.6)%	(635)	—	(807)	(7.5)%
Income Tax Expense/ (Benefit)	$ 40,221	16.0%	$ (166,867)	5.6%	$ 37,929	1.3%	$ (661)	(6.2)%

Income tax benefit/expense for the period December 6, 2003 through December 31, 2003 was a tax benefit of $0.7 million which includes $1.5 million benefit and $0.8 million expense of U.S. and foreign taxes, respectively. The U.S. tax benefit recorded for this period is the result of a state tax refund received from Xcel Energy pursuant to the tax matters agreement. The foreign tax expense for the period is due to earnings in the foreign jurisdictions.

The income tax benefit/expense for the period January 1, 2003 through December 5, 2003 was a tax expense of $37.9 million compared to a tax benefit of $166.9 million for the year ended December 31, 2002. During 2003, an additional valuation allowance of $33 million was recorded against the deferred tax assets of NRG West Coast as a result of its conversion from a corporation to a single member limited liability company (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 us.

As of December 31, 2003, our management intends to indefinitely reinvest the earnings from our foreign operations. Accordingly, U.S. income taxes and foreign withholding taxes were not provided on the earnings from our foreign subsidiaries. As of December 31, 2003, December 5, 2003, and December 31, 2002 no U.S. income tax benefit was provided on the cumulative amount of losses from our foreign subsidiaries of $387.5 million, $438.4 million, and $341.7 million, respectively.

Note 22 — Related Party Transactions

While we were an indirect, wholly owned subsidiary of Xcel Energy, 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. Prior to December 5, 2003, we had entered into material transactions and agreements with Xcel Energy. Certain material agreements and transactions existing during 2003 between NRG Energy and Xcel Energy are described below.

Operating Agreements

We have two agreements with Xcel Energy for the purchase of thermal energy. Under the terms of the agreements, Xcel Energy charges us for certain costs (fuel, labor, plant maintenance, and auxiliary power) incurred by Xcel Energy to produce the thermal energy. We paid Xcel Energy $7.1 million, $8.2 million and $9.6 million in 2001, 2002 and the period January 1, 2003 to December 5, 2003, respectively, under these agreements. One of these agreements expired on December 31, 2002 and the other expires on December 31, 2006.

We have a renewable 10-year agreement with Xcel Energy, expiring on December 31, 2006, whereby Xcel Energy agreed to purchase refuse-derived fuel for use in certain of its boilers and we agree to pay Xcel Energy a burn incentive. Under this agreement, we received $1.6 million, $1.2 million and $1.4 million from Xcel Energy, and paid $2.8 million, $3.3 million and $3.9 million to Xcel Energy in 2001, 2002 and the period January 1, 2003 to December 5, 2003, respectively.

Administrative Services and Other Costs

We had an administrative services agreement in place with Xcel Energy. Under this agreement we reimbursed Xcel Energy for certain overhead and administrative costs, including benefits administration, engineering support, accounting, and other shared services as requested by us. In addition, our employees participated in certain employee benefit plans of Xcel Energy as discussed in Note 23. We reimbursed Xcel Energy in the amounts of $12.2 million, $21.2 million and $7.3 million during 2001, 2002 and the period January 1, 2003 to December 5, 2003, respectively, under this agreement. This agreement was terminated December 5, 2003.

Natural Gas Marketing and Trading Agreement

We had an agreement with e prime, a wholly owned subsidiary of Xcel Energy, under which e prime provided natural gas marketing and trading from time to time at our request. We paid $19.2 million to e prime in 2002 related to these services. This agreement was terminated by e prime on December 12, 2002 and a termination charge of $0.3 million was paid in the period January 1, 2003 to December 5, 2003.

Amounts owed to Xcel Energy

Included in accounts payable affiliate is approximately $42.9 million of amounts owed to Xcel Energy at December 31, 2002. While we were an indirect, wholly owned subsidiary of Xcel Energy, we became an independent public company upon our emergence from bankruptcy on December 5, 2003. As part of our restructuring, amounts owed to Xcel Energy were forgiven and replaced by a $10.0 million promissory note, which was outstanding as of December 6, 2003 and December 31, 2003.

Xcel Settlement Agreement

Included in the company's balance sheet is a $640.0 million receivable from Xcel Energy. Under the terms of the settlement agreement, payments were to be made in three installments. As of December 6, 2003 and December 31, 2003, the balance was $640.0 million.

Note 23 — 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. On December 5, 2003, we recorded a liability of approximately $48.0 million to record our accumulated benefit obligations at fair value. As of December 31, 2003, there were no plan assets related to the plans assumed from Xcel Energy. We have chosen the plan Trustee and are in the preliminary stages of defining the investment strategies for this plan.

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.

Cash Flow

We expect to contribute approximately $2.0 million to our NRG pension plan and our postretirement health and welfare plan in 2004.

NRG Flinders Retirement Plan

Employees of NRG Flinders, a wholly owned subsidiary of NRG Energy, are members of the multiemployer Electricity Industry Superannuation Schemes, or "EISS." Members of the EISS make contributions from their salary and the EISS Actuary makes an assessment of our liability. As a result of adopting Fresh Start we recorded a liability of approximately $13.8 million at December 5, 2003, to record our accumulated benefit obligation plan assets on the balance sheet at fair value. The balance sheet includes a liability related to the Flinders retirement plan of $12.3 million, $13.8 million and $13.7 million at December 31, 2002, December 5, 2003 and December 31, 2003, respectively. NRG Flinders contributed $5.8 million, $4.5 million and $0 for the year ended December 31, 2002, the period January 1 through December 5, 2003 and the period December 6 through December 31, 2003, respectively.

The Superannuation Board is responsible for the investment of Scheme assets. The assets may be invested in government securities, shares, property and a variety of other securities and the Board may appoint professional investment managers to invest all or part of the assets on its behalf.

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				Other Benefits			
	Predecessor Company			Reorganized NRG	Predecessor Company			Reorganized NRG
	Year Ended December 31, 2001	Year Ended December 31, 2002	For the Period January 1 – December 5, 2003	For the Period December 6 – December 31, 2003	Year Ended December 31, 2001	Year Ended December 31, 2002	For the Period January 1 – December 5, 2003	For the Period December 6 – December 31, 2003
			(In thousands)				(In thousands)	
Service cost benefits earned	$ —	$ —	$ —	**$ 800**	$ 902	$1,206	$ 1,220	**$ 130**
Interest cost on benefit obligation	—	—	—	**205**	1,402	1,831	1,900	**180**
Amortization of prior service cost	—	—	—	**—**	(25)	(24)	(22)	**—**
Expected return on plan assets	—	—	—	**—**	—	—	—	**—**
Recognized actuarial (gain)/loss	—	—	—		(56)	5	178	**—**
Net periodic benefit cost	$ —	$ —	$ —	**$ 1,005**	$2,223	$3,018	$ 3,276	**$ 310**

Reconciliation of Funded Status

A comparison of the pension benefit obligation and pension assets at December 6, 2003 and December 31, 2003 for all of our plans on a combined basis is as follows:

	Pension Benefits		Other Benefits	
Reorganized NRG	December 6, 2003	December 31, 2003	December 6, 2003	December 31, 2003
	(In thousands)			
Benefit obligation at Jan. 1/Dec. 6	$ —	$ 47,950	$ 31,584	$ 41,900
Service cost	—	800	1,220	130
Interest cost	—	205	1,900	180
Plan initiation	47,950	—	—	—
Employee contributions	—	—	—	—
Plan amendments	—	—	2,100	—
Actuarial (gain)/loss	—	—	5,396	—
Benefit payments	—	—	(300)	(40)
Foreign currency translation	—	—	—	—
Benefit obligation at Dec. 5/Dec. 31	$ 47,950	$ 48,955	$ 41,900	$ 42,170
Fair value of plan assets at Jan. 1/Dec. 6	$ —	$ —	$ —	$ —
Actual return on plan assets	—	—	—	—
Employee contributions	—	—	—	—
Employer contributions	—	—	300	40
Benefit payments	—	—	(300)	(40)
Foreign currency translation	—	—	—	—
Fair value of plan assets at Dec. 5/Dec. 31	$ —	$ —	$ —	$ —
Funded status at Dec. 5/Dec. 31 — excess of obligation over assets	$ (47,950)	$ (48,955)	$ (41,900)	$ (42,170)
Unrecognized prior service cost	—	—	—	—
Unrecognized net (gain) loss	—	—	—	—
Accrued benefit liability recognized on the consolidated balance sheet at Dec. 5/Dec. 31	$ (47,950)	$ (48,955)	$ (41,900)	$ (42,170)

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

A comparison of the pension benefit obligation and pension assets at December 31, 2002 for all of our plans on a combined basis is as follows:

Predecessor Company	Pension Benefits 2002	Other Benefits 2002
	(In thousands)	
Benefit obligation at Jan. 1	$ —	$ 24,602
Service cost	—	1,206
Interest cost	—	1,831
Plan initiation	—	—
Employee contributions	—	—
Plan amendments	—	—
Actuarial (gain)/loss	—	4,101
Acquisitions (transfers)	—	—
Benefit payments	—	(156)
Foreign currency translation	—	—
Benefit obligation at Dec. 31	$ —	$ 31,584
Fair value of plan assets at Jan. 1	$ —	$ —
Actual return on plan assets	—	—
Employee contributions	—	—
Employer contributions	—	156
Benefit payments	—	(156)
Foreign currency translation	—	—
Fair value of plan assets at Dec. 31	$ —	$ —
Funded status at Dec. 31 — excess of obligation over assets	$ —	$ (31,584)
Unrecognized prior service cost	—	(229)
Unrecognized net (gain) loss	—	5,967
Accrued benefit liability recognized on the consolidated balance sheet at Dec. 31	$ —	$ (25,846)

The following table presents significant assumptions used:

	Pension Benefits		Other Benefits	
	2002	2003	2002	2003
Weighted-average assumption as of December 31,				
Discount rate	—	6.00%	6.75%	6.00%
Expected return on plan assets	—	NA*	—	—
Rate of compensation increase	—	4.50	3.50-4.50	4.50

* We did not determine an expected return on plan assets for the NRG pension plan, as there are no plan assets at December 31, 2003.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effect (in thousands):

	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost components	$ 440	$ (400)
Effect on postretirement benefit obligation	4,175	(4,048)

Defined Contribution Plans

Our employees have also been eligible to participate in defined contribution 401(K) plans. Our contributions to these plans were approximately $3.2 million, $4.6 million and $3.8 million in 2001, 2002 and 2003, respectively.

Predecessor Company

Prior to December 5, 2003, all eligible employees participated in Xcel Energy's multiemployer noncontributory, defined benefit pension plan, which was formerly sponsored by NSP. We sponsored two defined benefit plans that were merged into Xcel Energy's plan as of June 30, 2002. Benefits are generally based on a combination of an employee's years of service and earnings. Some formulas also take into account Social Security benefits. Plan assets principally consisted of the common stock of public companies, corporate bonds and U.S. government securities.

Prior to December 5, 2003, certain former NRG Energy retirees were covered under the legacy Xcel Energy plan, which was terminated for non-bargaining employees retiring after 1998 and for bargaining employees retiring after 1999.

As a result of our emergence from bankruptcy on December 5, 2003, we are no longer owned by or affiliated with Xcel Energy and our employees are no longer participants of the Xcel Energy plans.

