NRG ENERGY, INC.
Form 8-K
December 20, 2005

Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549
FORM 8-K
CURRENT REPORT PURSUANT
TO SECTION 13 OR 15(D) OF THE
SECURITIES EXCHANGE ACT OF 1934
Date of report (Date of earliest event reported) September 30, 2005
NRG Energy, Inc.

(Exact Name of Registrant as Specified in Its Charter)
Delaware

(State or Other Jurisdiction of Incorporation)

001-15891	**41-1724239**
(Commission File Number)	(IRS Employer Identification No.)
211 Carnegie Center	**Princeton, NJ 08540**
(Address of Principal Executive Offices)	(Zip Code)

609-524-4500

(Registrant s Telephone Number, Including Area Code)

(Former Name or Former Address, if Changed Since Last Report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Table of Contents

Item 8.01. Other Events

This Current Report Form 8-K hereby amends the combined Annual Report on Form 10-K as separately filed by NRG Energy, Inc., or NRG, with the Securities and Exchange Commission on March 30, 2005, or the Original Filing, to reclassify the financial results of Northbrook New York LLC and Northbrook Energy LLC as discontinued operations   assets and liabilities on the consolidated balance sheet as of December 31, 2004, and as discontinued operations in the consolidated statement of operations and the consolidated statement of cash flows, for the year ended for the year ended December 31, 2004. The financial results of Northbrook New York LLC and Northbrook Energy LLC have not been reclassified as discontinued operations   assets and liabilities on the consolidated balance sheet as of December 31, 2003 and as discontinued operations in the consolidated statement of operations and the consolidated statement of cash flows, for the period December 6, 2003 through December 31, 2003 due to immateriality. Prior to December 6, 2003, Northbrook New York LLC and Northbrook New York LLC were unconsolidated affiliates because the ownership structure prevented us from exercising a controlling influence over operating and financial policies of the projects.

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

This Current Report Form 8-K amends and reclassifies Item 6, certain sections of Item 7 and Item 8 of the Original Filing, in each case, solely as a result of, and to reflect the reclassifications discussed above, and no other Items in the Original Filing are amended. In addition, pursuant to rules of the SEC, Item 15 of Part IV of the Original Filing has been amended to reflect the reclassifications discussed above and to contain the consents of NRG s independent registered public accounting firm. The consents of the Company s independent registered public accounting firm are included in this Current Report Form 8-K as Exhibits 99.4 and 99.5.

Index

Table of Contents

Item 6 ***Selected Financial Data***

The following table presents our selected financial data. The data included in the following table for the year ended December 31, 2004 has been restated to reflect the assets, liabilities and results of operations of Northbrook New York LLC and Northbrook Energy LLC, which have met the criteria for treatment as discontinued operations. No other periods presented have been restated. 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.

Table of Contents

	Reorganized NRG		Predecessor Company			
	Year Ended December 31, 2004	December 6 - December 31, 2003	January 1 - December 5, 2003	Year Ended December 31, 2002	2001	2000
	(In thousands, except per share amounts)					
Revenues from majority-owned operations	$2,347,882	$ 138,490	$ 1,798,387	$ 1,938,293	$ 2,085,350	$1,664,980
Corporate relocation charges	16,167					
Reorganization, restructuring and impairment charges	31,271	2,461	435,400	2,563,060		
Fresh start reporting adjustments			(4,118,636)			
Legal settlement			462,631			
Total operating costs and expenses	1,955,887	122,328	(1,475,523)	4,321,385	1,703,531	1,308,589
Write downs and losses on equity method investments	(16,270)		(147,124)	(200,472)		
Income/(loss) from continuing operations	159,144	11,405	2,949,078	(2,788,452)	210,502	149,729
Income/(loss) from discontinued operations, net	26,473	(380)	(182,633)	(675,830)	54,702	33,206
Net income/(loss)	185,617	11,025	2,766,445	(3,464,282)	265,204	182,935
Income/(loss) from continuing operations per weighted average share basic and diluted	$ 1.59	$ .11				
Total assets	7,830,283	9,244,987	N/A	10,896,851	12,915,222	5,986,289
Long-term debt, including current maturities	$3,723,854	$4,129,011	N/A	$ 7,782,648	$ 6,857,055	$3,194,340

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

	Reorganized NRG		Predecessor Company			
	Year Ended December 31, 2004	December 6 - December 31, 2003	January 1 - December 5, 2003	Year Ended December 31, 2002	2001	2000

			(In thousands)			
Energy and energy-related	$ 1,364,948	$ 78,018	$ 992,626	$ 1,183,514	$ 1,376,044	$ 1,091,115
Capacity	612,294	39,955	565,965	553,321	490,315	405,697
Alternative energy	175,715	12,064	115,911	97,712	161,845	92,671
O & M fees	20,852	1,135	12,942	14,413	15,789	10,073
Other	174,073	7,318	110,943	89,333	41,357	65,424
Total revenues from majority- owned operations	$ 2,347,882	$ 138,490	$ 1,798,387	$ 1,938,293	$ 2,085,350	$ 1,664,980

Energy and energy-related revenue consists of revenues received from third parties for sales in the day-ahead and real-time markets, as well as bilateral sales. In addition, this category includes day-ahead and real-time operating revenues.

Capacity revenue consists of revenues received from a third party at either the market or negotiated contract rates for making installed generation capacity available 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.

Table of Contents

Operations and management, or O&M, fees consist primarily 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. In addition, we also generate revenues from maintenance, the sale of ancillary services excluding day-ahead and real-time operating revenues 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. Also included in other revenues are revenues derived from financial transactions (derivatives) relating to the sale of energy or fuel which do not require the physical delivery of the underlying commodity.

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

Overview

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

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

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

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

Discontinued Operations. We have classified certain business operations, and gains/losses recognized on sale, as discontinued operations for projects that were sold or have met the required criteria for such classification pending final disposition. Accounting regulations require that continuing operations be reported separately in the income statement from discontinued operations, and that any gain or loss on the disposition of any such business be reported along with the operating results of such business. Assets classified as discontinued operations on our balance sheet as of December 31, 2004 consist of the McClain project. All other projects have been sold as of December 31, 2004.

Independent Registered Public Accounting Firm; Audit Committee. PricewaterhouseCoopers LLP served as our independent auditors from 1995 through 2003. On May 3, 2004, we announced that PricewaterhouseCoopers LLP had decided not to stand for re-election as our independent auditor for the year ended December 31, 2004. On May 24, 2004 the Audit Committee of our Board of Directors appointed KPMG LLP as our independent registered public accounting firm going forward, and on August 4, 2004 our stockholders ratified the appointment. PricewaterhouseCoopers LLP has consented to the inclusion of their reports for the periods January 1, 2003 to December 5, 2003 and December 6, 2003 to December 31, 2003 and for the year ended December 31, 2002. The

Company intends to continue to request the consent of PricewaterhouseCoopers LLP in future filings with the SEC when deemed necessary.

Table of Contents

Fresh Start Reporting. In connection with our emergence from bankruptcy, we adopted Fresh Start Reporting on December 5, 2003, in accordance with the requirements of Statement of Position 90-7, *Financial Reporting by Entities in Reorganization Under the Bankruptcy Code*, or SOP 90-7. The application of SOP 90-7 resulted in the creation of a new reporting entity. Under Fresh Start, our reorganization value was allocated to our assets and liabilities on a basis substantially consistent with purchase accounting in accordance with SFAS No. 141. Accordingly, our assets recorded values were adjusted to reflect their estimated fair values upon adoption of Fresh Start. Any portion of the reorganization value not attributable to specific assets is an indefinite-lived intangible asset referred to as reorganization value in excess of value of identifiable assets and reported as goodwill. We did not record any such amounts. As a result of adopting Fresh Start and emerging from bankruptcy, our historical financial information is not comparable to financial information for periods after our emergence from bankruptcy.

Results of Operations

Upon our emergence from bankruptcy, we adopted the Fresh Start provisions of SOP 90-7. Accordingly, the Reorganized NRG 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, therefore, the Predecessor Company s and the Reorganized NRG s amounts are discussed separately for comparison and analysis purposes, herein.

The following table shows the percent of total revenue each segment contributes to our total revenue:

Segments	Reorganized NRG For the Year Ended December 31, 2004 (In thousands)	Percent of Total Revenue	For the Period December 6-December 31, 2003 (In thousands)	Percent of Total Revenue	Predecessor Company For the Period January 1-December 5, 2003 (In thousands)	Percent of Total Revenue	For the Year Ended December 31, 2002 (In thousands)	Percent of Total Revenue
Wholesale Power Generation								
Northeast	$ 1,251,153	53.4%	$ 69,191	50.0%	$ 861,452	47.9%	$ 964,196	49.7%
South Central	418,145	17.8%	26,609	19.2%	356,534	19.8%	388,023	20.0%
West Coast	2,469	0.1%	(268)	(0.2)%	23,956	1.3%	30,796	1.6%
Other North America	92,102	3.9%	5,377	3.9%	85,388	4.8%	81,521	4.2%
Australia	181,065	7.7%	11,947	8.6%	151,494	8.4%	170,761	8.8%
All Other Other International	157,220	6.7%	13,082	9.4%	137,384	7.6%	108,379	5.6%
Alternative Energy	65,872	2.8%	3,852	2.8%	60,871	3.4%	69,030	3.6%
Non-Generation	186,425	7.9%	9,860	7.1%	129,063	7.2%	135,403	7.0%
Other	(6,569)	(0.3)%	(1,160)	(0.8)%	(7,755)	(0.4)%	(9,816)	(0.5)%
Total Revenue	$ 2,347,882	100.0%	$ 138,490	100.0%	$ 1,798,387	100.0%	$ 1,938,293	100.0%

The following table provides operating income by segment for the year ended December 31, 2004.

	Northeast	South Central	West Coast	Other North America (In thousands)	Australia	All Other	Total
Energy revenue	$ 853,454	$ 219,112	$ 9,276	$ 14,274	$ 159,381	$ 109,451	$ 1,364,948

Capacity revenue	264,624	183,483	(3,709)	84,097		83,799	612,294
Alternative revenue	49			1,748		173,918	175,715
O & M fees			(2)	186		20,668	20,852
Other revenue	133,026	15,550	(3,096)	(8,203)	21,684	15,112	174,073
Operating revenues	1,251,153	418,145	2,469	92,102	181,065	402,948	2,347,882
Operating expenses	859,769	294,215	10,842	52,523	161,960	321,104	1,700,413
Depreciation and amortization	72,665	62,458	800	20,583	24,027	27,503	208,036
Corporate relocation charges	11	1				16,155	16,167
Reorganization items	180	976		142		(14,688)	(13,390)
Restructuring and impairment charges	247	2,909		26,505		15,000	44,661
Operating income/(loss)	$ 318,281	$ 57,586	$ (9,173)	$ (7,651)	$ (4,922)	$ 37,874	$ 391,995

Table of Contents

For the Year Ended December 31, 2004 Compared to the Year Ended December 31, 2003

Net Income/(Loss)

Reorganized NRG

For the year ended December 31, 2004, we recorded net income of $185.6 million, or $1.85 per weighted average share of diluted common stock. These favorable results occurred despite a challenging market environment in 2004. Unseasonably mild weather, high volatility on forward markets and disappointing spot power prices summarize 2004 s events. The year started with colder than normal weather arriving in January but unseasonably mild weather characterized the period from March thru December which dampened energy prices in North America. The National Oceanic Atmospheric Agency, or NOAA, has ranked the mean average temperatures over the past 110 years by season for each of the lower 48 states. The year 2004 started with the winter being colder than normal in the east coast followed by a spring, summer and fall which were among the mildest in the last 110 years throughout most of the United States. Although mild weather in the North America market kept spot market on-peak power prices low throughout most of the year, relatively high gas and oil prices kept spark spreads on coal-based assets positive.

The overall perception that there would be significant production losses due to Hurricane Ivan ignited a strong pre-heating season rally in natural gas futures during the early fourth quarter. While power prices tracked changes in natural gas prices, this movement was not one for one. As a result, our spark spreads on coal-based generation increased dramatically with the fall 2004 changes in gas prices. During this period we sold forward 2005 power locking in these spark spreads. Forward power prices have fallen considerably from the highs set in October, and many of those forward sales, which were marked-to-market through earnings, significantly contributed to the $57.3 million unrealized gain recorded in revenue for the year ended December 31, 2004 and as more fully described in Note 16 to the financial statements.

As indicated above, our 2004 results were favorably impacted by the cold weather in January. Additionally, the Northeast s income results for the year were positively impacted by the $57.3 million of unrealized gains associated with forward sale transactions supporting our Northeast assets. The majority of the unrealized gains relate to forward sales of electricity which will be realized in 2005. These gains were offset by our South Central region s results, which were negatively impacted by an unplanned outage in the fourth quarter forcing us to purchase power to meet our contract supply obligations. Impairment charges of $44.7 million negatively impacted net income; of which $26.5 million relates to the Kendall asset. Our results were also favorably impacted by the FERC-approved settlement agreement between NRG Energy and Connecticut Light & Power, or CL&P, and others concerning the congestion and losses obligation associated with a prior standard offer service contract, whereby we received $38.4 million in settlement proceeds in July 2004. The 2004 results were also positively impacted by $159.8 million in equity earnings of unconsolidated affiliates including $68.9 million from our interest in West Coast Power which benefited from warmer than normal temperatures during the year.

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 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.

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 pre-petition 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 also revalued our assets and liabilities to fair value. Accordingly, we substantially wrote down the value of our fixed assets. We recorded a net $1.6 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 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 costs 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 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.

Revenues from Majority-Owned Operations

Reorganized NRG

Our revenues from majority-owned operations were $2.3 billion for the year ended December 31, 2004 which included $1.4 billion of energy revenues, $612.3 million of capacity revenues, $175.7 million of alternative energy revenues, $20.9 million of O&M fees and $174.1 million of other revenues, which include $57.3 million of unrealized gains associated with financial sales transactions of electricity, which are marked to market, $22.4 million from ancillary service revenues and the remainder related to financial and physical gas sales and non-cash contract amortization resulting from fresh start accounting and other miscellaneous revenue items.

Revenues from majority-owned operations for the year ended December 31, 2004, were driven primarily by our North American operations, primarily our Northeast facilities. Our wholly-owned domestic Northeast power generation operations significantly contributed to our energy revenues. Our wholly-owned North America assets generated approximately 29.0 million megawatt hours during the year 2004 with the Northeast region representing 45.6% of these megawatt hours. Of the total $1.4 billion in energy revenues, the Northeast region represented 63%. Our energy revenues were favorably impacted by the FERC-approved settlement agreement between us and CL&P and others, whereby we received $38.4 million in settlement proceeds in July 2004. These settlement proceeds are included in the All Other segment in the energy revenue category. South Central s energy revenues are driven by our ability to sell merchant energy, which is dependent upon available generation from our coal-based Louisiana Generating company after serving our co-op customer and long-term customer load obligations. Since our load obligation is primarily residential load, our merchant opportunities are largely available in the off-peak hours of the day. Our Australian operations were favorably impacted by strong market prices driven by gas restrictions in January, record high temperatures in February and March, and favorable foreign exchange movements. Our capacity revenues are largely driven by our Northeast and South Central facilities. Our South Central and New York City assets earned 30% and 26% of our total capacity revenues, respectively. In the Northeast, our Connecticut facilities continue to benefit from the cost-based reliability must-run, or RMR agreements, which were authorized by FERC as of January 17, 2004 and approved by FERC on January 27, 2005. The agreements entitle us to approximately $7.1 million of capacity revenues per month until January 1, 2006, the LICAP implementation date. In the South Central region, our long-term contracts provide for capacity payments. Other North American capacity revenues were generated by our Kendall operation, which had a long-term tolling agreement. During this period we also experienced a favorable impact on our revenues due to the mark-to-market on certain of our derivative contracts wherein we have recognized $57.3 million in unrealized gains. This gain is related to our Northeast assets and is included in Other Revenue. Also included in Other Revenue in the Northeast are the cost reimbursement funds under the RMR agreement for our Connecticut assets. Our revenues during this period include net charges of $35.3 million of non-cash amortization of the fair values of various executory contracts recorded on our balance sheet upon our adoption of the Fresh Start provisions of SOP 90-7 in December 2003.

Our revenues from majority-owned operations were $138.5 million for the period December 6, 2003 through December 31, 2003.

Table of Contents

Predecessor Company

Revenues from majority-owned operations were $1.8 billion for the period January 1, 2003 through December 5, 2003 and include $992.6 million of energy revenues, $566.0 million of capacity revenues, $115.9 million of alternative energy, $12.9 million of O&M fees and $110.9 million of other revenues which include financial and physical gas sales, sales from our Schkopau facility and NEPOOL expense reimbursements. Revenues from majority-owned operations during the period ended December 5, 2003, were driven primarily by our North American operations and to a lesser degree by our international operations, primarily Australia. Our domestic Northeast and South Central power generation operations significantly contributed to our revenues due primarily to favorable market prices resulting from strong fuel and electricity prices. Our Australian operations were favorably impacted by foreign exchange rates. During this period we also experienced an unfavorable impact on our revenues due to continued losses on our CL&P standard offer contract and the mark-to-market on certain of our derivatives.

Cost of Majority-Owned Operations

Reorganized NRG

Our cost of majority-owned operations for the year ended December 31, 2004 was $1.5 billion or 63.5% of revenues from majority-owned operations. Cost of majority-owned operations consist of $1.008 billion of cost of energy (primarily fuel and purchased energy costs), or 42.9% of revenues from majority-owned operations and $482.1 million of operating expenses, or 20.5% of revenues from majority-owned operations. Operating expenses consist of $207.1 million of labor related costs, $235.1 million of operating and maintenance costs, $37.3 million of non-income based taxes and $2.9 million of asset retirement obligation accretion.

Cost of Energy

Fuel related costs include $478.3 million in coal costs, $233.0 million in natural gas costs, $104.7 million in fuel oil costs, $38.8 million in transmission and transportation expenses, $100.4 million of purchased energy costs, $34.8 million in other costs and $17.8 million in non-cash SO(2) emission credit amortization resulting from Fresh Start accounting. The Northeast region consumed 50%, 64% and 92% of total coal, natural gas and oil expenditures, respectively. The South Central region, which is comprised mainly of our Louisiana base-loaded coal plant, consumed 32% of our total coal expenditures.

Operating Expenses

Operating expenses related to continuing operations for the year ended December 31, 2004 were $482.1 million or 20.5% of revenues from majority-owned operations. Operating expenses include labor, normal and major maintenance costs, environmental and safety costs, utilities costs, and non-income based taxes. Labor costs include regular, overtime and contract costs at our plants and totaled $207.1 million. The Northeast region, where the majority of our assets reside, represents 53% of total labor costs; Australia represents 18%, while our South Central region represents 11%. Of the total O&M costs, normal and major maintenance at our plants accounted for $176.3 million, or 36.6% of total operating costs. Maintenance costs were largely driven by planned outages across our fleet, and the low-sulfur coal conversion in western New York. The Northeast region represented over half of the normal and major maintenance, with a total of $98.6 million in costs in 2004 while Australia had $38.8 million in normal and major maintenance, or 22%. Operating expenses were positively impacted by a $7 million favorable settlement with a vendor regarding auxiliary power charges. Non-income based taxes totaled $37.3 million net of $34.6 million in property tax credits, primarily associated with an enterprise zone program.

Cost of majority-owned operations was $95.5 million, or 69.0% of revenues from majority-owned operations for the period December 6, 2003 through December 31, 2003. Cost of energy for this period was $62.3 million or 45.0% of revenues from majority-owned operations and operating expenses were $33.2 million, or 24.0% of revenues from majority-owned operations. Labor during this period totaled $11.1 million. Normal and major maintenance was $12 million with 70% of the total normal and major maintenance for this time period coming from our Northeast region.

Predecessor Company

Cost of majority-owned operations was $1.4 billion, or 75.4% of revenues from majority-owned operations for the period January 1, 2003 through December 5, 2003. Cost of majority-owned operations was unfavorably impacted by increased generation in the Northeast region, partially offset by a reduction in trading and hedging activity resulting from a reduction in our power marketing

Table of Contents

activities. Our international operations were impacted by an unfavorable movement in foreign exchange rates and continued mark-to-market of the Osborne contract at Flinders resulting from lower pool prices.

Depreciation and Amortization

Reorganized NRG

Our depreciation and amortization expense related to continuing operations for the year ended December 31, 2004 was $208.0 million. Depreciation and amortization consists primarily of the allocation of our historical depreciable fixed asset costs over the remaining lives of such property. Upon adoption of Fresh Start, we were required to revalue our fixed assets to fair value and determine new remaining lives for such assets. Our fixed assets were written down substantially upon our emergence from bankruptcy. We also determined new remaining depreciable lives, which are, on average, shorter than what we had previously used primarily due to the age and condition of our fixed assets.

Depreciation and amortization expense for the period December 6, 2003 through December 31, 2003 was $11.8 million. Depreciation and amortization expense consists of the allocation of our newly valued basis in our fixed assets over newly determined remaining fixed asset lives.

Predecessor Company

Our depreciation and amortization expense related to continuing operations for the period January 1, 2003 through December 5, 2003 was $218.8 million. During this period, depreciation expense was unfavorably impacted by the shortening of the depreciable lives of certain of our domestic power generation facilities located in the Northeast region and the impact of recently completed construction projects. The depreciable lives of certain of our Northeast facilities, primarily our Connecticut facilities, were shortened to reflect economic developments in that region. Certain capitalized development costs were written-off in connection with the Loy Yang project resulting in increased expense. Amortization expense increased due to reducing the life of certain software costs.

General, Administrative and Development

Reorganized NRG

Our general, administrative and development costs related to continuing operations for the year ended December 31, 2004 were $210.2 million. Of this total, $110.0 million or 4.7% of revenues from majority-owned operations represents our corporate costs, with the remaining $100.1 million representing costs at our plant operations. Corporate costs are primarily comprised of corporate labor, external professional support, such as legal, accounting and audit fees, and office expenses. Corporate general, administrative and development expenses were negatively impacted this year by increased legal fees, increased audit costs and increased consulting costs due to our Sarbanes Oxley testing and implementation. Plant general, administrative and development costs primarily include insurance and external consulting costs. Plant insurance costs were $40.0 million. Additionally, we recorded $11.7 million in bad debt expense related to notes receivable.

General, administrative and development costs were $12.5 million, or 9.0% of revenues from continuing operations for the period December 6, 2003 to December 31, 2003. These costs are primarily comprised of corporate labor, insurance and external professional support, such as legal, accounting and audit fees.

Predecessor Company

Our general, administrative and development costs related to continuing operations for the period January 1, 2003 to December 5, 2003 were $170.3 million or 9.5% of revenues from majority-owned operations. These costs are primarily comprised of corporate labor, insurance and external professional support, such as legal, accounting and audit fees.

Other Charges (Credits)

Reorganized NRG

For the year ended December 31, 2004, we recorded other charges of $47.4 million, which consisted of $16.2 million of corporate relocation charges, $13.4 million of reorganization credits and $44.6 million of restructuring and impairment charges.

Table of Contents

For the period December 6, 2003 through December 31, 2003 we recorded $2.5 million of reorganization charges.

Predecessor Company

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, $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.

Other charges (credits) consist of the following:

	Reorganized NRG		Predecessor Company
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003
		(In thousands)	
Corporate relocation charges	$ 16,167	$	$
Reorganization items	(13,390)	2,461	197,825
Impairment charges	44,661		228,896
Restructuring charges			8,679
Fresh Start adjustments			(4,118,636)
Legal settlement			462,631
Total	$ 47,438	$ 2,461	$ (3,220,605)

Corporate Relocation Charges

On March 16, 2004, we announced plans to implement a new regional business strategy and structure. The new structure called for a reorganized leadership team and a corporate headquarters relocation to Princeton, New Jersey. The corporate headquarters staff were streamlined as part of the relocation, as functions were either reduced or shifted to the regions. The transition of the corporate headquarters is substantially complete. During the year ended December 31, 2004, we recorded $16.2 million for charges related to our corporate relocation activities, primarily for employee severance and termination benefits and employee related transition costs. These charges are classified separately in our statement of operations, in accordance with SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. We expect to incur an additional $7.7 million of SFAS No. 146-classified expenses in connection with corporate relocation charges for a total of $23.9 million. Of this total, relocating, recruiting and other employee-related transition costs are expected to be approximately $11.9 million and have been and will continue to be expensed as incurred. These costs and cash payments are expected to be incurred through the second quarter of 2005. Severance and termination benefits of $7.2 million are expected to be incurred through the second quarter of 2005 with cash payments being made through the fourth quarter of 2005. Building lease termination costs are expected to be $4.8 million. These costs are expected to be incurred through the first quarter of 2005 with cash payments being made through the fourth quarter of 2006. Costs not classified separately as relocation charges include rent expense of our temporary office in Princeton, construction costs of our new office and certain labor costs. All costs relating to the corporate relocation that are not classified separately as relocation charges, except for approximately $5.7 million of related capital expenditures will be expensed as incurred and included in general, administrative and development expenses. Cash expenditures for 2004, including capital expenditures, were $22.4 million. We currently estimate total costs associated with the corporate relocation to be approximately $40.0 million.

We recognized a curtailment gain of $750,000 on our defined benefit pension plan in the fourth quarter of 2004, as a substantial number of our current headquarters staff left the Company in this period.

Reorganization Items

For the year ended December 31, 2004, we recorded a net credit of $13.4 million related primarily to the settlement of obligations recorded under Fresh Start. We incurred $7.4 million of professional fees associated with the bankruptcy which offset $20.8 million of credits associated with creditor settlements. For the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, we incurred $2.5 million and $197.8 million, respectively, 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.

Table of Contents

	Reorganized NRG		Predecessor Company
	Year Ended December 31, 2004	For the period December 6 - December 31, 2003	For the period January 1 - December 5, 2003
	(In thousands)		
Reorganization items			
Professional fees	$ 7,383	$ 2,461	$ 82,186
Deferred financing costs			55,374
Pre-payment settlement			19,609
Interest earned on accumulated cash			(1,059)
Contingent equity obligation			41,715
Settlement of obligations	(20,773)		
Total reorganization items	$ (13,390)	$ 2,461	$ 197,825

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 $44.7 million and $228.9 million for the year ended December 31, 2004 and the period January 1, 2003 through December 5, 2003, respectively, as shown in the table below. Of the $44.7 million total in 2004, Kendall and the Meriden turbine accounted for $26.5 million and $15.0 million, respectively. Both of these charges were based on indicative market valuations. We successfully completed the sale of Kendall in November 2004 and expect to complete the sale of the Meriden turbine in the first quarter of 2005. There were no impairment charges for the period December 6, 2003 through December 31, 2003.