Participation in Xcel Energy, Inc. Pension Plan and Postretirement Medical Plan

We did not make contributions to the Xcel Energy pension plan and postretirement plan in 2001, 2002 or 2003. The balance sheet includes a liability related to the Xcel Energy Pension Plan of $1.7 million for 2002. The balance sheet also includes a liability related to the Xcel Energy Postretirement Medical Plan of $2.2 million for 2002. As of December 31, 2003, there are no liabilities recorded related to the Xcel Energy plans. The liabilities associated with these plans were settled as part of the NRG plan of reorganization. The net annual periodic cost (credit) related to our portion of the Xcel Energy pension plan and postretirement plans totaled $(8.9) million, $(8.9) million and $0.2 million for 2001, 2002 and 2003, respectively.

Prior to December 5, 2003, certain employees also participated in Xcel Energy's noncontributory defined benefit supplemental retirement income plan. This plan is for the benefit of certain qualifying executive personnel. Benefits for this unfunded plan are paid out of operating cash flows. The balance sheet includes a liability related to this plan of $3.2 million and $0.4 million as of December 31, 2002 and 2003, respectively.

2003 Medicare Legislation

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug Improvement and Modernization Act of 2003, or "the Act." The Act expanded Medicare to include, for the first time, coverage for prescription drugs. This coverage is generally effective January 1, 2006. The execution of this new legislation had no significant impact on our statement of financial position or results of operation as of

December 31, 2003 and for the period December 6, 2003 through December 31, 2003. Any future impact will be recognized as incurred.

Note 24 — Commitments and Contingencies

Operating Lease Commitments

We lease certain of our facilities and equipment under operating leases, some of which include escalation clauses, expiring on various dates through 2023. Rental expense under these operating leases was $10.0 million, and $13.4 million for the years ended December 31, 2001 and 2002, respectively and $12.2 million and $0.7 million for the periods January 1, 2003 through December 5, 2003 and December 6, 2003 through December 31, 2003, respectively. Future minimum lease commitments under these leases for the years ending after December 31, 2003 are as follows:

	Continuing Operations	Discontinued Operations	Total
		(In thousands)	
2004	$ 8,760	$ 464	$ 9,224
2005	7,770	363	8,133
2006	7,029	362	7,391
2007	3,971	343	4,314
2008	3,161	365	3,526
Thereafter	14,934	—	14,934
Total	$ 45,625	$ 1,897	$47,522

Capital Commitments

We anticipate funding our ongoing capital requirements through committed debt facilities, operating cash flows, and existing cash. Our capital expenditure program is subject to continuing review and modification. The timing and actual amount of expenditures may differ significantly based upon plant operating history, unexpected plant outages, and changes in the regulatory environment, and the availability of cash.

NRG FinCo Settlement

In May 2001, our wholly-owned subsidiary, NRG FinCo, entered into a $2.0 billion revolving credit facility. The facility was established to finance the acquisition, development and construction of power generating plants located in the United States and to finance the acquisition of turbines for such facilities. The facility provided for borrowings of base rate loans and Eurocurrency loans and was secured by mortgages and security agreements in respect of the assets of the projects financed under the facility, pledges of the equity interests in the subsidiaries or affiliates of the borrower that own such projects, and by guaranties from each such subsidiary or affiliate. The NRG FinCo secured revolver was initially scheduled to mature on May 8, 2006; however, due to defaults hereunder by NRG FinCo and applicable guarantors, the lenders accelerated all outstanding obligations on November 6, 2002. As of our emergence, $1.1 billion was outstanding under the facility, and there was an aggregate of approximately $58 million of accrued but unpaid interest and commitment fees. Of this, $842.0 million was allowed in unsecured claims under NRG plan of reorganization, and was settled at the time of our emergence. The remaining balance will be satisfied when the NRG FinCo lenders exercise their perfected security interests in our Nelson, Audrain and Pike projects. These project companies hold assets with estimated fair market values of approximately $55.2 million, $172.0 million and $48.0 million, respectively. The amount of $55.2 million for Nelson consists of a partially completed project. Since the Nelson entity is currently in bankruptcy, we are recording the entity as a cost method investment with the fair value of the assets equaling the fair value of the obligation to the NRG FinCo lenders. The Audrain project cost of $172.0 million represents the fair value of the operating assets consisting of property plant and equipment. An offsetting liability of $172.0 million was recorded as of Fresh Start to the NRG FinCo lenders. The Pike entity holds a turbine with an estimated fair value of approximately $48.0 million. Additionally, we also recorded an equal liability of $48.0 million to the NRG FinCo lenders. The obligations of Audrain and Pike totaling $220.0 million is reflected on the balance sheet as other bankruptcy settlement. We are in the process of marketing for sale each of the Audrain, Pike, and Nelson projects on behalf of the NRG FinCo lenders. The NRG FinCo lenders have authority under their perfected security interest to accept or reject all offers. As a result these entities are not reflected as a discontinued operations. We believe we have no additional risk of loss related to these entities.

In connection with our acquisition of the Audrain facilities, we have recognized a capital lease on its balance sheet within long-term debt in the amount of $239.9 million, as of December 31, 2003 and 2002. The capital lease obligation is recorded at the net present value of the minimum lease obligation payable. The lease terminates in May 2023. During the term of the lease only interest payments are due, no principal is due until the end of the lease. In addition, we have recorded in notes receivable, an amount of approximately $239.9 million, which represents its investment in the bonds that the county of Audrain issued to finance the project. During February 2004, we received a notice of a waiver of a $24.0 million interest payment due on the capital lease obligation. In connection with the transfer of the security in the Audrain projects to NRG FinCo Lenders, the Audrain entity will be liquidated resulting in the termination of the lease obligation and the note receivable.

Environmental Regulatory 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 our facilities are not exempted from coverage, we could be required to make extensive modifications to further reduce potential environmental impacts.

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 we have been involved in on-site contamination matters, to date, we have not been named as a potentially responsible party with respect to any off-site waste disposal matter.

We strive to exceed the standards of compliance with applicable environmental and safety regulations. Nonetheless, we expect that future liability under or compliance with environmental and safety requirements could have a material effect on our 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 our operations.

As part of acquiring existing generating assets, we have 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.

West Coast Region

The Asset Purchase Agreements for the Long Beach, El Segundo, Encina, and San Diego gas turbine generating facilities provide that Southern California Edison and San Diego Gas & Electric retain liability and indemnify us for existing soil and groundwater contamination that exceeds remedial thresholds in place at the time of closing. Along with our business partner, we conducted Phase I and Phase II Environmental Site Assessments at each of these sites for purposes of identifying such existing contamination and provided the results to the sellers. San Diego Gas & Electric has undertaken corrective actions at the Encina and San Diego gas turbine generating sites related to issues identified in these assessments, although final government agency approval to certify completeness of the corrective action has not yet been obtained. While spills and releases of various substances have occurred at many sites since establishing the historical baseline, all but one has been remediated in accordance with existing laws. An unquantified amount of soil contaminated by lubricating oil that leaked from underground piping at the El Segundo Generating Station has been allowed by the Regional Water Quality Control Board to remain under the foundation of the Unit I powerhouse until the building is demolished.

Our affiliates have incurred capital expenditures at the Encina Generating Station to install Selective Catalytic Reduction, or “SCR” emission control technology on all five generating units. Units 4 & 5 were retrofitted with SCRs during 2002; while Units 1, 2, and 3 were retrofitted with SCRs in 2003. The cost to retrofit all five units totaled approximately $42 million.

Eastern Region

Coal ash is produced as a by-product of coal combustion at the Dunkirk, Huntley, and Somerset Generating Stations. We attempt to direct its coal ash to beneficial uses. Even so, significant amounts of ash are landfilled at on and off-site locations. At Dunkirk and Huntley, ash is disposed at landfills owned and operated by us. No material liabilities outside the costs associated with closure, post-closure care and monitoring are expected at these facilities. We maintain financial assurance to cover costs associated with closure, post-closure care and monitoring activities. In the past, we have provided financial assurance via financial test and corporate guarantee. As a result of our debt restructuring process, we were required to re-establish financial assurance via an instrument requiring complete collateralization of closure and post-closure-related costs, such costs currently estimated at approximately $5.9 million. We provided such financial assurance via a trust fund established in this amount on April 30, 2003.

We must also maintain financial assurance for closing interim status RCRA facilities at the Devon, Middletown, Montville and Norwalk Harbor Generating Stations. Previously, we have provided financial assurance via financial test. As a result of our debt restructuring process, we were required to re-establish financial assurance via an instrument requiring complete collateralization of closure and post-closure-related costs, such costs currently estimated at approximately $1.5 million. We 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 Harbor, Arthur Kill and Astoria Generating Stations. We have 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 Harbor Stations have been identified and are currently being refined as part of on-going site investigations. We do not expect to incur material costs associated with completing the investigations at these Stations or future work to cover and monitor ash management areas pursuant to the Connecticut requirements. Remedial liabilities at the Arthur Kill Generating Station have been established in discussions between us and the New York State DEC and are expected to cost on the order of $1.0 million. Remedial investigations are on-going at the Astoria Generating Station. At this time, our long-term cleanup liability at this site is not expected to exceed $1.5 million.

We estimate that we will incur total environmental capital expenditures of $79.7 million during 2004 through 2008 for the facilities in New York, Connecticut and Massachusetts. These expenditures will be primarily related to changes required to accommodate Power River Basin coal at selected plants, landfill construction, installation of NO_x controls, installation of the best technology available for minimizing environmental impacts associated with impingement and entrainment of fish and larvae, particulate matter control improvements, spill prevention controls, and undertaking remedial actions. NRG Energy estimates that it will incur in 2004 at all of its plants in the Northeast Region approximately $23 million in capital expenditures for plant modifications and upgrades required to comply with environmental regulations.

As of December 31, 2003, we had recorded an accrual of approximately $2.1 million to cover penalties associated with historical opacity exceedances.

We are responsible for the costs associated with closure, post-closure care and monitoring of the ash landfill owned and operated by us on the site of the Indian River Generating Station. No material liabilities outside such costs are expected. Financial assurance to provide for closure and post-closure-related costs is currently maintained by a trust fund collateralized in the amount of approximately $6.6 million.

We estimate that we will incur capital expenditures of approximately $14.7 million during the years 2004 through 2008 related to resolving environmental concerns at the Indian River Generating Station. These concerns include the expected closure of the existing ash landfill, the construction of a new ash landfill nearby, the addition of controls to reduce NO_x emissions, fuel yard modifications, and electrostatic precipitator refurbishments to reduce opacity.

Central Region

Liabilities associated with closure, post-closure care and monitoring of the ash ponds owned and operated on site at the Big Cajun II Generating Station are addressed through the use of a trust fund maintained by us (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 current value of the trust fund is approximately $4.8 million and we are making annual payments to the fund in the amount of about $116,000. See Note 14.

We estimate approximately $18 million of capital expenditures will be incurred during the period 2004 through 2008 for the addition of NO_x controls on Units 1 and 2 of Big Cajun II. In addition, NRG Energy estimates that it would incur up to $5 million to reduce particulate matter emissions during start-up of Units 1 and 2 at Big Cajun II.

NYISO Claims

In November 2002, the NYISO notified us of claims related to New York City mitigation adjustments, general NYISO billing adjustments and other miscellaneous charges related to sales between November 2000 and October 2002. The New York City mitigation adjustments totaled $11.5 million. We 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 NRG would not have sufficient revenue to cover for subsequent revisions to its energy market settlements. As of December 31, 2003, the NYISO held $4.5 million in escrow for such future settlement revisions.

Conectiv Agreement Termination

On November 8, 2002 Conectiv provided us with a Notice of Termination of Transaction under the Master Power Purchase and Sale Agreement, or “Master PPA”, dated June 21, 2001. Under the Master PPA, which was assumed by us in our acquisition of various assets from Conectiv, we had been required to deliver 500 MW of electrical energy around the clock at a specified price through 2005. In connection with the Conectiv acquisition, we recorded as an out-of-market contract obligation for this contract. As a result of the cancellation, we will lose approximately $383.1 million in future contracted revenues. Also, in conjunction with the terms of the Master PPA, we received from Conectiv a termination payment in the amount of $955,000. At December 31, 2002, the remaining unamortized balance of the contract obligation was recognized as revenue. As a result, during the fourth quarter approximately $50.7 million was recognized as revenue.

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 power of California plants. Dynegy and its affiliates and subsidiaries are responsible for gas procurement and marketing and trading activities on behalf of West Coast Power. It alleges that the defendants violated California Business & Professions Code § 17200 by selling ancillary services to the Cal 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 has appealed that decision to the United States Court of Appeal for the Ninth Circuit, and the appeal is pending. 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, and the appeal was argued in August 2003 and also is pending.

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 plaintiffs have filed a notice of appeal, and the appeal is pending.

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 consolidated cases, which were all filed in late 2000 and 2001 in various state courts throughout California. They 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. 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 plaintiff's 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, Business and Professional Code, and 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 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.

California Investigations

FERC — California Market Manipulation

The Federal Energy Regulatory Commission has an ongoing “Investigation of Potential Manipulation of Electric and Natural Gas Prices,” which involves 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 have been 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 in Docket No. EL00-95-045, or “Refund Order”, 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 makes certain changes to Judge Birchman’s methodology, because of FERC Staff’s findings of manipulation in gas index prices. This could materially increase the estimated refund liability. 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 and the West Coast Power entities are currently engaged in settlement negotiations with FERC Staff, the California Attorney General, the California Public Utility Commission, the California Electricity Oversight Board, PG&E, and Southern California Edison.

CFTC — Dynegy/ West Coast Power Natural Gas Futures Index Manipulation

On December 18, 2002, a Dynegy subsidiary, Dynegy Marketing & Trade, or “DMT”, and West Coast Power, collectively “the Respondents”, entered into a consent Offer of Settlement and Order, “the Consent Order”, with the Commodity Futures and Trading Commission, or “CFTC.” The action is captioned In re Dynegy Marketing & Trade and West Coast Power LLC, CFTC Docket No. 03-03. The CFTC asserted various violations of the Commodity Exchange Act, as well as CFTC regulations.

The CFTC alleged in the Consent Order that DMT natural gas traders reported false natural gas trading information, including price and volume information, to certain industry publications that establish and publish indexes for natural gas prices. The CFTC alleged that DMT submitted the false information in an attempt to manipulate the indexes for DMT’s benefit. The CFTC further alleged that DMT traders directed other Dynegy personnel to report each of the same false trades in the name of West Coast Power, as counterparty, in an effort to lend credence to the trades’ validity. The Respondents to the Consent Order did not admit or deny the allegations or findings made by the CFTC, but agreed to an Offer of Settlement, and agreed to pay a civil monetary fine of $5 million. The Respondents also agreed to undertakings regarding further cooperation with the CFTC and public statements concerning the Consent Order. Dynegy agreed to pay and be entirely responsible for the $5 million fine imposed by the CFTC.

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 has 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 has 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 have also produced a large volume of documentation relating to the West Coast Power plants. In addition, our employees in California have sat for informal interviews with representatives of the Attorney General’s office. Dynegy employees have also been interviewed.

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 alleges that the defendants, collectively, overcharged California ratepayers during 2000 by $4.0 billion. We know of no evidence implicating us in the various private plaintiffs' allegations of collusion. We cannot predict the outcome of these cases and investigations at this time.

Electricity Consumers Resource Council v. Federal Energy Regulatory Commission, Case 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.

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. PMI cannot estimate at this time the likelihood of an unfavorable outcome in this matter, or the overall exposure for congestion charges for the full term of the contract.

Connecticut Light & Power Company, Docket No. EL03-135, pending at the Federal Energy Regulatory Commission

This matter involves a dispute between CL&P and PMI concerning which of party is responsible, under the terms of the October 29, 1999 SOS contract, for costs related to congestion and losses associated with the implementation of standard market design, or "SMD-Related Costs." CL&P has withheld, in addition to the $30 million discussed above, approximately $79 million from amounts owed to PMI, claiming that it is entitled under the contract to offset those additional amounts for SMD-Related Costs. The parties have now reached a settlement, subject to board approval, whereby CL&P will pay PMI $38.4 million plus interest, and subject to adjustments and true-ups upon final approval by FERC. The settlement agreement was filed with FERC on March 3, 2004.

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 et al., United States District Court for the Western District of New York, Civil Action No. 02-CV-002S

In January 2002, the New York Department of Environmental Conservation, or "DEC", sued Niagara Mohawk Power Corporation, or "NiMo", and us 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 with prejudice as to the federal claims and without prejudice as to the state claims. It is possible the state will appeal this dismissal to the Second Circuit Court of Appeals. In the meantime, 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. 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 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 us under the asset sales agreement. We have pending a summary judgment motion on its entitlement to be reimbursed by NiMo for the attorneys' fees we have incurred in the enforcement action.

Huntley Power LLC, Dunkirk Power LLC and Oswego Power LLC

The DEC has alleged violations by the Huntley Generating Station, the Dunkirk Generating Station and the Oswego Generating Station with respect to opacity exceedances. The above entities have been engaged in consent order negotiations with the DEC relative to such opacity issues affecting all three facilities since the plants were acquired. In late February, 2004, a representative of each of the six entities signed a proposed final version of the consent order, which, if executed and thereby issued by the DEC, would quantify the number of opacity exceedances at the three facilities through the second quarter of 2003 and assess a cumulative penalty of $1 million. In addition, among other provisions, the consent order would establish stipulated penalties for future violations of opacity requirements and of the consent order and impose a Schedule of Compliance. In the event that the consent order is not issued by DEC in the form in which it was agreed to by the six entities and any subsequent negotiations prove unsuccessful, it is not known what relief the DEC will seek through an enforcement action and what the result of such action will be.

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 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. Plaintiff NiMo claims that we have failed to pay retail tariff amounts for utility services commencing on or about June 11, 1999 and continuing to September 18, 2000 and thereafter. 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 the disputes in the action. We cannot make an evaluation of the likelihood of an unfavorable outcome. The cumulative potential loss could exceed $35 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 exceed $35 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, DEQ issued a Part 70 Air Permit modification to Louisiana Generating to construct and operate two 120 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 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. 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.

NRG Sterlington Power, LLC

During 2002, NRG Sterlington conducted a review of the Sterlington Power Facility's Part 70 Air Permit obtained by the facility's former owner and operator, Koch Power, Inc. Koch had outlined a plan to install eight 25 MW capacity turbines to reach a 200 MW capacity limit in the permit. Due to the inability of several units to reach their nameplate capacity, Koch determined that it would need additional units to reach the electric output target. In August 2000, NRG Sterlington acquired the remaining interests in the facility not originally held on a passive basis and sought the transfer of the Part 70 Air Permit along with a modification to incorporate two 17.5 MW turbines installed by Koch and to increase the total number of turbines to ten. The permit modification was issued February 13, 2002. During further review, NRG Sterlington determined that a ninth unit had been installed prior to issuance of the permit modification. In keeping with its environmental policy, it disclosed this matter to DEQ in April, 2002. NRG Sterlington provided to DEQ additional information during July 2002. A Consolidated Compliance Order & Notice of Potential Penalty, No. AE-CN-01-0393, was issued by DEQ on September 10, 2003, wherein DEQ formally alleged that NRG Sterlington did not complete all certification requirements, and installed a ninth unit prior to issuance of its permit modification. We met with DEQ on November 19, 2003 to discuss mitigating circumstances and a settlement has been agreed to between the parties. Under the settlement agreement, without admitting any liability, NRG Sterlington has agreed to pay DEQ the sum of $4,500. The agreement is subject to a public comment period and review by the Louisiana attorney general.

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 intend to respond to the EPA request in an appropriate and cooperative manner. At the present time, we cannot predict the probable outcome in 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 $120 million and Siemens' approximately $45 million in cumulative termination charges. We cannot estimate the likelihood of unfavorable outcomes in these disputes.

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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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. We anticipate that the final report from the expert investigation process will be delivered to the court of arbitration in the last week of March, 2004. After reviewing the final report, the court of arbitration may, if it deems it necessary, require expert testimony on technical and accounting issues, which we anticipate would commence on approximately May 15, 2004. We expect the arbitration panel to issue its decision no later than July 31, 2004. 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 now appears focused on possible efforts by traders to submit false reports to 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 million and $30 million and have agreed to the terms of cease and desist orders. The CFTC has requested additional related information from us and has subpoenaed to appear for testimony a number of our present and former employees. We have sought to cooperate with the CFTC and have submitted materials responsive to the CFTC's requests, while vigorously denying that we engaged in any improper conduct. We cannot at this time predict the outcome or financial impact of this investigation.

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 is 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 disputed claims reserve. We will continue to monitor our obligation as the disputed claims are settled. However, 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 moved 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 make at this time 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 know of no evidence implicating us in the various private plaintiffs' allegations of collusion. We cannot predict the outcome of these cases and investigations at this time.

Note 25 — Cash Flow Information

Detail of supplemental disclosures of cash flow and non-cash investing and financing information was:

	Predecessor Company			Reorganized NRG
	Year Ended December 31,		For the Period January 1– December 5,	For the Period December 6– December 31,
	2001	2002	2003	2003
		(In thousands)		
Interest paid (net of amount capitalized)	$ 385,885	$331,679	$ 182,355	$ 86,874
Income taxes paid/(refunds)	$ 57,055	$ (17,406)	$ 27,064	$ 1,726
Detail of businesses and assets acquired:				
Current assets (including restricted cash)	$ 184,874	$ —	$ —	$ —
Fair value of non-current assets	4,779,530	—	—	—
Liabilities assumed, including deferred taxes	(2,151,287)	—	—	—
Cash paid net of cash acquired	$ 2,813,117	$ —	$ —	$ —

Reorganization Cash Payments and Receipts

Cash Receipts

During the period May 14, 2003 through December 31, 2003, we received $1.1 million of interest income on cash balances. No such amounts were received during the period December 6, 2003 through December 31, 2003.

Cash Payments

Professional fees

During the period May 14, 2003 through December 5, 2003 and December 6, 2003 through December 31, 2003, we made cash payments for professional fees to our financial and legal advisors of $33.5 million and $14.4 million, respectively.

Refinancing activities

We made cash payments of $1.3 billion related to the repayment of NRG Northeast Generating and NRG South Central Generating's debt, including accrued interest upon their emergence from bankruptcy on December 23, 2003 with proceeds from our recently completed corporate level refinancing. We also made cash payments of $19.6 million for a prepayment settlement upon our early payment of the NRG Northeast Generating and NRG South Central Generating debt.

Creditor payments

Upon our emergence from bankruptcy, we made cash payments to our creditors in the amounts of $518.6 million during the period December 6, 2003 through December 31, 2003.

Note 26 — Guarantees

In November 2002, the FASB issued FASB Interpretation No. 45, *"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others."* 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. 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. Additionally, as a result of the downgrades of our unsecured debt ratings, we were required to but failed to post cash collateral in the amount of $71.4 million as of December 31, 2003. At the time of the January 6, 2004 restructuring of the project financing of NRG Peaker Finance Co., LLC, this equity contribution requirement was extinguished and was replaced with a $36.2 million NRG Energy letter of credit, for the benefit of the secured parties in the Peaker financing, as well as other provisions of the restructuring.