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.

Impairment charges (credits) included the following asset impairments (realized gains) for the year ended December 31, 2004 and the period January 1, 2003 to December 5, 2003.

	Reorganized	Predecessor Company

Project Name	Project Status	NRG Year Ended December 31, 2004	For the Period January 1 - December 5, 2003	Basis of Impairment Charge
		(In thousands)		
Louisiana Generating LLC	Office building and land being marketed	$ 493	$	Estimated market price
New Roads Holding LLC (turbine)	Non-operating asset abandoned	2,416		Projected cash flows
Devon Power LLC	Operating at a loss in 2003	247	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		(3,091)	Estimated market price

Table of Contents

Project Name	Project Status	Reorganized NRG Year Ended December 31, 2004	Predecessor Company For the Period January 1 - December 5, 2003	Basis of Impairment Charge
			(In thousands)	
Turbines	Sold		(21,910)	Realized gain
Berrians Project	Terminated		14,310	Realized loss
TermoRio	Terminated		6,400	Realized loss
Meriden	Sold	15,000		Similar asset prices
Kendall and other expansion projects	Sold	26,505		Projected cash flows, sales contracts
Other			2,617	
Total impairment charges		$ 44,661	$ 228,896	

Restructuring Charges

We incurred $8.7 million of employee separation costs and advisor fees during the period January 1, 2003 until we filed for bankruptcy in May 2003. Subsequent to that date we recorded all advisor fees as reorganization costs.

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. 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

Legal Settlement Charges

During the period January 1, 2003 to December 5, 2003, we recorded $462.6 million of legal settlement charges which consisted of the following. We recorded $396.0 million in connection with the resolution of an arbitration claim asserted by FirstEnergy Corp. 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 NRG Energy s Plan of Reorganization. In November 2003, we settled litigation with Fortistar Capital in which Fortistar Capital released us from all litigation claims in exchange for a $60.0 million pre-petition bankruptcy claim and an $8.0 million post-petition bankruptcy 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 November 2003, we settled our dispute with Dick Corporation in connection with Meriden Gas Turbines LLC through the payment of a general unsecured claim and a post-petition pre-confirmation payment. This settlement resulted in our recording an additional liability of $8.0 million in November 2003.

In August 1995, we entered into a Marketing, Development and Joint Proposing Agreement, or the Marketing Agreement, with Cambrian Energy Development LLC, or Cambrian. Various claims arose in connection with the 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 paid 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.

Table of Contents

Other Income (Expense)

Reorganized NRG

During the year ended December 31, 2004, we recorded other expense of $167.5 million. Other expense consisted primarily of $266.1 million of interest expense, $71.6 million of refinancing-related expenses, and $16.3 million of write downs and losses on sales of equity method investments, offset by $159.8 million of equity in earnings of unconsolidated affiliates (including $68.9 million from our investment in West Coast Power LLC) and $26.7 million of other income, net.

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 in earnings of unconsolidated affiliates.

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, net.

Minority Interest in Earnings of Consolidated Subsidiaries

For the year ended December 31, 2004, minority interest in earnings of consolidated subsidiaries was $16,000. 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.

Equity in Earnings of Unconsolidated Affiliates

Reorganized NRG

For the year ended December 31, 2004, we recorded $159.8 million of equity earnings from our investments in unconsolidated affiliates. Our equity in earnings of West Coast Power comprised $68.9 million of this amount with our equity in earnings of Enfield, Mibrag, and Gladstone comprising $28.5 million, $20.9 million, and $17.5 million, respectively. Our investment in West Coast Power generated favorable results due to the pricing under the California Department of Water Resources contract. Additionally, revenues from ancillary services revenue and minimum load cost compensation power positively contributed to West Coast Power s operating results. However, our equity earnings in the project as reported in our results of operations have been reduced by a net $115.8 million to reflect a non-cash basis adjustment for in the money contracts resulting from adoption of Fresh Start.

NRG Energy s equity earnings were also favorably impacted by $23.3 million of unrealized gain related to our Enfield investment. This gain is associated with changes in the fair value of energy-related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

Equity in earnings of unconsolidated affiliates of $13.5 million for the period December 6, 2003 through December 31, 2003 consists primarily of equity earnings from our 50% ownership in West Coast Power of $9.4 million.

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.

Table of Contents

Equity in earnings of unconsolidated affiliates consists of the following:

	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	December 6, 2003 Through December 31, 2003	January 1, 2003 Through December 5, 2003	Year Ended December 31, 2002
	(In thousands)			
West Coast Power	$ 68,895	$ 9,362	$ 98,741	$ 19,044
MIBRAG	20,938	102	21,818	28,750
Enfield	28,505	481	5,975	(6,017)
Gladstone	17,528	997	12,440	7,237
Rocky Road	6,904	305	6,864	6,868
James River	7,750	543	(1,893)	9,713
NRG Saguaro	5,480	617	3,940	4,968
Scudder LA Trust	1,521	150	2,653	1,043
NRG National	846	190	2,010	1,695
MWPC RDF	200	8	123	259
NRG Cadillac	(421)	(2)	280	195
Central and Eastern European Energy Power Fund	(47)	(22)	(260)	(331)
Loy Yang			17,924	8,443
Other	1,726	790	286	(12,871)
Total Equity in Earnings of Unconsolidated Affiliates	$ 159,825	$ 13,521	$ 170,901	$ 68,996

Write Downs and Losses on Sales of Equity Method Investments

As part of our periodic review of our equity method investments for impairments, we have taken write downs and losses on sales of equity method investments during the year ended December 31, 2004 of $16.3 million and $147.1 million for the period January 1, 2003 through December 5, 2003. Our Commonwealth Atlantic Limited Partnership (CALP) and James River investments were written down based on indicative market bids. The sale of CALP closed in the fourth quarter of 2004, while the sale agreement for James River has been terminated. There were no write downs and losses on sales of equity method investments for the period December 6, 2003 through December 31, 2003.

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

	Reorganized NRG	Predecessor Company For the Period
	Year Ended December 31, 2004	January 1 - December 5, 2003

	(In thousands)	
Commonwealth Atlantic Limited Partnership	$ 4,614	$
James River Power LLC	7,293	
NEO Corporation	3,830	
Calpine Cogeneration	(735)	
NLGI Minnesota Methane		12,257
NLGI MM Biogas		2,613
Kondapalli		(519)
ECKG		(2,871)
Loy Yang	1,268	146,354
Mustang		(12,124)
Other		1,414
Total write downs and losses of equity method investments	$ 16,270	$ 147,124

Commonwealth Atlantic Limited Partnership (CALP) In June 2004, we executed an agreement to sell our 50% interest in CALP. During the third quarter of 2004, we recorded an impairment charge of approximately $3.7 million to write down the value of our investment in CALP to its fair value. The sale closed in November 2004, resulting in net cash proceeds of $14.9 million. Total impairment charges as a result of the sale were $4.6 million.

James River Power LLC In September 2004, we executed an agreement with Colonial Power Company LLC to sell all of our outstanding shares of stock in Capistrano Cogeneration Company, a wholly-owned subsidiary of NRG Energy which owns a 50% interest in James River Cogeneration Company. During the third quarter of 2004, we recorded an impairment charge of approximately $6.0 million to write down the value of our investment in James River to its fair value. During the fourth quarter of 2004, the sale agreement was terminated. We continue to impair any additional equity earnings based on its fair value. Total impairment charges for 2004 were $7.3 million.

NEO Corporation On September 30, 2004, we completed 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. The sale also included four wholly-owned NEO subsidiaries (see Item 15 Note 6). We received cash proceeds of $6.1 million. The sale resulted in a loss of approximately $3.8 million attributable to the equity investment entities sold.

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

NLGI 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, resulting in a net impairment charge of $12.3 million for the period January 1, 2003 to December 5, 2003. This gain resulted from the release of certain obligations.

NLGI 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 a 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, resulting in a net gain of $0.5 million. The gain resulted from incurring lower selling costs than estimated as part of the first quarter impairment.

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

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. This write-down reflected management s belief that the decline in fair value of the investment was other than temporary. 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. Consequently, we recorded an additional impairment charge of approximately $146.4 million during 2003. In April 2004, we completed the sale of Loy Yang which resulted in net cash proceeds of $26.7 million and a loss of $1.3 million.

Mustang Station On July 7, 2003, we completed the sale of our 25% 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.

Other Income, net

Reorganized NRG

During the year ended December 31, 2004, we recorded $26.7 million of other income, net, consisting primarily of interest income earned on notes receivable and cash balances. For the period December 6, 2003 through December 31, 2003 we recorded other income of $97,000.

Predecessor Company

During the period January 1, 2003 through December 5, 2003, we recorded $19.2 million of other income, net. During this period other income, net consisted primarily of interest income earned on notes receivable and cash balances, offset in part by the unfavorable mark-to-market on our corporate level £160 million note that was cancelled in connection with our bankruptcy proceedings.

Interest Expense

Reorganized NRG

Interest expense for the year ended December 31, 2004 was $266.1 million, consisting of interest expense on both our project- and corporate-level interest-bearing debt. Significant amounts of our corporate-level debt were forgiven upon our emergence from bankruptcy and we refinanced significant amounts of our project-level debt with corporate level high yield notes and term loans in December 2003. Also included in interest expense is the amortization of debt financing costs of $9.2 million related to our corporate level debt and $13.3 million of amortization expense related primarily to debt discounts and premiums recorded as part of Fresh Start. Interest expense also includes the impact of any interest rate swaps that we have entered in order to manage our exposure to changes in interest rates.

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 Second Priority 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.

Predecessor Company

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. Interest expense during this period was favorably impacted by our ceasing to record interest expense on debt where it was probable that such interest would not be paid, such as the NRG Energy corporate level debt (primarily bonds) and the NRG Finance Company debt (construction revolver) due to our entering into bankruptcy in May 2003. 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. Interest expense was unfavorably impacted by an adverse mark-to-market on certain interest rate swaps that we have entered in order to manage our exposure to changes in interest rates. Due to our deteriorating financial condition during such period, hedge accounting treatment was ceased for certain of our interest rate swaps, causing changes in fair value to be recorded as interest expense.

Refinancing Expense

Refinancing expense was $71.6 million for the year ended December 31, 2004. This amount includes $15.1 million of prepayment penalties and a $15.3 million write-off of deferred financing costs related to refinancing certain amounts of our term loans with additional corporate level high yield notes in January 2004 and $13.8 million of prepayment penalties and a $26.8 million write-off of deferred financing costs related to refinancing the senior credit facility in December 2004.

Income Tax Expense

Reorganized NRG

Our income tax provision from continuing operations was $65.4 million for the year ended December 31, 2004 and an income tax benefit of ($0.7) million for the period December 6, 2003 through December 31, 2003. The overall effective tax rate in 2004 and the short period in 2003 was 29.1% and (6.2%), respectively. The change in our effective tax rate was primarily due to a state tax refund received from Xcel Energy in 2003 and foreign income taxed in jurisdictions with tax rates different from the U.S. statutory rate.

Our net deferred tax assets at December 31, 2004 were offset by a full valuation allowance in accordance with SFAS No. 109. Under SOP 90-7, any future benefits from reducing a valuation allowance from preconfirmation deferred tax assets are required to be reported first as an adjustment of identifiable intangible assets and then as a direct addition to paid in capital versus a benefit on our statement of operations.

The effective tax rate may vary from year to year depending on, among other factors, the geographic and business mix of earnings and losses. These same and other factors, including history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Predecessor Company

Income tax expense for the period January 1, 2003 through December 5, 2003 was $37.9 million. The overall effective tax rate for the period ended December 5, 2003 was 1.3%. The rate is lower than the U.S. statutory rate primarily due to a release in valuation allowance for net operating loss carryforwards that were utilized following our emergence from bankruptcy to offset the current tax on cancellation of debt income.

Income taxes have been recorded on the basis that our U.S. subsidiaries and we would file separate federal income tax returns for the period January 1, 2003 through December 5, 2003. Since our U.S. subsidiaries and we were not 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 filed 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.

Income From Discontinued Operations, net of Income Taxes

Reorganized NRG

We classified as discontinued operations the operations and gains/losses recognized on the sale of projects that were sold or were deemed to have met the required criteria for such classification pending final disposition. During the year ended December 31, 2004, we recorded income from discontinued operations, net of income taxes, of $26.5 million. During the year ended December 31, 2004, discontinued operations consisted of the results of our NRG McClain LLC, Penobscot Energy Recovery Company, or PERC, Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee, Hsin Yu, LSP Energy (Batesville), Northbrook Energy LLC, Northbrook New York LLC, and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC). For the period December 6, 2003 to December 31, 2003, discontinued operations consisted of the results of our NRG McClain LLC, Penobscot Energy Recovery Company, or PERC, Compania Boliviana De Energia Electrica S.A. Bolivian Power Company Limited, or Cobee, Hsin Yu, LSP Energy (Batesville), and four NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC). The results of Northbrook New York LLC and Northbrook Energy LLC were not included in the period December 6, 2003 to December 31, 2003 due to immateriality. All other discontinued operations were disposed of in prior periods. The $26.5 million income from discontinued operations includes a gain of $22.4 million, net of income taxes of $7.9 million, related primarily to the dispositions of Batesville, Cobee and Hsin Yu.