As of December 31, 2002, December 6, 2003 and December 31, 2003, our obligations pursuant to our guarantees of the performance, equity and indebtedness obligations of our subsidiaries were as follows:

	Predecessor Company	Reorganized NRG	
Description	December 31 2002	December 6 2003	December 31 2003
		(In thousands)	
Guarantees of subsidiaries	$1,587,022	**$601,859**	**$ 564,114**
Standby letters of credit	110,676	**90,360**	**92,050**
Total guarantees	$1,697,698	**$692,219**	**$ 656,164**

Table of Contents

As of December 6, 2003 and December 31, 2003, the nature and details of our guarantees were as follows:

Project or Subsidiary	Maximum Amount (Dec. 6, 2003)	Maximum Amount (Dec. 31, 2003)	Nature of Guarantee	Expiration Date	Triggering Event
	(In thousands)	(In thousands)			
Astoria/ Arthur Kill	Indeterminate	Indeterminate	Performance under Purchase and Sale Agreement	None stated	Non-performance
Cadillac	$ 773	$ 778	Obligation under Promissory Note	April 15, 2007	Non-payment
Elk River	$ 14,090	$ 11,990	Obligation under Bond Arrangement with NSP	Undetermined	Non-payment of Obligation
Flinders	$ 9,244	$ 9,125	Superannuation (pension) Reserve	September 8, 2012	Credit Agreement Default
Flinders	$ 51,555	$ 52,703	Debt Service Reserve Guarantee	September 8, 2012	Credit Agreement Default
Flinders	$ 59,964	$ 61,601	Plant Removal and Site Remediation Obligation	Undetermined, at end of site lease	Non-performance
Flinders	$ 73,650	$ 75,290	Guarantee of Employee Separation Benefits	None stated	Non-payment
Flinders (Flinders Osborne Trading)	$ 249,281	$ 252,487	Guarantee of Obligation to Purchase Gas	None stated	Non-payment
Flinders (Flinders Osborne Trading)	Indeterminate	Indeterminate	Indemnification of Government Entity for Payment for Power and Fuel	Fourth quarter 2018	Non-payment
Gladstone	$ 23,699	$ 24,346	Payment of Penalties in the Event of an Extraordinary Operational Breach	None stated	Non-performance
Gladstone	Indeterminate	Indeterminate	Obligations under Credit Agreement	March 31, 2009	Non-performance
McClain	$ 1,015	$ 1,015	Obligation to Fund Debt Service Reserve Shortfall	None stated	Non-payment of Subsidiary Obligation
MIBRAG	$ 8,296	$ 8,601	Guarantee of Share Purchase Agreement	None stated	Non-performance
Newport	$ 9,700	$ 7,500	Obligation under Bond Arrangement with NSP	Undetermined	Non-payment of Obligation
PMI	$ 99,093	$ 57,179	Guarantees of NRG Energy, Inc. on behalf of NRG Power Marketing Inc. for various projects	Various	Non-performance
Saguaro	$ 754	$ 754	Guarantee of Tax Indemnity Payments	Undetermined	Non-payment
SLAP I	Indeterminate	Indeterminate	Guarantee of Subscription Agreement in Favor of Scudder Latin American Power I-P LDC and I-C LDC	None stated	Non-performance

Project or Subsidiary	Maximum Amount (Dec. 6, 2003)	Maximum Amount (Dec. 31, 2003)	Nature of Guarantee	Expiration Date	Triggering Event
	(In thousands)	(In thousands)			
West Coast LLC	$ 744	$ 744	Guarantee of Environmental Clean-up Costs	None stated	Non-performance
West Coast LLC	Indeterminate	Indeterminate	Continuing Obligations Under Asset Sales Agreement and Related Contracts (shared with Dynegy)	None stated	Non-performance

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

As of December 6, 2003 and December 31, 2003, the nature and details of our unmet cash collateral obligations were as follows:

Project	Maximum Amount (Dec. 6, 2003)	Maximum Amount (Dec. 31, 2003)	Nature of Collateral Call	Expiration Date	Triggering Event
	(In thousands)	(In thousands)			
NRG Peaker Finance Company LLC	$ 71,472	$ 71,472	Penalty for Early Termination	June 18, 2019	Non-performance

Note 27 — Sales to Significant Customers

Reorganized NRG

For the period from December 6, 2003 through December 31, 2003, we derived approximately 39.0% of our total revenues from majority-owned operations from two customers: NYISO (26.5%) and ISO New England (12.5%).

Predecessor Company

For the period from January 1, 2003 through December 5, 2003, sales to one customer (NYISO) accounted for 33.4% of our total revenues from majority owned operations. During 2002, sales to one customer (NYISO) accounted for 26.0% of our total revenues from majority owned operations in 2002. During 2001, sales to two customers accounted for 35.6% (NYISO) and 18.5% (Connecticut Light and Power Co.) of our total revenues from majority owned operations in 2001.

Note 28 — Jointly Owned Plants

Big Cajun II Unit 3

On March 31, 2000, we acquired a 58% interest in the Big Cajun II, Unit 3 generation plant. Entergy Gulf States 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 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 incurred in proportion to the energy delivered to the owners. Our income statement includes its share of all fixed and variable costs of operating the unit.

Reorganized NRG

Our 58% share of the Property, Plant and Equipment and construction in progress as revalued to fair value upon the adoption of the fresh start provisions of SOP 90-7 at December 6, 2003 and December 31, 2003 was $183.2 million and $183.2 million and corresponding accumulated depreciation and amortization was $0 million and $0.5 million, respectively.

Predecessor Company

Our 58% share of the original cost included in Property, Plant and Equipment and construction in progress at December 31, 2002 was $189.0 million and corresponding accumulated depreciation and amortization was $12.3 million.

Keystone and Conemaugh

In June 2001, we completed the acquisition of an approximately 3.7% interest in both the Keystone and Conemaugh coal-fired generating facilities. The Keystone and Conemaugh facilities are located near Pittsburgh, Pennsylvania and are jointly owned by a consortium of energy companies. We purchased our interest from Conectiv, Inc. Keystone and Conemaugh are operated by GPU Generation, Inc., which sold its assets and operating responsibilities to Sithe Energies. Keystone and Conemaugh both consist of two operational coal-fired steam power units with a combined net output of 1,700 MW, four diesel units with a combined net output of 11 MW and an on-site landfill. The units are operated pursuant to a joint ownership participation and operating agreement. Under this agreement each joint owner is entitled to its ownership ratio of the net available output of the facility. All fixed costs are shared in proportion to the ownership interests. All variable costs are incurred in proportion to the energy delivered to the owners. Our income statement includes our share of all fixed and variable costs of operating the facilities.

Reorganized NRG

Our 3.70% and 3.72% share of the Keystone and Conemaugh facilities original cost included in Property, Plant and Equipment and construction in progress at December 6, 2003 was $60 million and $63 million, respectively. The corresponding accumulated depreciation and amortization at December 6, 2003 for Keystone and Conemaugh was $0 million and $0 million, respectively.

Our 3.70% and 3.72% share of the Keystone and Conemaugh facilities Property, Plant and Equipment and construction in progress as revalued to fair value upon the adoption of the fresh start provisions of SOP 90-7 at December 31, 2003 was $57.9 million and $69.7 million, respectively. The corresponding accumulated depreciation and amortization at December 31, 2003 for Keystone and Conemaugh was $0.2 million and $0.3 million, respectively.

Predecessor Company

Our 3.70% and 3.72% share of the Keystone and Conemaugh facilities original cost included in Property, Plant and Equipment and construction in progress at December 31, 2002 was $57.9 million and $62.8 million, respectively. The corresponding accumulated depreciation and amortization at December 31, 2002 for Keystone and Conemaugh was $3.5 million and $4.1 million, respectively.

Note 29 — Unaudited Quarterly Financial Data

Summarized quarterly unaudited financial data is as follows:

	Predecessor Company					Reorganized NRG
	Quarter Ended 2003			Period Ended 2003		Period Ended 2003
	March 31	June 30	September 30	October 1– December 5	Total through December 5, 2003	December 6– December 31
	(In thousands)					
Operating Revenues	$ 494,947	$ 441,538	$ 570,701	$ 291,201	$ 1,798,387	$ 138,490
Operating Income/(Loss)	(11,958)	(318,595)	(327,565)	3,932,028	3,273,910	16,162
Income/(Loss) From Continuing Operations	(173,136)	(508,518)	(284,544)	3,915,276	2,949,078	11,405
Income/(Loss) on Discontinued Operations net of Income Taxes	160,504	(99,883)	(250)	(243,004)	(182,633)	(380)
Net Income/(Loss)	(12,632)	(608,401)	(284,794)	3,672,272	2,766,445	11,025
Weighted Average Number of Common Shares Outstanding — Basic						100,000
Income From Continuing Operations per Weighted Average Common Share — Basic						$ 0.11
Income From Discontinued Operations per Weighted Average Common Share — Basic						$ —
Net Income per Weighted Average Common Share — Basic						$ 0.11
Weighted Average Number of Common Shares Outstanding — Diluted						100,060
Income From Continuing Operations per Weighted Average Common Share — Diluted						$ 0.11
Income From Discontinued Operations per Weighted Average Common Share — Diluted						$ —
Net Income per Weighted Average Common Share — Diluted						$ 0.11

	Predecessor Company				
	Quarter Ended 2002				
	March 31	June 30	September 30	December 31	Total Year
	(In thousands)				
Operating Revenues	$403,333	$492,023	$ 591,606	$ 451,331	$ 1,938,293
Operating Income/(Loss)	16,025	34,192	(2,365,956)	(67,353)	(2,383,092)
Loss From Continuing Operations	(30,373)	(28,549)	(2,408,852)	(320,678)	(2,788,452)
Income/(Loss) on Discontinued Operations net of Income Taxes	3,910	(12,803)	(646,542)	(20,395)	(675,830)
Net Loss	(26,463)	(41,352)	(3,055,394)	(341,073)	(3,464,282)

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

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

The following condensed consolidating financial information presents the financial information of NRG Energy, the Guarantor Subsidiaries and the Non-Guarantor Subsidiaries in accordance with Rule 3-10 under the Securities and Exchange Commission's

Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the Guarantor Subsidiaries or Non-Guarantor Subsidiaries operated as independent entities.