19

Discontinued operations for the period December 6, 2003 through December 31, 2003 is comprised of a loss of $0.4 million attributable to the ongoing 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).

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, NEO Landfill Gas, Inc., or NLGI, seven NEO Corporation projects (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC, NEO Tajiguas LLC, NEO Ft. Smith LLC, NEO Woodville LLC and NEO Phoenix LLC), Timber Energy Resources, Inc., or 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 of $100.7 million and $23.6 million, respectively, recorded at McClain and NLGI and fresh start adjustments at LSP Energy.

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

Net Income

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.

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 pre-petition 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 $1.6 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 costs 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 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.

Table of Contents

Revenues from Majority-Owned Operations

Reorganized NRG

Our operating revenues from majority-owned operations were $138.5 million for the period December 6, 2003 through December 31, 2003.

Predecessor Company

Revenues from majority-owned operations were $1.8 billion for the period January 1, 2003 through December 5, 2003 and include $992.6 million of energy revenues, $566.0 million of capacity revenues, $115.9 million of alternative energy, $12.9 million of O&M fees and $110.9 million of other revenues which include financial and physical gas sales, sales from our Schkopau facility and NEPOOL expense reimbursements. Revenues from majority-owned operations during the period year ended December 5, 2003, were driven primarily by our North American operations and to a lesser degree by our international operations, primarily Australia. Our domestic Northeast and South Central power generation operations significantly contributed to our revenues due primarily to favorable market prices resulting from strong fuel and electricity prices. Our Australian operations were favorably impacted by favorable foreign exchange rates. During this period we also experienced an unfavorable impact on our revenues due to continued losses on our CL&P standard offer contract and the mark-to-market on certain of our derivatives.

Revenues from majority-owned operations were $1.9 billion for the year ended December 31, 2002.

Cost of Majority-Owned Operations

Reorganized NRG

Our cost of majority-owned operations for the period December 6, 2003 through December 31, 2003 was $95.5 million or 69.0% of revenues from majority-owned operations.

Predecessor Company

Cost of majority-owned operations was $1.4 billion, or 75.4% of revenues from majority-owned operations for the period January 1, 2003 through December 5, 2003. Cost of majority-owned operations was unfavorably impacted by increased generation in the Northeast region, partially offset by a reduction in trading and hedging activity resulting from a reduction in our power marketing activities. Our international operations were unfavorably impacted due to an unfavorable movement in foreign exchange rates and continued mark-to-market of the Osborne contract at Flinders resulting from lower pool prices.

Our cost of majority-owned operations related to continuing operations was $1.3 billion for 2002, or 68.7% of revenues from majority-owned operations. 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. Cost of energy for the year ended December 31, 2002 was $900.9 million or 46.5% of revenue from majority-owned operations.

Depreciation and Amortization

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 expense 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.

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. During the period January 1, 2003 to December

5, 2003, depreciation expense was unfavorably impacted by the shortening of the depreciable lives of certain of our domestic power generation facilities located in the Northeast region and the impact of completed construction projects. 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.

General, Administrative and Development

Reorganized NRG

Our general, administrative and development costs for the period December 6, 2003 through December 31, 2003 was $12.5 million or 9.0% of revenues from majority-owned operations. These costs are primarily comprised of corporate labor, insurance and external professional support, such as legal, accounting and audit fees.

Predecessor Company

Our general, administrative and development costs for the period January 1, 2003 through December 5, 2003 were $170.3 million, or 9.5% of revenues from majority-owned operations. Our general, administrative and development costs for 2002 were $218.9 million, or 11.3% of revenues from majority-owned operations. General, administrative and development costs for the period January 1, 2003 through December 5, 2003 were favorably impacted by 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)

Reorganized NRG

During the period December 6, 2003 through December 31, 2003 we recorded $2.5 million of other charges related to reorganization items.

Predecessor Company

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, $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 period January 1, 2003 to December 5, 2003 and the year ended December 31, 2002. There were no impairment charges for the period December 6, 2003 through December 31, 2003.

Table of Contents

Project Name	Project Status	Predecessor Company For the Period January 1 - December 5, 2003 (In thousands)	Predecessor Company Year Ended December 31, 2002 (In thousands)	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	(3,091)	42,333	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		2,617	28,851	
Total impairment charges (credits)		$ 228,896	$ 2,451,745	

Reorganization Items

For the period from December 6, 2003 to December 31, 2003 we incurred $2.5 million in reorganization costs. For the period from January 1, 2003 to December 5, 2003, we incurred $197.8 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):

	Reorganized NRG For the Period December 6 - December 31, 2003	Predecessor Company For the Period January 1 - December 5, 2003
	(In thousands)	
Reorganization items		
Professional fees	$ 2,461	$ 82,186
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	$ 2,461	$ 197,825

Restructuring Charges

We incurred $8.7 million of employee separation costs and advisor fees during the period January 1, 2003 until we filed for bankruptcy in May 2003. Subsequent to that date we recorded all advisor fees as reorganization costs. 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.

23

Legal Settlement Charges

During the period January 1, 2003 to December 5, 2003, we recorded $462.6 million of legal settlement charges which consisted of the following. We recorded $396.0 million in connection with the resolution of an arbitration claim asserted by FirstEnergy Corp. 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 NRG Energy s plan of reorganization. In November 2003, we settled litigation with Fortistar Capital in which Fortistar Capital released us from all litigation claims in exchange for a $60.0 million pre-petition bankruptcy claim and an $8.0 million post-petition bankruptcy 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 November 2003, we settled our dispute with Dick Corporation in connection with Meriden Gas Turbines LLC through the payment of a general unsecured claim and a post-petition pre-confirmation payment. This settlement resulted in our recording an additional liability of $8.0 million in November 2003.

In August 1995, we entered into a Marketing, Development and Joint Proposing Agreement, or the Marketing Agreement, with Cambrian Energy Development LLC, or Cambrian. Various claims arose in connection with the 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 paid 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.

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. 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)

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 in earnings of unconsolidated affiliates.

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.

Table of Contents

For the year ended December 31, 2002, other expenses were $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, partially offset by equity in earnings of unconsolidated affiliates of $69.0 million and other income, net of $11.5 million.

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.

Reorganized NRG

Equity in earnings of unconsolidated affiliates of $13.5 million for the period December 6, 2003 through December 31, 2003 consists primarily of equity earnings from our 50% ownership in West Coast Power of $9.4 million.

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.

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. During the period January 1, 2003 to December 5, 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 primarily of the write down of our investment in the Loy Yang project of $146.4 million, our investment in the NEO Corporation Minnesota Methane project of $12.3 million and our investment in NEO Corporation MM Biogas of $2.6 million. These losses were partially offset by gains on the sale of our investment in the ECKG and Mustang projects of $2.9 million and $12.1 million, respectively. 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 primarily 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 $3.2 million, respectively among others, offset by a $9.9 million gain on sale of our Kingston project.

Other income, net

Other income, net consists primarily of interest income earned on notes receivable and cash balances. We recorded $97,000, $19.2 million and $11.4 million of other income, net for the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003 and for the year ended December 31, 2002, respectively.

Interest expense

Reorganized NRG

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 Second Priority 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.

Table of Contents

Predecessor Company

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 pre-petition 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.

Interest expense was $452.2 million for the year ended December 31, 2002.

Income Tax

Reorganized NRG

Income tax benefit for the period December 6, 2003 through December 31, 2003 was ($0.7) million and the overall effective tax rate was (6.2%). The rate is lower than the U.S. statutory rate primarily due to a state tax refund received from Xcel Energy in 2003, foreign income taxed in jurisdictions with tax rates different from the U.S. statutory rate and a decrease in unfavorable permanent differences.

Our deferred tax assets at December 31, 2003 were offset by a full valuation allowance in accordance with SFAS No. 109. Under SOP 90-7, any future benefits from reducing a valuation allowance from preconfirmation deferred tax assets are required to 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 the realization of our deferred tax assets, which were fully valued as of the date of our emergence from bankruptcy. The adoption of this Statement of Position will result in a disallowance of a future income statement benefit of $1.3 billion as a result of a reduction to the intangible asset for realization of benefits of fully valued deferred tax assets as of December 5, 2003 (date of emergence from bankruptcy).

The effective tax rate may vary from year to year depending on, among other factors, the geographic and business mix of earnings and losses. These same and other factors, including history of pre-tax earnings and losses, are taken into account in assessing the ability to realize deferred tax assets.

Predecessor Company

Income tax expense (benefit) for the period January 1, 2003 through December 5, 2003 was a tax expense of $37.9 million and a tax benefit of ($166.9) million for the year ended December 31, 2002. The overall effective tax rate for the short period ended December 5, 2003 and the year ended December 31, 2002 was 1.3% and 5.6%, respectively. The change in our effective tax rate was primarily due to a release in valuation allowance for net operating loss carryforwards that were utilized following our emergence from bankruptcy to offset the current tax on cancellation of debt income.

Discontinued Operations

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).

Table of Contents

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, seven 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, seven 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 of $100.7 million and $23.6 million, respectively, 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 primarily to asset impairments recorded at Killingholme, NLGI, TERI, LSP Energy and Hsin Yu projects.

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, or 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, or 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 prior to December 6, 2003
Reorganized NRG	The Company, post-emergence from bankruptcy The Company s operations from December 6, 2003- December 31, 2004

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

Table of Contents

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 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. The accompanying Consolidated Financial Statements have been prepared to distinguish between Reorganized NRG and the Predecessor Company.

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 reduced our equity earnings in the amount of $115.8 million for the year ended December 31, 2004. This contract expired in December 2004.

Table of Contents

Liquidity and Capital Resources

Reorganized Capital Structure

In connection with the consummation of our 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 in accordance with Section 1145 of the bankruptcy code to the holders of certain classes of claims. We received no proceeds from such issuance. A certain number of shares of common stock were issued and placed in the Disputed Claims Reserve for distribution to holders of disputed claims as such claims are resolved or settled. See Item 3 Legal Proceedings Disputed Claims Reserve. In the event our disputed claims reserve is inadequate, it is possible we will have to issue additional shares of our common stock to satisfy such pre-petition claims or contribute additional cash proceeds. Our authorized capital stock consists of 500,000,000 shares of NRG Energy common stock and 10,000,000 shares of preferred stock. A total of 4,000,000 shares of our 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 $1.45 billion 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 connection with the consummation of the NRG plan of reorganization, we issued to Xcel Energy a $10.0 million non-amortizing promissory note, which accrues interest at a rate of 3% per annum and matures 2.5 years after the effective date of the NRG plan of reorganization. In January 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. On December 24, 2004, we amended and restated our existing $1.45 billion credit facility, recasting it as a $950 million secured credit facility made up of a $450.0 million seven-year senior secured term loan, a $350.0 million funded letter of credit facility and a three-year $150.0 million revolving line of credit. In December 2004, we also issued $420 million of convertible preferred stock and used the proceeds from such issuance to redeem $375 million of the Second Priority Notes in February 2005. Also in January 2005 and in March 2005, we used existing cash to purchase, at market prices, $25 million and $15.8 million, respectively, in face value of our Second Priority Notes. These notes were assumed by NRG Energy and therefore remain outstanding. As of March 21, 2005, we had $1.35 billion in aggregate principal amount of Second Priority Notes outstanding, $450.0 million principal amount outstanding under the term loan and $350 million of the funded letter of credit facility outstanding. $178.3 million of undrawn letters of credit remain available under the funded letter of credit facility. As of March 21, 2005, we had not drawn down on our revolving credit facility.

The following table summarizes the debt transactions:

	Date of Transaction	Original Amount	Outstanding at December 31, 2003	Activity	Outstanding at December 31, 2004	Activity	Outstanding at March 21, 2005
			(In thousands)				
Xcel Promissory Note	Dec. 6, 2003	$ 10,000	$ 10,000		$ 10,000		$ 10,000
NRG 8% Senior Secured Notes	Dec. 23, 2003	$ 1,250,000	$ 1,250,000		$ 1,250,000		
Tack-on offering	Jan. 28, 2004			$ 475,000	$ 475,000		
					$ 1,725,000		$ 1,725,000
Repurchase of Notes*	Jan. 21-27, 2005					$ (25,000)	
Early Redemption	Feb. 4, 2005					$ (375,000)	(375,000)
Repurchase of Notes*	March 28, 2005					$ (15,838)	
							$ 1,350,000

NRG Credit Facility Term loan	Dec. 23, 2003	$ 950,000	$ 950,000
Letter of Credit facility	Dec. 23, 2003	250,000	$ 250,000
Corporate Revolver	Dec. 23, 2003	250,000	

Table of Contents

	Date of Transaction	Original Amount	Outstanding at December 31, 2003	Activity	Outstanding at December 31, 2004	Activity	Outstanding at March 21, 2005
			(In thousands)				
NRG New Credit Facility		$ 1,450,000	$ 1,200,000				
Refinancing of the Credit Facility	Dec. 24, 2004						
Amended Credit Facility							
Term loan	Dec. 24, 2004	$ 450,000			$ 450,000		$ 450,000
Letter of Credit facility	Dec. 24, 2004	350,000			350,000		350,000
Corporate Revolver	Dec. 24, 2004	150,000					
NRG Amended Credit Facility		$ 950,000			$ 800,000		$ 800,000
Total Corporate Level Debt			$ 2,460,000		$ 2,535,000		$ 2,160,000

* The notes were assumed by NRG Energy and remain outstanding.

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 Second Priority Notes and borrowings under our 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 18 to the Consolidated Financial Statements.

Historical Cash Flows

Reorganized NRG

We have obtained cash from operations, Xcel Energy s contribution net of distributions to creditors, proceeds from the sale of certain assets, borrowings under our Second Priority Notes and credit facilities and the proceeds from the sale of preferred stock. We have used these funds to finance operations, service debt obligations, finance capital expenditures, repurchase common stock and meet other cash and liquidity needs.

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	Predecessor Company

	Year Ended December 31, 2004	For the Period December 6- December 31, 2003	For the Period January 1- December 5, 2003	Year Ended December 31, 2002
	(In thousands)			
Net cash provided (used) by operating activities	$ 643,993	$ (588,875)	$ 238,509	$ 430,042
Net cash (used) provided by investing activities	184,685	363,372	(185,679)	(1,681,467)
Net cash provided (used) by financing activities	(283,734)	393,273	(29,944)	1,449,330

30

Net Cash Provided (Used) By Operating Activities

Reorganized NRG

For the year ended December 31, 2004, net cash provided by operating activities was $644.0 million. Net income of $185.6 million and adjustments of $383.3 million accounted for $568.9 million of the total cash provided by operating activities. Non-cash adjustments consist primarily of depreciation, amortization and impairment charges offset by unrealized gains on derivatives. Cash provided by working capital of $75.0 million reflects a $100 million net resolution of a bankruptcy-related receivable and payable offset by other working capital changes of $25.0 million.

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

Predecessor Company

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.

For the year ended December 31, 2002, net cash provided by operating activities was $430.0 million. Operating activities consisted of a net loss before restructuring and impairment charges of $319.8 million offset by non-cash charges of $144.5 million and cash provided by working capital of $605.3 million.

Net Cash Provided (Used) By Investing Activities

Reorganized NRG

For the year ended December 31, 2004, net cash provided by investing activities was $184.7 million due primarily to sales proceeds, net of cash on hand, of $252.7 million on the sale of discontinued operations and sale proceeds of $50.7 million from the sale of investments, offset by capital expenditures of $114.4 million.

For the period December 6, 2003 through December 31, 2003, net 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.

Predecessor Company

For the period January 1, 2003 through December 5, 2003, net cash used in investing activities was $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.

For the year ended December 31, 2002, net cash used by investing activities was $1.7 billion due primarily to $1.4 billion of capital expenditures.

Net Cash Provided (Used) By Financing Activities

Reorganized NRG

For the year ended December 31, 2004, net cash used by financing activities was $283.7 million primarily due to reduction of long-term debt by $159.3 million, which was primarily related to the McClain sale. Financing activities were also driven by an increase in the funded letter of credit asset balance of $100.0 million. In December 2004, the Company issued preferred stock for net proceeds of $406.4 million which enabled us to redeem $375.0 million of senior secured notes in 2005. Available cash balances were used to purchase 13 million shares of common stock owned by MatlinPatterson for a price of $405.3 million.

For the period December 6, 2003 through December 31, 2003, net 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, a $250.0 million funded letter of credit facility and a $250.0 million unfunded revolving line of credit. Upon completion of the refinancing transactions, we repaid the Northeast Generating and South Central Generating notes and the Mid-Atlantic Generating obligations.

Predecessor Company

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

For the year ended December 31, 2002, net cash provided by financing activities was $1.4 billion which consisted primarily of increased debt of $945.3 and a capital contribution from Xcel Energy in the amount of $500.0 million.

Sources of Funds

The principal sources of liquidity for our future operations and capital expenditures are expected to be: (i) existing cash on hand and cash flows from operations and (ii) proceeds from the sale of certain assets and businesses. Additionally, we have approximately $192.9 million of undrawn letter of credit capacity under our senior credit facility as of December 31, 2004.

On December 24, 2004, we amended our corporate bank facility, which at December 31, 2004 consists of a $450.0 million, seven-year senior secured term loan, a $350.0 million funded letter of credit facility, and a three-year $150.0 million revolving line of credit, or the revolving credit facility. With the refinancing, we lowered the interest rate on the term loan to LIBOR plus 1.875% from LIBOR plus 4.0%. 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, 2004, the corporate revolver was undrawn.

On December 27, 2004, we completed the sale of $420 million of convertible perpetual preferred stock with a dividend coupon rate of 4%. The Preferred Stock has a liquidation preference of $1,000 per share of Preferred Stock. Holders of Preferred Stock are entitled to receive, when, as and if declared by our Board of Directors, out of funds legally available therefore, cash dividends at the rate of 4% per annum, payable quarterly in arrears on March 15, June 15, September 15 and December 15 of each year, commencing on March 15, 2005. The Preferred Stock is convertible, at the option of the holder, at any time into shares of our common stock at an initial conversion price of $40.00 per share, which is equal to an approximate conversion rate of 25 shares of common stock per share of Preferred Stock, subject to specified adjustments. On or after December 20, 2009, we may redeem, subject to certain limitations, some or all of the Preferred Stock with cash at a redemption price equal to 100% of the liquidation preference, plus accumulated but unpaid dividends, including liquidated damages, if any, to the redemption date.

Proceeds of $406.4 million from the sale of the preferred securities are net of securities issuance costs of approximately $13.6 million, and on February 4, 2005, these proceeds along with cash on hand were used to redeem $375.0 million in Second Priority Notes, pay an early redemption penalty of $30.0 million and pay accrued interest of $4.1 million on the redeemed notes.

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 including margin and collateral calls for our trading operation; (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, $328.5 million on April 30, 2004 and $23.5 million on May 28, 2004. We distributed $540.0 million of cash we received from Xcel Energy to our creditors pursuant to our plan of reorganization. We retained the remaining $100.0 million, which we used for general corporate purposes.

Table of Contents

Asset Sales. We received $303.4 million, $196.5 million and $229.3 million in cash proceeds from the sale of certain assets and businesses in the fiscal years ended 2004, 2003 and 2002, respectively. The Amended 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 Amended Credit Facility includes a letter of credit sub-facility in the amount of $350.0 million. As of December 31, 2004, we had issued $157.1 million in letters of credit under this facility, leaving $192.9 million available for future issuance. The Amended Credit Facility also includes a revolving credit facility in the amount of $150.0 million to be used for general corporate purposes. On December 31, 2004 our revolving credit facility was undrawn. For additional information regarding our debt see Item 15 Note 18 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; (iii) corporate financial restructuring and (iv) 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 posted with counter-parties; (ii) initial collateral required to establish trading relationships; (iii) timing of disbursements and receipts (i.e., buying fuel before receiving energy revenues); and (iv) initial collateral for large structured transactions. As of December 31, 2004, PMI had total collateral outstanding of $47.8 million in margin, prepayments and cash deposits and $83.1 million outstanding in letters of credit to third parties.

Future liquidity requirements may change based on our hedging activity, fuel purchases, future market conditions, including forward prices for energy and fuel and market volatility. In addition, liquidity requirements are dependent on our credit ratings and general perception of creditworthiness. We do not assume that we will be given unsecured credit from third parties in budgeting our working capital requirements.

Capital Expenditures. Capital expenditures were $114.4 million for the year ended December 31, 2004, $10.6 million for the period December 6, 2003 through December 31, 2003, $113.5 million for the period January 1, 2003 through December 5, 2003 and $1.4 billion for the year ended 2002. Capital expenditures in 2004 relate primarily to the conversion of our western New York plants to low-sulfur coal, the Playford 2 refurbishment at our Flinders operation in Australia and planned outages across our fleet. 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. In 2005, we anticipate we will spend approximately $133.3 million in capital expenditures and an additional $109.5 million in major maintenance expense related primarily to the operation and maintenance of our existing generating facilities.

Corporate Financial Restructuring. We may elect periodically to modify our corporate financial structure in order to increase near-term or long-term cash flows or to reduce exposure to financial risks. On December 21, 2004, we purchased 13 million shares of common equity interest in NRG Energy from investment partnerships managed by MatlinPatterson. Total costs associated with the repurchase, including fees and expenses, was $405.3 million. On February 4, 2005, we used proceeds from our Preferred Stock issuance to redeem early $375.0 million of our Second Priority Notes at par value plus 8%. We also paid outstanding accrued interest and liquidated damage penalties attributable to the redeemed notes. In January 2005 and March 2005, we repurchased $25.0 million and $15.8 million, respectively, of our notes, which remain outstanding. As of March 21, 2005, $1.35 billion in Second Priority Notes remain outstanding.

Preferred Dividend Payment. On March 15, 2005, we made a $3.9 million dividend payment to our preferred shareholders of record as of March 1, 2005. This represents the first quarterly dividend payment we anticipate making to our preferred shareholders.

Project Finance Requirements. We are a holding company and conduct our operations through subsidiaries. Historically, we have utilized project-level 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, project-level debt in connection with the assets or businesses that our affiliates or we may develop, construct or acquire. Project-level 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 being financed. Some of these project financings may require us to post collateral in the form of cash or an acceptable letter of credit.

Table of Contents

In February 2005, Flinders amended its debt facility of AUD 279.4 million (approximately US $218.5 million) in floating-rate debt. The amendment extended the maturity to February 2017, reduced borrowing costs and reserve requirements, minimized debt service coverage ratios, removed mandatory cash sharing arrangements, and made other minor modifications to terms and conditions. The facility includes an AUD 20 million (approximately US $15.7 million) working capital and performance bond facility. NRG Flinders is required to maintain interest-rate hedging contracts on a rolling 5-year basis at a minimum level of 60% of principal outstanding. Upon execution of the amendment, a voluntary principal prepayment of AUD 50 million (approximately US $39.1 million) was made, reducing the principal balance to AUD 229.2 million (approximately $179.4 million).

Principal on short-term debt, long-term debt and capital leases as of December 31, 2004 are due and payable in the following periods (in thousands):

Subsidiary/Description	Total	2005	2006	2007	2008	2009	Thereafter
Xcel Energy Note	$ 10,000	$	$ 10,000	$	$	$	$
Credit Facility Due Dec. 2011	800,000	8,000	8,000	8,000	8,000	8,000	760,000
8% Second Priority Notes due Dec. 2013	1,725,000	400,000					1,325,000
NRG Energy Center Minneapolis, due 2013 and 2017	118,950	7,877	8,465	9,097	9,776	10,507	73,228
NRG Peaker Finance Co LLC.	300,876	4,312	6,768	11,164	12,903	14,758	250,971
Flinders Power Finance Pty	202,856	11,564	13,443	14,633	15,931	14,083	133,202
NRG Energy Center San Francisco	129	32	31	37	29		
Camas Pwr BLR LP Bank facility	6,275	2,442	2,533	1,300			
Camas Pwr BLR LP Bonds	4,475	1,385	1,485	1,605			
Itiquira Energetica S.A., due January 2012	20,078	2,845	2,845	2,845	2,845	2,845	5,853
Itiquira Energetica S.A., due April 2011	31,002		3,875	3,875	3,875	3,875	15,502
Subtotal Debt, Bonds and Notes	3,219,641	438,457	57,445	52,556	53,359	54,068	2,563,756
Saale Energie GmbH, Schkopau (capital lease)	303,803	69,904	51,785	38,612	31,693	23,786	88,023
Audrain Generating (capital lease)	239,930						239,930
Conemaugh Fuels LLC (capital lease)	218	16	18	19	20	22	123
Subtotal Capital Leases	543,951	69,920	51,803	38,631	31,713	23,808	328,076
Discontinued Operations	16,900	500	600	700	800	850	13,450

Northbrook New York (1)							
Northbrook Carolina	2,375	100	100	150	150	150	1,725
Northbrook STS HydroPower	24,329	477	523	572	627	807	21,323
Subtotal Discontinued Operations	43,604	1,077	1,223	1,422	1,577	1,807	36,498
Total Debt	$ 3,807,196	$ 509,454	$ 110,471	$ 92,609	$ 86,649	$ 79,683	$ 2,928,330

These amounts reflect scheduled amortization of principal as of December 31, 2004, with the exception of the 8% Senior Secured Notes, for which 2005 amounts reflect early redemption and repurchases made through March 21, 2005. See Item 15 Note 18 to the Consolidated Financial Statements for further discussion on events that may affect debt payment schedules.

On December 24, 2004, we amended and restated our senior credit facility, which now consists of a $450.0 million, seven-year senior secured term loan facility, a $350.0 million funded letter of credit facility, and a three-year revolving credit facility in an amount up to $150.0 million. At that time, we paid $13.8 million in prepayment breakage costs, $3.2 million in accrued but unpaid interest and fees, and $16.7 million in other costs associated with the amendment. The balance outstanding under this facility was $800.0 million as of December 31, 2004. Other expenses include commitment fees on the undrawn portion of the revolving credit facility, participation fees for the credit-linked deposit and other fees.

As of December 31, 2004, the $350.0 million letter of credit facility was fully funded and reflected as a funded letter of credit on the December 31, 2004 balance sheet. As of December 31, 2004, $157.1 million in letters of credit had been issued under this facility, leaving $192.9 million available for future issuances.