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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONSOLIDATING STATEMENTS OF OPERATIONS

For the Period December 6, 2003 Through December 31, 2003
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$ 94,455	$ 40,741	$ 3,353	$ (59)	$ 138,490
Operating Costs and Expenses					
Cost of majority-owned operations	64,519	28,734	2,347	(59)	95,541
Depreciation and amortization	7,118	3,931	759	—	11,808
General, administrative and development	7,165	2,803	2,550	—	12,518
Other charges (credits)					
Reorganization items	269	—	2,192	—	2,461
Total operating costs and expenses	79,071	35,468	7,848	(59)	122,328
Operating Income/(Loss)	15,384	5,273	(4,495)	—	16,162
Other Income/(Expense)					
Minority interest in (earnings)/losses of consolidated subsidiaries	—	(134)	—	—	(134)
Equity in earnings of consolidated subsidiaries	3,266	143	16,482	(19,891)	—
Equity in earnings of unconsolidated affiliates	11,007	1,463	1,051	—	13,521
Other income, net	43	(23)	114	(37)	97
Interest expense	(6,417)	(4,719)	(7,803)	37	(18,902)
Total other income/(expense)	7,899	(3,270)	9,844	(19,891)	(5,418)
Income/(Loss) From Continuing Operations Before Income Taxes	23,283	2,003	5,349	(19,891)	10,744
Income Tax Expense/(Benefit)	3,653	1,362	(5,676)	—	(661)
Income/(Loss) From Continuing Operations	19,630	641	11,025	(19,891)	11,405
Income/(Loss) on Discontinued Operations, net of Income Taxes	(4)	(376)	—	—	(380)
Net Income/(Loss)	$ 19,626	$ 265	$ 11,025	$ (19,891)	$ 11,025

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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONSOLIDATING BALANCE SHEETS

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	86,656	58,175	78,263	(956)	222,138
Current deferred income tax	—	2,998	—	(1,148)	1,850
Current assets — discontinued operations	15	119,586	—	—	119,601
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
Decommissioning fund investments	4,809	—	—	—	4,809
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	31,220	26,407	56,504	—	114,131
Non-current assets — discontinued operations	—	623,173	—	—	623,173
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.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONSOLIDATING BALANCE SHEETS — (Continued)

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/(DEFICIT)			
Current Liabilities					
Current portion of long-term debt	$ 30,121	$ 790,078	$ 12,000	$ (30,970)	$ 801,229
Short-term debt	—	19,019	—	—	19,019
Accounts payable — trade	39,369	104,888	14,389	—	158,646
Accounts payable — affiliate	333,722	(221,168)	(102,094)	(7,368)	3,092
Accrued income tax	—	—	(74)	16,169	16,095
Accrued property, sales and other taxes	7,211	13,156	1,934	—	22,301
Accrued salaries, benefits and related costs	9,294	8,949	1,087	—	19,330
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 taxes	509	—	—	(509)	—
Other current liabilities	70,251	13,639	18,971	—	102,861
Current liabilities — discontinued operations	31	114,166	—	—	114,197
Total current liabilities	493,494	1,065,607	490,714	(23,634)	2,026,181
Other Liabilities					
Long-term debt	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/(Deficit)	3,921,385	800,231	2,437,256	(4,721,616)	2,437,256
Total Liabilities and Stockholders' Equity/(Deficit)	$ 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.

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Period December 6, 2003 Through December 31, 2003
Reorganized NRG

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income/(loss)	$ 19,626	$ 265	$ 11,025	$ (19,891)	$ 11,025
Adjustments to reconcile net income/(loss) to net cash provided by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates	1,764	(1,894)	(17,532)	19,891	2,229
Depreciation and amortization	8,255	4,027	759	—	13,041
Amortization of deferred financing costs	—	64	453	—	517
Amortization of debt discount/(premium)	182	1,504	39	—	1,725
Deferred income taxes and investment tax credits	(487)	(212)	(4,117)	1,554	(3,262)
Current tax expense — non cash contribution from members	4,125	(2,901)	—	(1,224)	—
Unrealized (gains)/losses on derivatives	(126)	4,960	(1,060)	—	3,774
Minority interest	134	70	—	—	204
Amortization of out of market power contracts	(16,401)	2,970	—	—	(13,431)
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions					
Accounts receivable, net	12,769	5,040	221	—	18,030
Inventory	3,073	8,041	(60)	—	11,054
Prepayments and other current assets	1,783	1,755	(13,079)	37	(9,504)
Accounts payable	(31,810)	8,672	(17,789)	—	(40,927)
Accounts payable-affiliates	(1,697)	(165)	2,694	—	832
Accrued income taxes	—	—	(877)	(330)	(1,207)
Accrued property and sales taxes	(5,258)	622	46	—	(4,590)
Accrued salaries, benefits, and related costs	2,135	3,511	(2,496)	—	3,150
Accrued interest	(42,350)	(26,140)	4,501	(37)	(64,026)
Other current liabilities	(10,814)	5,635	(505,688)	—	(510,867)
Other assets and liabilities	(162)	(6,911)	431	—	(6,642)
Net Cash Provided (Used) by Operating Activities	(55,259)	8,913	(542,529)	—	(588,875)
Cash Flows from Investing Activities					
Investments in subsidiaries	—	—	(1,530,536)	1,530,536	—
Decrease/(increase) in restricted cash	343,725	31,547	—	—	375,272
Decrease/(increase) in notes receivable	1,501	(11,118)	(1,170)	11,969	1,182
Capital expenditures	(2,977)	(7,583)	—	—	(10,560)
Investments in projects	(2,522)	—	—	—	(2,522)
Net Cash Provided (Used) by Investing Activities	339,727	12,846	(1,531,706)	1,542,505	363,372
Cash Flows from Financing Activities					
Capital contributions from parent	1,530,536	—	—	(1,530,536)	—
Proceeds from issuance of long-term debt	—	—	2,450,000	—	2,450,000
Deferred debt issuance costs	—	(5)	(74,790)	—	(74,795)
Funded letter of credit	—	—	(250,000)	—	(250,000)
Principal payments on long-term debt	(1,713,871)	(6,092)	—	(11,969)	(1,731,932)
Net Cash Provided (Used) by Financing Activities	(183,335)	(6,097)	2,125,210	(1,542,505)	393,273
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	(13,562)	—	—	(13,562)
Change in Cash from Discontinued Operations	—	1,033	—	—	1,033
Net Increase in Cash and Cash Equivalents	101,133	3,133	50,975	—	155,241
Cash and Cash Equivalents at Beginning of Period	194,376	157,301	44,305	—	395,982
Cash and Cash Equivalents at End of Period	$ 295,509	$ 160,434	$ 95,280	$ —	$ 551,223

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONSOLIDATING STATEMENTS OF OPERATIONS

For the Period January 1, 2003 Through December 5, 2003
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$1,230,291	$ 522,467	$ 47,054	$ (1,425)	$ 1,798,387
Operating Costs and Expenses					
Cost of majority-owned operations	991,237	332,858	33,239	(1,425)	1,355,909
Depreciation and amortization	130,491	74,845	13,507	—	218,843
General, administrative and development	65,751	28,815	75,764	—	170,330
Other charges (credits)					
Legal settlement	(9,369)	4,000	468,000	—	462,631
Fresh start reporting adjustments	—	—	(6,570,912)	2,452,276	(4,118,636)
Fresh start reporting adjustments — subsidiaries	—	—	2,452,276	(2,452,276)	—
Reorganization items	30,582	16,644	150,599	—	197,825
Restructuring and impairment charges	247,560	(121,604)	111,619	—	237,575
Total operating costs and expenses	1,456,252	335,558	(3,265,908)	(1,425)	(1,475,523)
Operating Income/(Loss)	(225,961)	186,909	3,312,962	—	3,273,910
Other Income (Expense)					
Minority interest in (earnings)/losses of consolidated subsidiaries	—	—	—	—	—
Equity in earnings of consolidated subsidiaries	104,905	—	(18,356)	(86,549)	—
Equity in earnings of unconsolidated affiliates	107,254	64,850	(1,203)	—	170,901
Write downs and losses on sales of equity method investments	(16,285)	(125,945)	(4,894)	—	(147,124)
Other income, net	5,087	30,470	(15,429)	(919)	19,209
Interest expense	(135,837)	(83,135)	(111,836)	919	(329,889)
Total other income/(expense)	65,124	(113,760)	(151,718)	(86,549)	(286,903)
Income/(Loss) From Continuing Operations Before Income Taxes	(160,837)	73,149	3,161,244	(86,549)	2,987,007
Income Tax Expense/(Benefit)	(107,292)	(10,791)	156,012	—	37,929
Income/(Loss) From Continuing Operations	(53,545)	83,940	3,005,232	(86,549)	2,949,078
Income/(Loss) on Discontinued Operations, net of Income Taxes	(25,920)	82,074	(238,787)	—	(182,633)
Net Income/(Loss)	$ (79,465)	$ 166,014	$ 2,766,445	$ (86,549)	$ 2,766,445

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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONSOLIDATING BALANCE SHEETS

December 6, 2003
Reorganized Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
ASSETS					
Current Assets					
Cash and cash equivalents	$ 194,376	$ 157,301	$ 44,305	$ —	$ 395,982
Restricted cash	348,023	145,024	—	—	493,047
Accounts receivable-trade, net	133,180	66,719	13,580	—	213,479
Xcel Energy settlement receivable	—	—	640,000	—	640,000
Current portion of notes receivable	1,500	311,559	30,274	(276,705)	66,628
Inventory	167,926	27,136	1,174	—	196,236
Derivative instruments valuation	161	—	—	—	161
Prepayments and other current assets	88,437	57,839	65,184	(919)	210,541
Current deferred income tax	—	2,822	—	(2,822)	—
Current assets — discontinued operations	(1,058)	129,042	(1,408)	—	126,576
Total current assets	932,545	897,442	793,109	(280,446)	2,342,650
Property, Plant and Equipment					
In service	2,288,119	1,553,540	35,136	—	3,876,795
Under construction	17,888	113,977	138	—	132,003
Total property, plant and equipment	2,306,007	1,667,517	35,274	—	4,008,798
Less accumulated depreciation	—	—	—	—	—
Net property, plant and equipment	2,306,007	1,667,517	35,274	—	4,008,798
Other Assets					
Investment in subsidiaries	604,809	—	2,327,927	(2,932,736)	—
Equity investments in affiliates	405,860	316,509	11,493	—	733,862
Notes receivable, less current portion — affiliates	9,419	322,366	—	(206,134)	125,651
Notes receivable, less current portion	385,517	204,124	1,290	84,000	674,931
Decommissioning fund investments	4,787	—	—	—	4,787
Deferred income taxes	57,887	—	—	(57,887)	—
Intangible assets, net	414,258	70,410	—	—	484,668
Derivative instruments valuation	—	66,442	—	—	66,442
Other assets	31,215	21,025	56,504	—	108,744
Non-current assets — discontinued operations	—	616,796	—	—	616,796
Total other assets	1,913,752	1,617,672	2,397,214	(3,112,757)	2,815,881
Total Assets	$5,152,304	$4,182,631	$ 3,225,597	$(3,393,203)	$9,167,329

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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONSOLIDATING BALANCE SHEETS — (Continued)

December 6, 2003
Reorganized Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
LIABILITIES AND STOCKHOLDERS' EQUITY/(DEFICIT)					
Current Liabilities					
Current portion of long-term debt	$1,743,810	$ 782,944	—	$ (30,000)	$2,496,754
Short-term debt	—	18,645	—	—	18,645
Accounts payable — trade	71,163	99,061	32,178	—	202,402
Accounts payable — affiliate	334,354	(208,464)	(105,157)	(7,368)	13,365
Accrued income tax	—	—	803	15,628	16,431
Accrued property, sales and other taxes	12,470	13,436	1,888	—	27,794
Accrued salaries, benefits and related costs	8,208	4,587	3,923	—	16,718
Accrued interest	44,907	31,785	—	(919)	75,773
Derivative instruments valuation	95	—	—	—	95
Creditor pool obligation	3,360	—	1,036,640	—	1,040,000
Other bankruptcy settlement	—	220,000	—	—	220,000
Current deferred income taxes	498	—	—	(498)	—
Other current liabilities	92,805	15,951	28,019	—	136,775
Current liabilities — discontinued operations	46	112,642	—	—	112,688
Total current liabilities	2,311,716	1,090,587	998,294	(23,157)	4,377,440
Other Liabilities					
Long-term debt	10,999	1,312,875	8,651	(452,839)	879,686
Deferred income taxes	—	149,172	(212,196)	207,712	144,688
Postretirement and other benefit obligations	79,671	13,580	11,461	—	104,712
Derivative instruments valuation	—	155,709	—	—	155,709
Other long-term obligations	402,362	118,933	15,387	—	536,682
Non-current liabilities — discontinued operations	—	559,560	—	—	559,560
Total non-current liabilities	493,032	2,309,829	(176,697)	(245,127)	2,381,037
Total liabilities	2,804,748	3,400,416	821,597	(268,284)	6,758,477
Minority interest	—	4,852	—	—	4,852
Commitments and Contingencies					
Stockholders' Equity/(Deficit)	2,347,556	777,363	2,404,000	(3,124,919)	2,404,000
Total Liabilities and Stockholders' Equity/(Deficit)	$5,152,304	$4,182,631	$ 3,225,597	$(3,393,203)	$9,167,329