If we decide not to provide any additional funding or credit support to our subsidiaries, the inability of any of our subsidiaries that have near-term debt payment obligations to obtain non-recourse project financing may result in such subsidiary s insolvency and the

Table of Contents

loss of our investment in such subsidiary. Additionally, the loss of a significant customer at any of our subsidiaries could 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 18 to the Consolidated Financial Statements.

Liquidity Estimates

For 2005, we anticipate utilizing $300 million of our letter of credit facility. In addition, PMI may require additional capital resources depending upon our hedging activity, fuel purchases and future market conditions. As part of our refinancing transactions, we have a $150.0 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.

On February 4, 2005, utilizing net proceeds of $406.4 million from the sale of preferred securities in December 2004, we redeemed $375.0 million in Second Priority Notes. At the same time, we paid $30.0 million for the early redemption premium on the redeemed notes, $4.1 million in accrued but unpaid interest on the redeemed notes and $0.4 million in accrued but unpaid liquidated damages on the redeemed notes.

On March 15, 2005, we made a $3.9 million dividend payment to our preferred shareholders of record as of March 1, 2005. This represents the first quarterly dividend payment we anticipate making to our preferred shareholders.

Other Liquidity Matters

We expect our capital requirements to be met with existing cash balances, cash flows from operations, borrowings under our Second Priority Notes and Amended 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 Amended 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, such 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

For the year ended December 31, 2004, we generated a net operating loss carryforward of $102.1 million which will expire through 2024. We believe that it is more likely than not that no benefit will be realized on the deferred tax assets relating to the net operating loss carryforwards. This assessment included consideration of positive and negative factors, including our current financial position and results of operations, projected future taxable income, including projected operating and capital gains, and available tax planning strategies. Therefore, as of December 31, 2004, a valuation allowance of $707.9 million was recorded against the net deferred tax assets, including net operating loss carryforwards in accordance with SFAS No. 109.

Off-Balance Sheet Items

As of December 31, 2004, we have not entered into any financing structure that is designed to be off-balance sheet that would create liquidity, financing or incremental market risk or credit risk to us. However, we have numerous investments with an ownership interest percentage of 50% or less in energy and energy related entities that are accounted for under the equity method of accounting 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 $251.7 million as of December 31, 2004. The decline was largely a result of sales of our interest in Calpine Cogeneration, Loy Yang and Commonwealth Atlantic. In the normal course of business we may be asked to loan funds to the unconsolidated affiliates on both a long and short-term basis. Such transactions are generally accounted for as accounts payable and receivable to/from affiliates and notes payable/receivable to/from affiliates and if appropriate, bear market-based interest rates. 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 18, 27 and 29 to the Consolidated Financial Statements.

	Payments Due by Period as of December 31, 2004				
Contractual Cash Obligations	**Total**	**Short-term**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In thousands)		
Long-term debt	$ 4,703,543	$ 610,176	$ 452,605	$ 450,697	$ 3,190,065
Capital lease obligations (including estimated interest)	1,263,658	115,558	177,436	136,940	833,724
Operating leases	135,199	15,706	31,578	27,958	59,957
Coal purchase and transportation obligations	351,182	118,679	135,176	75,628	21,699
Total contractual cash obligations	$ 6,453,582	$ 860,119	$ 796,795	$ 691,223	$ 4,105,445

	Amount of Commitment Expiration per Period as of December 31, 2004				
Other Commercial Commitments	**Total Amounts Committed**	**Short-term**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In thousands)		
Funded standby letters of credit	$ 157,144	$ 157,144	$	$	$
Unfunded standby letters of credit	16,103	16,103			
Surety bonds	4,467	4,467			
Asset sales guarantee obligations	73,515	1,000	250	12,500	59,765
Commodity sales guarantee obligations	57,600	24,100			33,500
Other guarantees	94,126		778		93,348
Total commercial commitments	$ 402,955	$ 202,814	$ 1,028	$ 12,500	$ 186,613

In December 2004, we entered into a long-term coal transport agreement with the Burlington Northern and Santa Fe Railway Company and affiliates of American Commercial Lines LLC to deliver low sulfur coal to our Big Cajun II facility in New Roads, Louisiana beginning April 1, 2005. In December 2004, we also entered into coal purchase contracts extending through 2007. In March 2005, we entered into an agreement to purchase 23.75 million tons of coal over a period of four years and nine months from Buckskin Mining Company or Buckskin. The coal will be sourced from Buckskin s mine in the Powder River Basin, Wyoming, and will be used primarily in NRG Energy s coal-burning generation plants in the South Central region.

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

Interdependent Relationships

We do not have any significant interdependent relationships.

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. In addition, in order to mitigate interest rate risk associated with the issuance of our variable rate and fixed rate debt, we enter into interest rate swap agreements.

Table of Contents

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, 2004 based on whether fair values are determined by quoted market prices or more subjective means; and indicate the maturities of contracts at December 31, 2004.

Derivative Activity Gains/(Losses)

	Reorganized NRG (In thousands)
Fair value of contracts at December 31, 2003	$ (93,253)
Contracts realized or otherwise settled during the period	17,298
Changes in fair value	32,284
Fair value of contracts at December 31, 2004	$ (43,671)

Sources of Fair Value Gains/(Losses)

	Reorganized NRG Fair Value of Contracts at Period End as of December 31, 2004				
	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	$ 47,131	$ 1,296	$	$	$ 48,427
Prices based on models and other valuation methods	1,371	(19,451)	(16,354)	(37,913)	(72,347)
Prices provided by other external sources	13,245	(1,643)	(6,500)	(24,853)	(19,751)
Total	$ 61,747	$ (19,798)	$ (22,854)	$ (62,766)	$ (43,671)

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.

Table of Contents

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 at 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	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
Revenue Recognition	Customer/counter-party dispute resolution practices Market maturity and economic conditions Contract interpretation
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 Documentation requirements 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 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 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 all 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 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 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

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.

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.

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 year ended December 31, 2004, the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003 and for the year ended December 31, 2002, net income from continuing operations was reduced by $44.7 million, $0 million, $228.9 million and $2.5 billion, respectively, 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 regions where bilateral markets exist and physical delivery of electricity is common from our plants, we record revenue on a gross basis. 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. Revenues derived from the buying and selling of electricity not sourced from our facilities are reported net. 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, as amended, 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, as amended, 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, as amended, also applies to interest rate swaps and foreign currency exchange rate contracts. The application of SFAS No. 133, as amended, 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. The Black-Scholes option-pricing model is used for all non-qualified stock options.

Recent Accounting Developments

In November 2004, the Emerging Issue Task Force, or EITF, issued EITF No. 03-13, Applying the Conditions in Paragraph 42 of FASB Statement No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* in Determining Whether to Report Discontinued Operations . EITF 03-13 clarifies the definition of cash flows of a component in which the seller engages in activities with the component after disposal, and significant continuing involvement in the operations of the component after the disposal transaction, and is effective for fiscal periods beginning after December 15, 2004. The adoption of this standard will not have a material effect on our consolidated financial position and results of operations.

In November 2004, the FASB issued SFAS No. 151, *Inventory Costs an amendment of ARB No. 43, Chapter 4* . This statement amends the guidance in ARB No. 43, Chapter 4, Inventory Pricing , and requires that idle facility expense, excessive spoilage, double freight, and rehandling costs be recognized as current-period charges regardless of whether they meet the criterion of so abnormal established by ARB No. 43. SFAS No. 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The adoption of this statement will not have a material effect on our consolidated financial position and results of operations.

In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment"*, a revision to SFAS No. 123, *Accounting for Stock-Based Compensation"*, which supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees* and its related implementation guidance. SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services, including obtaining employee services in share-based payment transactions. SFAS 123R applies to all awards granted after the required effective date and to awards modified, repurchased, or cancelled after that date. Adoption of the provisions of SFAS 123R is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. We have previously adopted SFAS No. 123, and we are currently in the process of evaluating the potential impact that the adoption of SFAS 123R will have on our consolidated financial position and results of operations.

In December 2004, the FASB issued two FASB Staff Positions, or FSPs, regarding the accounting implications of the American Jobs Creation Act of 2004 related to (1) the deduction for qualified domestic production activities (FSP

FAS 109-1) and (2) the one-time tax benefit for the repatriation of foreign earnings (FSP FAS 109-2). In FSP FAS 109-1, *Application of FASB Statement No.*

Table of Contents

109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004 , the Board decided that the deduction for qualified domestic production activities should be accounted for as a special deduction under FASB Statement No. 109, *Accounting for Income Taxes* and rejected an alternative view to treat it as a rate reduction. Accordingly, any benefit from the deduction should be reported in the period in which the deduction is claimed on the tax return. FSP FAS 109-2, *Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004 ,* addresses the appropriate point at which a company should reflect in its financial statements the effects of the one-time tax benefit on the repatriation of foreign earnings. Because of the proximity of the Act s enactment date to many companies year-ends, its temporary nature, and the fact that numerous provisions of the Act are sufficiently complex and ambiguous, the Board decided that absent additional clarifying regulations, companies may not be in a position to assess the impact of the Act on their plans for repatriation or reinvestment of foreign earnings. Therefore, the Board provided companies with a practical exception to FAS 109 s requirements by providing them additional time to determine the amount of earnings, if any, that they intend to repatriate under the Act s beneficial provisions. The Board confirmed, however, that upon deciding that some amount of earnings will be repatriated, a company must record in that period the associated tax liability, thereby making it clear that a company cannot avoid recognizing a tax liability when it has decided that some portion of its foreign earnings will be repatriated. We are currently in the process of evaluating the potential impact that the adoption of FSP FAS 109-1 and FSP FAS 109-2 will have on our consolidated financial position and results of operations.

Table of Contents

Item 15 ***Exhibits and Financial Statement Schedules***

(a)(1) Financial Statements

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

Consolidated Statement of Operations Year ended December 31, 2004 (Reorganized NRG)
Consolidated Balance Sheet December 31, 2004 (Reorganized NRG)
Consolidated Statement of Cash Flows Year ended December 31, 2004 (Reorganized NRG)
Consolidated Statement of Stockholders Equity/(Deficit) and Comprehensive Income/(Loss) Year ended December 31, 2004 (Reorganized NRG)

Notes to Consolidated 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 The period December 6, 2003 to December 31, 2003 (Reorganized NRG), the period January 1, 2003 to December 5, 2003 and the Year ended December 31, 2002 (Predecessor Company)
Consolidated Balance Sheet December 31, 2003 (Reorganized NRG)
Consolidated Statements of Cash Flows The period December 6, 2003 to December 31, 2003 (Reorganized NRG), the period January 1, 2003 to December 5, 2003 and the Year ended December 31, 2002 (Predecessor Company)
Consolidated Statements of Stockholders Equity/(Deficit) and Comprehensive Income/(Loss) The period December 6, 2003 to December 31, 2003 (Reorganized NRG), the period January 1, 2003 to December 5, 2003 and the Year ended December 31, 2002 (Predecessor Company)
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.

Table of Contents

MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer, principal financial officer and principal accounting officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2004.

Our management s assessment of the effectiveness of our internal control over financial reporting as of December 31, 2004 has been audited by KPMG LLP, our independent registered public accounting firm, as stated in its report which is included in this Form 10-K.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
NRG Energy, Inc.:

We have audited management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting, that NRG Energy, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) . NRG Energy, Inc. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that NRG Energy, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) . Also, in our opinion, NRG Energy, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) .

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of NRG Energy, Inc. and subsidiaries as of December 31, 2004, and the related consolidated statements of operations, stockholders equity/(deficit) and comprehensive income/(loss), and cash flows for the year then ended December 31, 2004, and our report dated March 29, 2005 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
KPMG LLP

Philadelphia, Pennsylvania
March 29, 2005

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
NRG Energy, Inc.:

We have audited the accompanying consolidated balance sheet of NRG Energy, Inc. and subsidiaries as of December 31, 2004, and the related consolidated statements of operations, stockholders equity/(deficit) and comprehensive income/(loss), and cash flows for the year then ended. In connection with our audit of the consolidated financial statements, we also have audited the financial statement schedule Schedule II Valuation and Qualifying Accounts. These consolidated financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of NRG Energy, Inc. and subsidiaries as of December 31, 2004, and the results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of NRG Energy, Inc. and subsidiaries internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) , and our report dated March 29, 2005 expressed an unqualified opinion on management s assessment of, and the effective operation of, internal control over financial reporting.

/s/ KPMG LLP
KPMG LLP

Philadelphia, Pennsylvania
March 29, 2005, except as to notes 6, 23 and 33, which are as of December 16, 2005

Table of Contents

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 sheet and the related consolidated statements of operations, cash flows and stockholders equity/(deficit) and comprehensive income/(loss) present fairly, in all material respects, the financial position of NRG Energy, Inc. and its subsidiaries (Reorganized NRG) at 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 audit. We conducted our audit 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 audit provides a reasonable basis for our opinion.

As discussed in Notes 1 and 2 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.

/s/ PRICEWATERHOUSECOOPERS LLP
PricewaterhouseCoopers LLP

Minneapolis, Minnesota
March 10, 2004, except as to Notes 6, 23, and 33, which are as of December 6, 2004

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the accompanying consolidated statements of operations, cash flows and stockholders equity/(deficit) and comprehensive income/(loss) present fairly, in all material respects, the results of operations and cash flows of NRG Energy, Inc. and its subsidiaries (Predecessor Company) for the period from January 1, 2003 to December 5, 2003, and for the year 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 Notes 1 and 2 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.