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONSOLIDATING STATEMENTS OF CASH FLOW

For the Period January 1, 2003 Through December 5, 2003
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income/(loss)	$ (79,465)	$ 166,014	$ 2,766,445	$ (86,549)	$ 2,766,445
Adjustments to reconcile net income/(loss) to net cash provided by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates	(95,360)	(53,400)	20,739	86,549	(41,472)
Depreciation and amortization	131,399	111,794	13,507	—	256,700
Amortization of deferred financing costs	6,676	7,016	3,948	—	17,640
Write downs and losses on sales of equity method investments	16,284	130,654	—	—	146,938
Deferred income taxes and investment tax credits	(123,237)	(36,015)	181,544	(24,185)	(1,893)
Current tax expense — non cash contribution from members	(17,149)	(54,148)	—	71,297	—
Unrealized (gains)/losses on derivatives	(12,246)	(75,310)	29,540	23,400	(34,616)
Minority interest	—	2,177	—	—	2,177
Restructuring & impairment charges	273,138	93,516	41,723	—	408,377
Fresh start reporting adjustments	—	—	(3,895,541)	—	(3,895,541)
Gain on sale of discontinued operations	3,180	(198,666)	9,155	—	(186,331)
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions					
Accounts receivable, net	59,168	(5,552)	(25,355)	—	28,261
Inventory	25,713	(14,512)	2,927	—	14,128
Prepayments and other current assets	(30,388)	8,599	(15,942)	919	(36,812)
Accounts payable	116,452	(57,004)	634,215	—	693,663
Accounts payable-affiliates	189,204	(52,324)	(20,346)	(161,551)	(45,017)
Accrued income taxes	—	—	68,356	(47,112)	21,244
Accrued property and sales taxes	(2,015)	(625)	(519)	—	(3,159)
Accrued salaries, benefits, and related costs	(41,037)	92,331	(10,604)	—	40,690
Accrued interest	(14,865)	54,773	119,592	(919)	158,581
Other current liabilities	29,631	46,438	(98,866)	—	(22,797)
Other assets and liabilities	15,940	(68,051)	3,414	—	(48,697)
Net Cash Provided (Used) by Operating Activities	451,023	97,705	(172,068)	(138,151)	238,509
Cash Flows from Investing Activities					
Investment in subsidiaries	—	—	129,351	(129,351)	—
Proceeds from sale of discontinued operations	—	18,612	—	—	18,612
Proceeds from sale of investments	—	107,174	—	—	107,174
Proceeds from sale of turbines	—	—	70,717	—	70,717
(Increase) in trust funds	(13,971)	—	—	—	(13,971)
Decrease/(increase) in restricted cash	(197,692)	(54,803)	—	—	(252,495)
Decrease/(increase) in notes receivable	98,064	42,493	285	(142,495)	(1,653)
Capital expenditures	(55,833)	(6,450)	(51,219)	—	(113,502)
Investments in projects	(3,672)	(5,259)	8,370	—	(561)
Net Cash Provided (Used) by Investing Activities	(173,104)	101,767	157,504	(271,846)	(185,679)
Cash Flows from Financing Activities					
Capital contributions from parent	(135,251)	(132,251)	—	267,502	—
Proceeds from issuance of long-term debt	—	39,988	—	—	39,988
Deferred debt issuance costs	(7,640)	(447)	(10,453)	—	(18,540)
Principal payments on long-term debt	(4,055)	(189,832)	—	142,495	(51,392)
Net Cash Provided (Used) by Financing Activities	(146,946)	(282,542)	(10,453)	409,997	(29,944)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	(22,276)	—	—	(22,276)
Change in Cash from Discontinued Operations	—	34,512	—	—	34,512
Net Increase in Cash and Cash Equivalents	130,973	(70,834)	(25,017)	—	35,122
Cash and Cash Equivalents at Beginning of Period	63,403	228,135	69,322	—	360,860

Cash and Cash Equivalents at End of Period	$ 194,376	$ 157,301	$ 44,305	$ —	$ 395,982

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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONSOLIDATING STATEMENTS OF OPERATIONS

For the Year Ended December 31, 2002
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$1,376,586	$ 510,434	$ 55,492	$ (4,219)	$ 1,938,293
Operating Costs and Expenses					
Cost of majority-owned operations	918,941	345,133	72,750	(4,378)	1,332,446
Depreciation and amortization	126,258	69,512	11,257	—	207,027
General, administrative and development	49,759	53,252	115,682	159	218,852
Other charges (credits)					
Restructuring and impairment charges	108,236	2,091,845	362,979	—	2,563,060
Total operating costs and expenses	1,203,194	2,559,742	562,668	(4,219)	4,321,385
Operating Income/ (Loss)	173,392	(2,049,308)	(507,176)	—	(2,383,092)
Other Income (Expense)					
Minority interest in (earnings)/ losses of consolidated subsidiaries	—	—	—	—	—
Equity in earnings of consolidated subsidiaries	(690,627)	(454)	(2,944,968)	3,636,049	—
Equity in earnings of unconsolidated affiliates	17,786	50,398	812	—	68,996
Write downs and losses on sales of equity method investments	(16,255)	(182,035)	(2,182)	—	(200,472)
Other income, net	9,648	9,221	(4,127)	(3,311)	11,431
Interest expense	(142,775)	(115,741)	(196,977)	3,311	(452,182)
Total other income/ (expense)	(822,223)	(238,611)	(3,147,442)	3,636,049	(572,227)
Income/ (Loss) From Continuing Operations Before Income Taxes	(648,831)	(2,287,919)	(3,654,618)	3,636,049	(2,955,319)
Income Tax Expense/ (Benefit)	(1,905)	25,374	(190,336)	—	(166,867)
Income/ (Loss) From Continuing Operations	(646,926)	(2,313,293)	(3,464,282)	3,636,049	(2,788,452)
Income/ (Loss) on Discontinued Operations, net of Income Taxes	(25,328)	(650,502)	—	—	(675,830)
Net Income/ (Loss)	$ (672,254)	$(2,963,795)	$(3,464,282)	$ 3,636,049	$(3,464,282)

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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONSOLIDATING BALANCE SHEETS

December 31, 2002
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
		ASSETS			
Current Assets					
Cash and cash equivalents	$ 63,403	$ 228,135	$ 69,322	$ —	$ 360,860
Restricted cash	150,331	61,635	—	—	211,966
Accounts receivable-trade, net	192,060	60,108	5,452	—	257,620
Current portion of notes receivable — affiliates	—	2,442	—	—	2,442
Current portion of notes receivable	479,284	84,319	—	(511,334)	52,269
Income tax receivable	—	—	68,356	(59,968)	8,388
Inventory	226,951	22,485	4,576	—	254,012
Derivative instruments valuation	28,761	—	30	—	28,791
Prepayments and other current assets	76,643	27,052	29,940	—	133,635
Current deferred income tax	12,359	(2,557)	—	(9,802)	—
Current assets — discontinued operations	(1,349)	239,863	—	—	238,514
Total current assets	1,228,443	723,482	177,676	(581,104)	1,548,497
Property, Plant and Equipment					
In service	3,416,388	2,183,325	92,306	—	5,692,019
Under construction	64,407	486,560	60,224	—	611,191
Total property, plant and equipment	3,480,795	2,669,885	152,530	—	6,303,210
Less accumulated depreciation	(288,456)	(168,876)	(44,603)	—	(501,935)
Net property, plant and equipment	3,192,339	2,501,009	107,927	—	5,801,275
Other Assets					
Investment in subsidiaries	111,400	—	2,535,759	(2,647,159)	—
Equity investments in affiliates	530,829	320,716	32,718	—	884,263
Notes receivable, less current portion — affiliates	9,538	142,014	—	—	151,552
Notes receivable, less current portion	5,678	776,905	31,849	(30,000)	784,432
Decommissioning fund investments	4,617	—	—	—	4,617
Intangible assets, net	25,349	48,634	1,148	—	75,131
Debt issuance costs, net	24,582	81,582	22,996	—	129,160
Derivative instruments valuation	9,601	48,460	32,705	—	90,766
Other assets	4,893	752	8,519	—	14,164
Non-current assets — discontinued operations	31,085	1,381,909	—	—	1,412,994
Total other assets	757,572	2,800,972	2,665,694	(2,677,159)	3,547,079
Total Assets	$5,178,354	$6,025,463	$2,951,297	$(3,258,263)	$10,896,851

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONSOLIDATING BALANCE SHEETS — (Continued)

December 31, 2002
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
LIABILITIES AND STOCKHOLDERS' EQUITY/(DEFICIT)					
Current Liabilities					
Current portion of long-term debt	$1,716,451	$2,286,403	$2,998,280	$ —	$ 7,001,134
Revolving line of credit	—	—	1,000,000	—	1,000,000
Short-term debt	—	15,849	14,215	—	30,064
Accounts payable — trade	85,343	300,960	153,693	—	539,996
Accounts payable — affiliate	486,161	408,723	(831,931)	(7,368)	55,585
Accrued income tax	—	—	—	—	—
Accrued property, sales and other taxes	2,015	21,737	519	—	24,271
Accrued salaries, benefits and related costs	5,709	7,950	3,185	—	16,844
Accrued interest	59,674	37,261	180,181	—	277,116
Derivative instruments valuation	13,334	13	92	—	13,439
Current deferred income taxes	—	—	—	—	—
Other current liabilities	8,737	12,876	83,728	—	105,341
Current liabilities — discontinued operations	8,512	757,109	—	—	765,621
Total current liabilities	2,385,936	3,848,881	3,601,962	(7,368)	9,829,411
Other Liabilities					
Long-term debt	65,050	1,341,798	—	(625,334)	781,514
Deferred income taxes	(137,308)	(111,446)	(4,424)	328,064	74,886
Postretirement and other benefit obligations	35,678	11,479	20,338	—	67,495
Derivative instruments valuation	9,467	81,311	261	—	91,039
Other long-term obligations	38,208	78,027	29,359	—	145,594
Non-current liabilities — discontinued operations	—	602,600	—	—	602,600
Total non-current liabilities	11,095	2,003,769	45,534	(297,270)	1,763,128
Total liabilities	2,397,031	5,852,650	3,647,496	(304,638)	11,592,539
Minority interest	—	511	—	—	511
Commitments and Contingencies Stockholders' Equity/(Deficit)	2,781,323	172,302	(696,199)	(2,953,625)	(696,199)
Total Liabilities and Stockholders' Equity/(Deficit)	$5,178,354	$6,025,463	$2,951,297	$(3,258,263)	$10,896,851