/s/ PRICEWATERHOUSECOOPERS LLP
PricewaterhouseCoopers LLP

Minneapolis, Minnesota
March 10, 2004, except as to Notes 6, 23, and 33, which are as of December 6, 2004

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	December 6, 2003 Through December 31, 2003	January 1, 2003 Through December 5, 2003	Year Ended December 31, 2002
	(In thousands, except per share amounts)			
Operating Revenues				
Revenues from majority-owned operations	$ 2,347,882	$ 138,490	$ 1,798,387	$ 1,938,293
Operating Costs and Expenses				
Cost of majority-owned operations	1,490,228	95,541	1,355,909	1,332,446
Depreciation and amortization	208,036	11,808	218,843	207,027
General, administrative and development	210,185	12,518	170,330	218,852
Other charges (credits)				
Corporate relocation charges	16,167			
Reorganization items	(13,390)	2,461	197,825	
Restructuring and impairment charges	44,661		237,575	2,563,060
Fresh start reporting adjustments			(4,118,636)	
Legal settlement			462,631	
Total operating costs and expenses	1,955,887	122,328	(1,475,523)	4,321,385
Operating Income/(Loss)	391,995	16,162	3,273,910	(2,383,092)
Other Income/(Expense)				
Minority interest in earnings of consolidated subsidiaries	(16)	(134)		
Equity in earnings of unconsolidated affiliates	159,825	13,521	170,901	68,996
Write downs and losses on sales of equity method investments	(16,270)		(147,124)	(200,472)
Other income, net	26,688	97	19,209	11,431
Refinancing expenses	(71,569)			
Interest expense	(266,145)	(18,902)	(329,889)	(452,182)
Total other expense	(167,487)	(5,418)	(286,903)	(572,227)
Income/(Loss) From Continuing Operations Before Income Taxes	224,508	10,744	2,987,007	(2,955,319)
Income Tax Expense/(Benefit)	65,364	(661)	37,929	(166,867)
Income/(Loss) From Continuing Operations	159,144	11,405	2,949,078	(2,788,452)

Income/(Loss) on Discontinued Operations, net of Income Taxes	26,473	(380)	(182,633)	(675,830)
Net Income/(Loss)	$ 185,617	$ 11,025	$ 2,766,445	$ (3,464,282)
Weighted Average Number of Common Shares Outstanding Basic	99,616	100,000		
Income From Continuing Operations per Weighted Average Common Share Basic	$ 1.59	$ 0.11		
Income From Discontinued Operations per Weighted Average Common Share Basic	0.27			
Net Income per Weighted Average Common Share Basic	$ 1.86	$ 0.11		
Weighted Average Number of Common Shares Outstanding Diluted	100,371	100,060		
Income From Continuing Operations per Weighted Average Common Share Diluted	$ 1.59	$ 0.11		
Income From Discontinued Operations per Weighted Average Common Share Diluted	0.26			
Net Income per Weighted Average Common Shares Diluted	$ 1.85	$ 0.11		

See notes to consolidated financial statements.

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	Reorganized NRG	
	December 31, 2004	December 31, 2003
	(In thousands)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,103,678	$ 551,223
Restricted cash	109,633	116,067
Accounts receivable-trade, less allowance for doubtful accounts of $1,011 and $0	269,611	201,921
Xcel Energy settlement receivable		640,000
Current portion of notes receivable and other investments affiliates		200
Current portion of notes receivable and other investments	85,447	65,141
Income taxes receivable	37,484	
Inventory	248,010	194,926
Derivative instruments valuation	79,759	772
Prepayments and other current assets	168,845	222,138
Deferred income taxes		1,850
Current assets discontinued operations	15,821	119,601
Total current assets	2,118,288	2,113,839
Property, Plant and Equipment		
In service	3,517,811	3,885,465
Under construction	17,117	139,171
Total property, plant and equipment	3,534,928	4,024,636
Less accumulated depreciation	(205,928)	(11,800)
Net property, plant and equipment	3,329,000	4,012,836
Other Assets		
Equity investments in affiliates	734,950	737,998
Notes receivable and other investments, less current portion affiliates, less reserve for uncollectible notes receivable of $4,402 and $0	128,046	130,152
Notes receivable and other investments, less current portion, less reserve for uncollectible notes receivable of $3,794 and $0	676,404	691,444
Decommissioning fund investments	4,954	4,809
Intangible assets, net of accumulated amortization of $55,010 and $5,212	294,350	432,361
Debt issuance costs, net of accumulated amortization of $3,635 and $454	48,485	74,337
Derivative instruments valuation	41,787	59,907
Funded letter of credit	350,000	250,000
Other assets	58,135	114,131
Non-current assets discontinued operations	45,884	623,173

Total other assets	2,382,995	3,118,312
Total Assets	$ 7,830,283	$ 9,244,987

See notes to consolidated financial statements.

50

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Continued)

	Reorganized NRG	
	December 31, 2004	December 31, 2003
	(In thousands)	
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Current portion of long-term debt and capital leases	$ 511,258	$ 801,229
Short-term debt		19,019
Accounts payable trade	166,131	158,646
Accounts payable affiliates	5,591	3,092
Accrued income taxes		16,095
Accrued property, sales and other taxes	11,134	22,301
Accrued salaries, benefits and related costs	35,206	19,330
Accrued interest	11,057	8,982
Derivative instruments valuation	16,772	429
Deferred income taxes	334	
Creditor pool obligation		540,000
Other bankruptcy settlement	175,576	220,000
Other current liabilities	151,970	102,861
Current liabilities discontinued operations	2,912	114,197
Total current liabilities	1,087,941	2,026,181
Other Liabilities		
Long-term debt and capital leases	3,212,596	3,327,782
Deferred income taxes	134,580	149,493
Postretirement and other benefit obligations	116,383	105,946
Derivative instruments valuation	148,445	153,503
Other long-term obligations	389,719	480,938
Non-current liabilities discontinued operations	47,759	558,884
Total non-current liabilities	4,049,482	4,776,546
Total liabilities	5,137,423	6,802,727
Minority interest	696	5,004
Commitments and Contingencies		
Stockholders Equity		
4% Convertible perpetual preferred stock; $.01 par value; 10,000,000 shares authorized, 420,000 issued and outstanding at December 31, 2004 (shown at liquidation value net of issuance costs)	406,359	
Common stock; $.01 par value; 500,000,000 shares authorized; 100,041,935 and 100,000,000 shares issued at December 31, 2004 and 2003; 87,041,935 and 100,000,000 outstanding at December 31, 2004 and 2003	1,000	1,000
Additional paid-in capital	2,417,021	2,403,429
Retained earnings	196,642	11,025

Less treasury stock, at cost 13,000,000 shares	(405,312)	
Accumulated other comprehensive income	76,454	21,802
Total stockholders equity	2,692,164	2,437,256
Total Liabilities and Stockholders Equity	$ 7,830,283	$ 9,244,987

See notes to consolidated financial statements.

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	December 6, 2003 Through December 31, 2003	January 1, 2003 Through December 5, 2003	Year Ended December 31, 2002
	(In thousands)			
Cash Flows from Operating Activities				
Net income/(loss)	$ 185,617	$ 11,025	$ 2,766,445	$ (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	(1,062)	2,229	(41,472)	(22,252)
Depreciation and amortization	214,620	13,041	256,700	286,623
Reserve for note and interest receivable	11,737			
Amortization of financing costs and debt discount/(premium)	27,659	2,242	17,640	28,367
Write-off of deferred financing costs due to refinancings	42,137			
Write downs and losses on sales of equity method investments	16,270		146,938	196,192
Deferred income taxes and investment tax credits	57,238	(3,262)	(1,893)	(230,134)
Unrealized (gains)/losses on derivatives	(73,792)	3,774	(34,616)	(2,743)
Minority interest	1,046	204	2,177	(19,325)
Amortization of power contracts and emission credits	51,652	(13,431)		(89,415)
Amortization of unearned equity compensations	13,592			
Restructuring and impairment charges	44,661		408,377	3,144,509
Fresh start reporting adjustments			(3,895,541)	
Gain on sale of discontinued operations	(22,419)		(186,331)	(2,814)
Cash provided by (used in) changes in certain working capital items, net of effects from acquisitions and dispositions				
Accounts receivable, net	(51,471)	18,030	28,261	(13,216)
Xcel Energy settlement receivable	640,000			
Inventory	(55,613)	11,054	14,128	42,596
Prepayments and other current assets	48,772	(9,504)	(36,812)	(58,368)
Accounts payable	6,905	(40,095)	648,646	325,949
Accrued expenses	(21,163)	(66,673)	217,356	249,940
Creditor pool obligation payments	(540,000)			
Other current liabilities	7,242	(510,867)	(22,797)	47,692
Other assets and liabilities	40,365	(6,642)	(48,697)	10,723

Net Cash Provided (Used) by Operating Activities	643,993	(588,875)	238,509	430,042
Cash Flows from Investing Activities				
Proceeds from sale of discontinued operations	252,676		18,612	160,791
Proceeds from sale of investments	50,693		107,174	68,517
Proceeds from sale of turbines			70,717	
Decrease/(increase) in restricted cash and trust funds	(26,443)	375,272	(266,466)	(197,802)
Decrease/(increase) in notes receivable	25,109	1,182	(1,653)	(209,244)
Capital expenditures	(114,360)	(10,560)	(113,502)	(1,439,733)
Investments in projects	(2,990)	(2,522)	(561)	(63,996)
Net Cash Provided (Used) by Investing Activities	184,685	363,372	(185,679)	(1,681,467)
Cash Flows from Financing Activities				
Proceeds from issuance of preferred stock	406,359			
Proceeds from issuance of stock				4,065
Purchase of treasury stock	(405,312)			
Capital contributions from parent				500,000
Net borrowings under line of credit agreement				790,000
Proceeds from issuance of long-term debt	1,332,671	2,450,000	39,988	1,086,770
Deferred debt issuance costs	(25,506)	(74,795)	(18,540)	
Funded letter of credit	(100,000)	(250,000)		
Principal payments on short and long-term debt	(1,491,946)	(1,731,932)	(51,392)	(931,505)
Net Cash Provided (Used) by Financing Activities	(283,734)	393,273	(29,944)	1,449,330
Effect of Exchange Rate Changes on Cash and Cash Equivalents	3,007	(13,562)	(22,276)	24,950
Change in Cash from Discontinued Operations	4,504	1,033	34,512	51,267
Net Increase in Cash and Cash Equivalents	552,455	155,241	35,122	274,122
Cash and Cash Equivalents at Beginning of Period	551,223	395,982	360,860	86,738
Cash and Cash Equivalents at End of Period	$ 1,103,678	$ 551,223	$ 395,982	$ 360,860

See notes to consolidated financial statements.

NRG ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY/(DEFICIT)
AND COMPREHENSIVE INCOME/(LOSS)

	Class A Common Stock	Shares	Common Stock	Shares	Additional Paid-In Capital	Retained Earnings/(Deficit)	Treasury Stock	Accumulated Other Comprehensive Income/(Loss)	Total Stockholders Equity/(Deficit)
					(In thousands)				
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 on derivatives, net								(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)

Serial Preferred Stock	Shares	Common Stock	Shares	Additional Paid-In Capital	Retained Earnings/(Deficit)	Treasury Stock	Accumulated Other Comprehensive Income/(Loss)	Total Stockholders Equity/(Deficit)
				(In thousands)				
$		$		$ 2,227,692	$ (2,828,933)	$	$ (94,958)	$ (696,199)

Balances at December 31, 2002 (Predecessor Company)								
Net income					2,766,445			2,766,445
Foreign currency translation adjustments and other							127,754	127,754
Deferred unrealized loss on derivatives, net							(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 on derivatives, net							(523)	(523)
Comprehensive income for the period from December 6, 2003 through								32,827

December 31, 2003 Equity based compensation					429				429
Balances at December 31, 2003 (Reorganized NRG)	$		$ 1,000	100,000	$ 2,403,429	$ 11,025	$	$ 21,802	$ 2,437,256
Net income						185,617			185,617
Foreign currency translation adjustments and other								46,660	46,660
Deferred unrealized loss on derivatives, net								7,992	7,992
Comprehensive income for 2004									240,269
Equity based compensation				42	13,592				13,592
Issuance of preferred stock	406,359	420,000							406,359
Purchase of treasury stock				(13,000)			(405,312)		(405,312)
Balances at December 31, 2004 (Reorganized NRG)	$ 406,359	420,000	$ 1,000	87,042	$ 2,417,021	$ 196,642	$ (405,312)	$ 76,454	$ 2,692,164

See notes to consolidated financial statements.

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization

General

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

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

As of December 31, 2004, we owned interests in 52 power projects in five countries having an aggregate net generation capacity of approximately 15,400 MW. Approximately 7,900 MW of our capacity consisted of merchant power plants in the Northeast region of the United States. Certain of these assets are located in transmission constrained areas, including approximately 1,400 MW of in-city New York City generation capacity and approximately 750 MW of southwest Connecticut generation capacity. We also own approximately 2,500 MW of capacity in the South Central region of the United States, with approximately 1,900 MW of that capacity supported by long-term power purchase agreements.