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

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2002
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income/(loss)	$ (672,254)	$ (2,963,795)	$ (3,464,282)	$ 3,636,049	$ (3,464,282)
Adjustments to reconcile net income/(loss) to net cash provided by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates	689,451	(19,810)	2,944,156	(3,636,049)	(22,252)
Depreciation and amortization	131,876	143,491	11,256	—	286,623
Amortization of deferred financing costs	3,450	13,046	11,871	—	28,367
Write downs and losses on sales of equity method Investments	11,975	182,035	2,182	—	196,192
Deferred income taxes and investment tax credits	(44,442)	(9,847)	(130,273)	(45,572)	(230,134)
Current tax expense — non cash contribution from members	3,874	(27,477)	—	23,603	—
Unrealized (gains)/losses on derivatives	(18,439)	47,422	(31,726)	—	(2,743)
Minority interest	—	(19,325)	—	—	(19,325)
Amortization of out of market power contracts	(89,415)	—	—	—	(89,415)
Restructuring & impairment charges	109,207	2,760,390	274,912	—	3,144,509
Gain on sale of discontinued operations	—	(2,814)	—	—	(2,814)
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions					
Accounts receivable, net	(72,106)	29,883	26,736	—	(15,487)
Accounts receivable-affiliates	1,100	1,171	—	—	2,271
Inventory	49,795	(7,185)	(14)	—	42,596
Prepayments and other current assets	(44,999)	13,412	(26,781)	—	(58,368)
Accounts payable	(38,789)	180,682	137,007	—	278,900
Accounts payable-affiliates	358,032	417,072	(728,193)	138	47,049
Accrued income taxes	—	—	22,168	21,969	44,137
Accrued property and sales taxes	(7,678)	34,634	525	—	27,481
Accrued salaries, benefits, and related costs	(8,253)	2,708	(19,367)	—	(24,912)
Accrued interest	33,985	40,488	128,761	—	203,234
Other current liabilities	7,516	(8,560)	48,736	—	47,692
Other assets and liabilities	(4,428)	10,818	4,333	—	10,723
Net Cash Provided (Used) by Operating Activities	399,458	818,439	(787,993)	138	430,042
Cash Flows from Investing Activities					
Acquisitions, net of liabilities assumed	—	—	—	—	—
Proceeds from sale of discontinued operations	—	160,791	—	—	160,791
Proceeds from sale of investments	—	68,517	—	—	68,517
Proceeds from sale of turbines	—	—	—	—	—
(Increase) in trust funds	—	—	—	—	—
Decrease/(increase) in restricted cash	(138,798)	(109,004)	50,000	—	(197,802)
Decrease/(increase) in notes receivable	(28,247)	(230,733)	(29,728)	79,464	(209,244)
Capital expenditures	(92,003)	(1,349,163)	1,433	—	(1,439,733)
Investments in projects	(36,047)	(25,896)	(2,053)	—	(63,996)
Investment in subsidiaries	(27,967)	—	(145,732)	173,699	—
Distributions from subsidiaries	—	—	216,751	(216,751)	—
Net Cash Provided (Used) by Investing Activities	(323,062)	(1,485,488)	90,671	36,412	(1,681,467)
Cash Flows from Financing Activities					
Net borrowings under line of credit agreement	(40,000)	—	830,000	—	790,000
Proceeds from issuance of stock	—	—	4,065	—	4,065
Proceeds from issuance of corporate units (warrants)	—	—	—	—	—
Proceeds from issuance of short term debt	—	—	—	—	—
Capital contributions from parent	81,427	92,487	500,000	(173,914)	500,000
Distributions to parent	—	(216,751)	—	216,751	—
Proceeds from issuance of long-term debt	37,869	963,000	165,288	(79,387)	1,086,770
Principal payments on long-term debt	(99,331)	(92,174)	(740,000)	—	(931,505)
Net Cash Provided (Used) by Financing Activities	(20,035)	746,562	759,353	(36,550)	1,449,330
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(1,092)	20,426	5,616	—	24,950

Change in Cash from Discontinued Operations	—	51,267	—	—	51,267
Net Increase in Cash and Cash Equivalents	55,269	151,206	67,647	—	274,122
Cash and Cash Equivalents at Beginning of Period	8,134	76,929	1,675	—	86,738
Cash and Cash Equivalents at End of Period	$ 63,403	$ 228,135	$ 69,322	$ —	$ 360,860

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

Table of Contents

CONSOLIDATING STATEMENTS OF OPERATIONS

For the Year Ended December 31, 2001
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Operating Revenues					
Revenues from majority-owned operations	$1,639,596	$ 416,015	$ 39,525	$ (9,786)	$2,085,350
Operating Costs and Expenses					
Cost of majority-owned operations	1,066,107	319,042	125	(9,884)	1,375,390
Depreciation and amortization	102,823	32,577	5,576	—	140,976
General, administrative and development	44,083	33,215	109,769	98	187,165
Total operating costs and expenses	1,213,013	384,834	115,470	(9,786)	1,703,531
Operating Income/ (Loss)	426,583	31,181	(75,945)	—	381,819
Other Income (Expense)					
Minority interest in (earnings)/ losses of consolidated subsidiaries	—	—	—	—	—
Equity earnings in consolidated subsidiaries	100,330	(323)	409,872	(509,879)	—
Equity in earnings of unconsolidated affiliates	143,141	68,117	(1,226)	—	210,032
Write downs and losses on sales of equity method investments	—	—	—	—	—
Other income, net	16,718	5,753	3,349	(2,837)	22,983
Interest expense	(144,897)	(20,622)	(201,429)	2,837	(364,111)
Total other income/(expense)	115,292	52,925	210,566	(509,879)	(131,096)
Income/ (Loss) From Continuing Operations Before Income Taxes	541,875	84,106	134,621	(509,879)	250,723
Income Tax Expense/(Benefit)	140,691	30,113	(130,583)	—	40,221
Income/ (Loss) From Continuing Operations	401,184	53,993	265,204	(509,879)	210,502
Income/ (Loss) on Discontinued Operations, net of Income Taxes	120	54,582	—	—	54,702
Net Income/(Loss)	$ 401,304	$ 108,575	$ 265,204	$ (509,879)	$ 265,204

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

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

CONSOLIDATING STATEMENTS OF CASH FLOWS

For the Year Ended December 31, 2001
Predecessor Company

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	NRG Energy, Inc. (Note Issuer)	Eliminations(1)	Consolidated Balance
			(In thousands)		
Cash Flows from Operating Activities					
Net income/(loss)	$ 401,304	$ 108,575	$ 265,204	$ (509,879)	$ 265,204
Adjustments to reconcile net income/(loss) to net cash provided by operating activities					
Distributions in excess of (less than) equity earnings of unconsolidated affiliates	(100,199)	(119,002)	(271,447)	371,646	(119,002)
Depreciation and amortization	106,995	99,922	5,576	—	212,493
Amortization of deferred financing costs	1,571	2,140	6,957	—	10,668
Deferred income taxes and investment tax credits	24,908	8,379	(57,717)	69,986	45,556
Current tax expense — non cash contribution from members	99,022	(12,221)	—	(86,801)	—
Unrealized (gains)/losses on derivatives	31,711	(3,218)	(41,750)	—	(13,257)
Minority interest	—	6,564	—	—	6,564
Amortization of out of market power contracts	(54,963)	—	—	—	(54,963)
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions					
Accounts receivable, net	98,003	1,506	(9,986)	—	89,523
Inventory	(102,424)	(6,146)	(2,561)	—	(111,131)
Prepayments and other current assets	(5,593)	(29,040)	(1,897)	—	(36,530)
Accounts payable	3,086	(12,374)	4,776	—	(4,512)
Accounts payable-affiliates	(119,294)	(213,323)	132,946	204,660	4,989
Accrued income taxes	—	—	(91,947)	16,815	(75,132)
Accrued property and sales taxes	5,128	(1,061)	(13)	—	4,054
Accrued salaries, benefits, and related costs	7,388	3,598	4,799	—	15,785
Accrued interest	1,276	6,299	28,062	—	35,637
Other current liabilities	46,796	10,153	25,805	—	82,754
Other assets and liabilities	(49,596)	(25,093)	(7,997)	—	(82,686)
Net Cash Provided (Used) by Operating Activities	395,119	(174,342)	(11,190)	66,427	276,014
Cash Flows from Investing Activities					
Acquisitions, net of liabilities assumed	(649,538)	—	(2,163,579)	—	(2,813,117)
Proceeds from sale of investments	—	4,063	—	—	4,063
Decrease/(increase) in restricted cash	(5,037)	(44,670)	(50,000)	—	(99,707)
Decrease/(increase) in notes receivable	36,073	16,769	506	(8,257)	45,091
Capital expenditures	(124,175)	(928,495)	(269,460)	—	(1,322,130)
Investments in projects	(124,850)	34,412	6,947	(66,350)	(149,841)
Investments in subsidiaries	(24,050)	—	(626,436)	650,486	—
Distributions from subsidiaries	—	—	418,000	(418,000)	—
Net Cash Provided (Used) by Investing Activities	(891,577)	(917,921)	(2,684,022)	157,879	(4,335,641)
Cash Flows from Financing Activities					
Net borrowings under line of credit agreement	40,000	—	162,000	—	202,000
Proceeds from issuance of stock	—	—	475,464	—	475,464
Proceeds from issuance of corporate units (warrants)	—	—	4,080	—	4,080
Proceeds from issuance of short term debt	—	22,156	600,000	—	622,156
Capital contributions from parent	551,424	99,062	—	(650,486)	—
Distributions to parent	(418,000)	—	—	418,000	—
Proceeds from issuance of long-term debt	445,397	1,342,166	1,472,274	8,180	3,268,017
Principal payments on long-term debt	(118,480)	(279,736)	(19,955)	—	(418,171)
Net Cash Provided (Used) by Financing Activities	500,341	1,183,648	2,693,863	(224,306)	4,153,546
Effect of Exchange Rate Changes on Cash and Cash Equivalents	922	(3,977)	—	—	(3,055)
Change in Cash from Discontinued Operations	—	(40,873)	—	—	(40,873)
Net Increase (Decrease) in Cash and Cash Equivalents	4,805	46,535	(1,349)	—	49,991
Cash and Cash Equivalents at Beginning of Period	3,329	30,394	3,024	—	36,747
Cash and Cash Equivalents at End of Period	$ 8,134	$ 76,929	$ 1,675	$ —	$ 86,738

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

Note 31 — Subsequent Event

On May 13, 2004 we completed the sale of our 63% interest in Hsin Yu to Asia Pacific Energy Development Co., Ltd or "APED," which resulted in net cash proceeds of approximately $1.0 million and a net gain of approximately $10.0 million.

LSP Energy — Batesville — In August, 2004 we completed the sale of our 100 percent interest in an 837 megawatt generating plant in Batesville, Mississippi to Complete Energy Partners, LLC. We realized cash proceeds of $27.6 million.

Kendall — In December, 2004 we completed the sale of Kendall, a 1,160 megawatt generating plant to an affiliate of LS Power Associates, L.P. We have the right to reacquire a 40% interest in the plant within a 10-year period, for a nominal amount, therefore the transaction is being treated as a partial sale for accounting purposes. We realized cash proceeds of $1.0 million and a net loss of approximately $24.5 million, which was recorded in the third quarter of 2004.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON

FINANCIAL STATEMENT SCHEDULES

To the Board of Directors and Stockholders of NRG Energy, Inc.:

Our audits of the consolidated financial statements referred to in our report dated March 10, 2004, except as to Notes 6, 20, 30 and 31, which are as of December 6, 2004, appearing in this Annual Report on Form 10-K also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Annual Report on Form 10-K Amendment No. 3. In our opinion, this financial statement schedule for the period from December 6, 2003 to December 31, 2003 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota

March 10, 2004, except as to
Notes 6, 20, 30 and 31,
which are as of December 6, 2004.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON

FINANCIAL STATEMENT SCHEDULES

To the Board of Directors and Stockholders of NRG Energy, Inc.:

Our audits of the consolidated financial statements referred to in our report dated March 10, 2004, except as to Notes 6, 20, 30 and 31, which are as of December 6, 2004, appearing in this Annual Report on Form 10-K also included an audit of the financial statement schedule listed in Item 15(a)(2) of this Annual Report on Form 10-K Amendment No. 3. In our opinion, this financial statement schedule for the period from January 1, 2003 to December 5, 2003 and for the two years ended December 31, 2002, present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota

March 10, 2004, except as to
Notes 6, 20, 30 and 31,
which are as of December 6, 2004.

NRG ENERGY, INC.

SCHEDULE II. VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2003, 2002 and 2001

Column A	Column B	Column C		Column D	Column E
		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
		(In thousands)			
Allowance for doubtful accounts, deducted from accounts receivable in the balance sheet:					
Predecessor Company					
Year ended December 31, 2001	$21,199	$ —	$ —	$ (7,565)	$13,634
Year ended December 31, 2002	13,634	4,529	—	—	18,163
January 1 — December 5, 2003	18,163	15,576	—	(33,739)	—*
Reorganized NRG December 6 — December 31, 2003	$ —	$ —	$ —	$ —	$ —

* December 6, 2003 — Fresh Start Balance

		Additions			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other	Deductions	Balance at End of Period
		(In thousands)			
Income tax valuation allowance, deducted from deferred tax assets in the balance sheet:					
Predecessor Company					
Year ended December 31, 2001	$ 50,057	$ 21,389	$ —	$ —	$ 71,446
Year ended December 31, 2002	71,446	1,006,540	92,315	—	1,170,301
January 1 — December 5, 2003	1,170,301	71,315	—	—	1,241,616*
Reorganized NRG December 6 — December 31, 2003	$1,241,616	$ (515)	$ —	$ —	$1,241,101

* December 6, 2003 — Fresh Start Balance

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: December 7, 2004

EXHIBIT INDEX

3.1	Amended and Restated Certificate of Incorporation.(2)
3.2	Amended and Restated By-Laws.(8)
4.1	Indenture dated as of December 23, 2003 by and among NRG Energy, Inc., certain subsidiaries of NRG Energy, Inc. and Law Debenture Trust Company of New York, as Trustee, re: NRG Energy, Inc.'s 8% Second Priority Senior Secured Notes due 2013.(2)
4.2	Purchase Agreement dated as of December 17, 2003 by and among NRG Energy, Inc., as Issuer, certain subsidiaries of NRG Energy, Inc., as guarantors, and Lehman Brothers, Inc., Credit Suisse First Boston LLC, Citigroup Global Markets Inc. and Deutsche Bank Securities, Inc., as Initial Purchasers, re: $1,250,000,000 8% Second Priority Senior Secured Notes due 2013.(2)
4.3	Registration Rights Agreement dated as of December 23, 2003 by and among NRG Energy, Inc,.as Issuer, certain subsidiaries of NRG Energy, Inc., as Guarantors, and Lehman Brothers Inc., Credit Suisse First Boston LLC, Citigroup Global Markets Inc. and Deutsche Bank Securities, Inc., as Initial Purchasers.(2)
4.4	Purchase Agreement dated as of January 21, 2003 by and among NRG Energy, as Issuer, certain subsidiaries of NRG Energy, Inc., as Guarantors, and Credit Suisse First Boston LLC and Lehman Brothers, Inc., as Initial Purchasers, re: $475,000,000 8% Second Priority Senior Secured Notes due 2013.(2)
4.5	Registration Rights Agreement dated as of January 28, 2004 by and among NRG Energy, Inc., as Issuer, certain subsidiaries of NRG Energy, Inc., as Guarantors, and Credit Suisse First Boston LLC and Lehman Brothers, Inc., as Initial Purchasers.(2)
4.6	$1,450,000,000 Credit Agreement dated as of December 23, 2003 among NRG Energy, Inc. NRG Power Marketing, Inc., the Lenders party thereto, and Credit Suisse First Boston, acting through its Cayman Islands Branch, and Lehman Brothers Inc., as joint lead book runners and joint lead arrangers, Credit Suisse First Boston, acting though its Cayman Islands Branch, as administrative agent, General Electric Capital Corporation, as revolver agent, and Lehman Commercial Paper Inc., as syndication agent.(2)
4.7	Guarantee and Collateral Agreement made by NRG Energy, Inc., NRG Power Marketing, Inc. and certain of the subsidiaries of NRG Energy, Inc. in favor of Deutsche Bank Trust Company Americas, as Collateral Trustee, Credit Suisse First Boston, acting through its Cayman Islands Branch, as Administrative Agent, and Law Debenture Trust Company of New York, as Trustee.(2)
4.8	Collateral Trust Agreement dated as of December 23, 2003 among NRG Energy, Inc., NRG Power Marketing, Inc., the Guarantors from time to time party hereto, Credit Suisse First Boston, acting through its Cayman Islands Branch, as Administrative Agent, Law Debenture Trust Company of New York, as Trustee, and Deutsche Bank Trust Company Americas, as Collateral Trustee.(2)
4.9	Amended and Restated Common Agreement among XL Capital Assurance Inc., Goldman Sachs Mitsui Marine Derivative Products, L.P., Law Debenture Trust Company of New York, as Trustee, The Bank of New York, as Collateral Agent, NRG Peaker Finance Company LLC and each Project Company Party thereto dated as of January 6, 2004, together with Annex A to the Common Agreement.(2)
4.10	Amended and Restated Security Deposit Agreement among NRG Peaker Finance Company, LLC and each Project Company party thereto, and the Bank of New York, as Collateral Agent and Depositary Agent, dated as of January 6, 2004.(2)
4.11	NRG Parent Agreement by NRG Energy, Inc. in favor of the Bank of New York, as Collateral Agent, dated as of January 6, 2004.(2)
4.12	Indenture dated June 18, 2002, between NRG Peaker Finance Company LLC, as Issuer, Bayou Cove Peaking Power LLC, big Cajun I Peaking Power LLC, NRG Rockford LLC, NRG Rockford II LLC and Sterlington Power LLC, as Guarantors, XL Capital Assurance Inc., as Insurer, and Law Debenture Trust Company, as Successor Trustee to the Bank of New York.(4)
10.1*	Employment Agreement dated November 10, 2003 between NRG Energy, Inc. and David Crane.(2)

10.2	Note Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc. and each of the purchasers named therein.(5)
10.3	Master Shelf and Revolving Credit Agreement, dated August 20, 1993, between NRG Energy, Inc., Energy Center, Inc., The Prudential Insurance Registrants of America and each Prudential Affiliate, which becomes party thereto.(5)
10.4	Asset Sales Agreement, dated December 23, 1998, between NRG Energy, Inc., and Niagara Mohawk Power Corporation.(6)
10.5	Generating Plant and Gas Turbine Asset Purchase and Sale Agreement for the Arthur Kill generating plants and Astoria gas turbines, dated January 27, 1999, between NRG Energy and Consolidated Edison Company of New York, Inc.(6)
10.6	Amendment to the Asset Sales Agreement, dated June 11, 1999, between NRG Energy, Inc., and Niagara Mohawk Power Corporation.(6)
10.7	Third Amended Joint Plan of Reorganization of NRG Energy, Inc., NRG Power Marketing, Inc., NRG Capital LLC, NRG Finance Company I LLC, and NRGenerating Holdings (No. 23) B.V.(7)
10.8	First Amended Joint Plan of Reorganization of NRG Northeast Generating LLC (and certain of its subsidiaries), NRG South Central Generating (and certain of its subsidiaries) and Berrians I Gas Turbine Power LLC.(7)
10.9*	Key Executive Retention, Restructuring Bonus and Severance Agreement between NRG Energy, Inc. and Scott J. Davido dated July 1, 2003.(2)
10.10*	Severance Agreement between NRG Energy, Inc. and Ershel Redd Jr. dated January 30, 2003.(4)
10.11*	Severance Agreement between NRG Energy and William Pieper dated March 1, 2003.(2)
10.12*	Severance Agreement between NRG Energy, Inc. and George Schaefer dated December 18, 2002.(4)
10.13*	Severance Agreement between NRG Energy and John P. Brewster dated July 23, 2003.(2)
10.14	Registration Rights Agreement, dated December 5, 2003, among NRG Energy, Inc. and the holders of NRG Energy, Inc. common stock named therein.(3)
21	Subsidiaries of NRG Energy. Inc.(2)
23.1	Consent of PricewaterhouseCoopers LLP.(1)
31.1	Rule 13a-14(a)/15d-14(a) certification of David Crane.(1)
31.2	Rule 13a-14(a)/15d-14(a) certification of Robert Flexon.(1)
31.3	Rule 13a-14(a)/15d-14(a) certification of James Ingoldsby.(1)
32	Section 1350 Certification.(1)
99.1	Financial Statements of “West Coast Power.”(2)
99.2	Financial Statements of Louisiana Generating LLC for the year ended December 31, 2003.(3)
99.3	Financial Statements of NRG Northeast Generating LLC for the year ended December 31, 2003.(3)
99.4	Financial Statements of Indian River Power LLC for the year ended December 31, 2003.(3)
99.5	Financial Statements of NRG MidAtlantic Generating LLC for the year ended December 31, 2003.(3)
99.6	Financial Statements of NRG South Central Generating LLC for the year ended December 31, 2003.(3)

99.7	Financial Statements of NRG Eastern LLC for the year ended December 31, 2003.(3)
99.8	Financial Statements of Northeast Generation Holding LLC for the year ended December 31, 2003.(3)
99.9	Financial Statements of NRG International LLC for the year ended December 31, 2003.(3)

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* Exhibit relates to compensation arrangements.

(1) Filed herewith.

(2) Incorporated herein by reference to NRG Energy, Inc.'s annual report on Form 10-K filed on March 16, 2004.

(3) Incorporated herein by reference to NRG Energy Inc.'s Amendment No. 2 to its annual report on Form 10-K filed on November 3, 2004.

(4) Incorporated herein by reference to NRG Energy, Inc.'s annual report on Form 10-K filed on March 31, 2003.

(5) Incorporated herein by reference to NRG Energy's Registration Statement on Form S-1, as amended, Registration No. 333-33397.

(6) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q for the quarter ended June 30, 1999.

(7) Incorporated herein by reference to NRG Energy, Inc.'s current report on Form 8-K filed on November 19, 2003.

(8) Incorporated herein by reference to NRG Energy, Inc.'s quarterly report on Form 10-Q for the quarter ended June 30, 2004.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (No. 333-114007) and Form S-4 (No. 333-120205) of NRG Energy, Inc. of our reports dated March 10, 2004, except as to Notes 6, 20, 30 and 31 which are as of December 6, 2004, relating to the NRG Energy, Inc. consolidated financial statements and financial statement schedules, which appear in this Form 10-K Amendment No. 3.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota

December 7, 2004

Exhibit 31.1

CERTIFICATION

I, David Crane, certify that:

1. I have reviewed this annual report on Form 10-K/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 registrant's board of directors (or persons performing the equivalent function):

(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: December 7, 2004

Exhibit 31.2

CERTIFICATION

I, Robert Flexon, certify that:

1. I have reviewed this annual report on Form 10-K/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 registrant's board of directors (or persons performing the equivalent function):

(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: December 7, 2004

EXHIBIT 31.3

CERTIFICATION

I, James Ingoldsby, certify that:

1. I have reviewed this annual report on Form 10-K/ 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 registrant's board of directors (or persons performing the equivalent function):

(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: December 7, 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 Annual Report of NRG Energy, Inc. (the Company) on Form 10-K/A for the year ended December 31, 2003, as filed with the Securities and Exchange Commission on the date hereof (Form 10-K/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-K/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-K/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-K/A.

Date: December 7, 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.