As of December 31, 2004, our assets in the West Coast region of the United States consisted 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 were supported by a power purchase agreement with the California Department of Water Resources that expired on December 31, 2004. One-year term reliability must-run, or RMR, agreements with the California Independent System Operator for approximately 568 MW in the San Diego area have been renewed for 2005. On January 1, 2005, a new RMR agreement for the 670 MW gross capacity of the West Coast Power El Segundo generating facility became effective. In January 2005, that generating facility entered into a tolling agreement for its entire gross generating capacity of 670 MW commencing May 1, 2005 and extending through December 31, 2005. During the term of this agreement, the purchaser will be entitled to primary energy dispatch right for the facility s generating capacity. The agreement is subject to the amendment of the El Segundo RMR agreement to switch to RMR Condition I and to otherwise allow the purchaser to exercise its primary dispatch rights under this agreement while preserving Cal ISO s ability to call on the El Segundo facility as a reliability resource under the RMR agreement, if necessary. Approximately 265 MW of capacity at the Long Beach generating facility was retired January 1, 2005.

We own approximately 1,600 MW of net generating capacity in other regions of the U.S. We also own interests in plants having a net generation capacity of approximately 2,100 MW in various international markets, including Australia, Europe and Brazil. We operate substantially all of our generating assets, including the West Coast Power plants.

We were incorporated as a Delaware corporation on May 29, 1992. In March 2004, our common stock was listed on the New York Stock Exchange under the symbol NRG . Our headquarters and principal executive offices are located at 211 Carnegie Center, Princeton, New Jersey 08540. Our telephone number is (609) 524-4500. The address of our website is www.nrgenergy.com. Our recent annual reports, quarterly reports, current reports and other periodic filings are available free of charge through our website.

Table of Contents

We were formed in 1992 as the non-utility subsidiary of Northern States Power Company, 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 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 series of credit rating downgrades which, in turn, precipitated a severe liquidity crisis at the Company. From May 14 to December 23, 2003, we and a number of our subsidiaries undertook a comprehensive reorganization and restructuring under chapter 11 of the United States Bankruptcy Code. With the exception of one subsidiary that remains in bankruptcy to effect its liquidation, all NRG entities had emerged from chapter 11 as of December 31, 2004.

As part of our reorganization, Xcel Energy relinquished its ownership interest in us, and we became an independent public company. We no longer have any material affiliation or relationship with Xcel Energy. As part of the 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 $1.04 billion in cash to our unsecured creditors.

As part of our restructuring, on December 23, 2003, we used the proceeds of a new $1.25 billion offering of 8% second priority senior secured notes due 2013, and borrowings under a new $1.45 billion secured credit facility, to retire approximately $1.7 billion of project-level debt. In January 2004, we used proceeds of a tack-on bond offering of the same notes to prepay $503.5 million of the outstanding borrowings under the secured credit facility.

In 2004, we completed our post-confirmation bankruptcy initiatives, including the liquidation of the chapter 11 subsidiaries deemed to be of no value to NRG Energy (LSP-Nelson Energy LLC and NRG Nelson Turbines LLC); the collection and distribution to creditors of amounts owing by our pre-bankruptcy parent company, Xcel Energy, Inc., under the plan of reorganization and related documents; and the settlement of several large disputed claims. We are still litigating or seeking to settle a number of unresolved disputed claims, for which we believe we have established an adequate disputed claims reserve pursuant to the NRG plan of reorganization. In all other respects, the reorganization process was completed in 2004.

On December 24, 2004, we entered into an amendment and restatement of our $1.45 billion seven-year secured credit facility, recasting it as a $950 million seven-year secured credit facility with more favorable covenants and interest rates, scheduled to expire in December 2011. On December 27, 2004, we completed the issuance of $420 million of perpetual convertible preferred stock, and used the proceeds to redeem $375 million of our 8% senior secured notes on February 4, 2005. In January 2005 and in March 2005, we purchased an additional $25 million and $15.8 million, respectively, of the notes.

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* , or SOP 90-7.

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 prior to December 6, 2003
Reorganized NRG	The Company, post-emergence from bankruptcy
	The Company s operations, December 6, 2003-December 31, 2004

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. 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 adopted FIN No. 46R as of the adoption of Fresh Start. The nature of the operations consolidated consisted of hydropower 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. 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 SOP 90-7, 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 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 bankruptcy 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 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.

Table of Contents

Due to the adoption of Fresh Start upon our emergence from bankruptcy, the Reorganized NRG 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.

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 will be computed using the straight-line method over the following estimated useful lives:

Facilities and equipment	6-40 years
Office furnishings and equipment	3-10 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 and included in operating costs and expenses in the statement of operations. 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.

Table of Contents

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 $112.8 thousand, $1.5 thousand, $15.9 thousand and $64.8 million for the year ended December 31, 2004, the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, and for the year ended December 31, 2002, 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 operations, 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.

Intangible Assets

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.

Income Taxes

The Reorganized NRG s income tax provision for the year ended December 31, 2004 and for the period December 6, 2003 through December 31, 2003 have 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 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.

The Predecessor Company s income tax provision has 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 s 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.

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.

Table of Contents

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 which are accounted for under the equity method of accounting. 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.

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 regions where bilateral markets exist and physical delivery of electricity is common from our plants, we record revenue on a gross basis. 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. Revenues derived from the buying and selling of electricity not sourced from our facilities are reported net. 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.

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, as amended, 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, as amended, 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, as amended, also applies to interest rate swaps and foreign currency exchange rate contracts. The application of SFAS No. 133, as amended, 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.

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 $(1.7) million, $0.4 million, $(19.8) million and $(10.4) million for the year ended December 31, 2004, the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, and for the year ended December 31, 2002, 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 21, we recognized compensation expense for the grants issued under the Long-Term Incentive Plan. The Black-Scholes option-pricing model is used for all non-qualified stock options.

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 available to common stockholders by the weighted average number of common and common equivalent shares outstanding. Our common equivalent shares are those that result from dilutive common stock options, issuance of restricted stock units, conversion of deferred stock units and conversion of preferred 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, uncollectible 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

In November 2004, the Emerging Issue Task Force, or EITF, issued EITF No. 03-13, Applying the Conditions in Paragraph 42 of FASB Statement No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* in Determining Whether to Report Discontinued Operations . EITF 03-13 clarifies the definition of cash flows of a component in which the seller engages in activities with the component after disposal, and significant continuing involvement in the operations of the component after the disposal transaction, and is effective for fiscal periods beginning after December 15, 2004. We are currently in the process of evaluating the potential impact that the adoption of this standard will have on our consolidated financial position and results of operations.

In November 2004, the FASB issued SFAS No. 151, *Inventory Costs an amendment of ARB No. 43, Chapter 4* . This statement amends the guidance in ARB No. 43, Chapter 4, Inventory Pricing , and requires that idle facility expense, excessive spoilage, double freight, and rehandling costs be recognized as current-period charges regardless of whether they meet the criterion of so abnormal established by ARB No. 43. SFAS No. 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. We are currently in the process of evaluating the potential impact that the adoption of this statement will have on our consolidated financial position and results of operations.

In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment"*, a revision to SFAS No. 123, *Accounting for Stock-Based Compensation"*, which supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees* and its related implementation guidance. SFAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services, including obtaining employee services in share-based payment transactions. SFAS 123R applies to all awards granted after the required effective date and to awards modified, repurchased, or cancelled after that date. Adoption of the provisions of SFAS 123R is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. We have previously adopted SFAS No. 123, and we are currently in the process of evaluating the potential impact that the adoption of SFAS 123R will have on our consolidated financial position and results of operations.

In December 2004, the FASB issued two FASB Staff Positions, or FSPs, regarding the accounting implications of the American Jobs Creation Act of 2004 related to (1) the deduction for qualified domestic production activities (FSP FAS 109-1) and (2) the one-time tax benefit for the repatriation of foreign earnings (FSP FAS 109-2). In FSP FAS 109-1, *Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004* , the Board decided that the deduction for qualified domestic production activities should be accounted for as a special deduction under FASB Statement No. 109, *Accounting for Income Taxes* and rejected an alternative view to treat it as a rate reduction. Accordingly, any benefit from the deduction should be reported in the period in which the deduction is claimed on the tax return. FSP FAS 109-2, *Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004* , addresses the appropriate point at which a company should reflect in its financial statements the effects of the one-time tax benefit on the repatriation of foreign earnings. Because of the proximity of the Act s enactment date to many companies year-ends, its temporary nature, and the fact that numerous provisions of the Act are sufficiently complex and ambiguous, the Board decided that absent additional clarifying regulations, companies may not be in a position to assess the impact of the Act on their plans for repatriation or reinvestment of foreign earnings. Therefore, the Board provided companies with a practical exception to FAS 109 s requirements by providing them additional time to determine the amount of earnings, if any, that they intend to repatriate under the Act s beneficial provisions. The Board confirmed, however, that upon deciding that some amount of earnings will be repatriated, a company must record in that period the associated tax liability, thereby making it clear that a company cannot avoid recognizing a tax liability when it has decided that some portion of its foreign earnings will be repatriated. We are currently in the process of evaluating the potential impact that the adoption of FSP FAS 109-1 and FSP FAS 109-2 will have on our consolidated financial position and results of operations.

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 used 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 upon emergence from bankruptcy. 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 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. The accompanying Consolidated Financial Statements have been prepared to distinguish between Reorganized NRG and the Predecessor Company.

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 reduced our equity earnings in the amount of approximately $10.4 million per month during 2004 until the contract expired in December 2004.

Note 4 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 pre-petition 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, or 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, 2004, one entity remains in bankruptcy to effect its liquidation.

62

Table of Contents

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 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 5 Financial Instruments

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

	Reorganized NRG			
	December 31, 2004		December 31, 2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Cash and cash equivalents	$ 1,103,678	$ 1,103,678	$ 551,223	$ 551,223
Restricted cash	109,633	109,633	116,067	116,067
Accounts receivable trade	269,611	269,611	201,921	201,921

Notes receivable, including current portion	889,897	889,897	886,937	886,937
Decommissioning fund investments	4,954	4,954	4,809	4,809
Accounts payable trade	166,131	166,131	158,646	158,646
Accounts payable affiliates	5,591	5,591	3,092	3,092
Long-term debt, including current portion	3,723,854	3,864,359	4,129,011	4,186,136

For cash and cash equivalents, restricted cash, accounts receivable and accounts payable, 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. Decommissioning fund investments are comprised of various U.S. debt securities carried at amortized cost, which approximates their fair value. 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 6 Discontinued Operations

We have classified certain business operations, and gains/(losses) recognized on sale, as discontinued operations for projects that were sold or have met the required criteria for such classification. The financial results for all of these businesses have been accounted for as discontinued operations. Accordingly, current period operating results and prior periods have been restated to report the operations as discontinued. For 2004, we have reclassified the financial results of Northbrook New York LLC and Northbrook Energy LLC as discontinued operations.

Table of Contents

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.

The assets and liabilities of the discontinued operations are reported in the December 31, 2004 and 2003 balance sheets as discontinued operations. The major classes of assets and liabilities are presented by geographic area in the following table.

		Reorganized NRG			
	December 31, 2004	December 31, 2003			
	Wholesale Power Generation	Wholesale Power Generation	All Other		
	Other North America Consists of McClain, Northbrook NY, and Northbrook Energy	Other North America Consists of PERC, McClain and LSP Energy	Wholesale Power Generation Other International Consists of Cobee and Hsin Yu	Alternative Energy Consists of four NEO projects	Total
			(In thousands)		
Cash and cash equivalents	$ 8,052	$ 4,292	$ 8,264	$	$ 12,556
Restricted cash	4,517	60,292			60,292
Receivables, net	2,490	12,676	11,259		23,935
Inventory		8,722	3,538		12,260
Other current assets	762	3,731	6,787	40	10,558
Current assets discontinued operations	$ 15,821	$ 89,713	$ 29,848	$ 40	$ 119,601
Property, plant and equipment, net	$ 45,551	$ 487,753	$ 75,250	$	$ 563,003
Deferred income taxes	255		31,469		31,469
Other non-current assets	78	14,765	9,731	4,205	28,701
Non-current assets discontinued operations	$ 45,884	$ 502,518	$ 116,450	$ 4,205	$ 623,173

Current portion of long-term debt	$ 994	$ 6,206	$ 49,744	$	$ 55,950
Accounts payable trade	732	3,057	23,037	3,998	30,092
Accrued interest	630	13,182	757		13,939
Other current liabilities	556	8,248	5,946	22	14,216
Current liabilities discontinued operations	$ 2,912	$ 30,693	$ 79,484	$ 4,020	$ 114,197
Long-term debt	$ 41,270	$ 313,738	$ 19,779	$	$ 333,517
Minority interest	5,408	31,879	406		32,285
Other non-current liabilities	1,081	184,972	8,110		193,082
Non-current liabilities discontinued operations	$ 47,759	$ 530,589	$ 28,295	$	$ 558,884

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

Project	Segment	Initial Discontinued Operations Treatment Date	Disposal Date
Bulo Bulo	Other International	Second Quarter 2002	Fourth Quarter 2002
Crockett Cogeneration	Other North America	Third Quarter 2002	Fourth Quarter 2002
Csepel and Entrade	Other International	Third Quarter 2002	Fourth Quarter 2002
Killingholme	Other International	Fourth Quarter 2002	First Quarter 2003
NLGI	Alternative Energy	Second Quarter 2003	Second Quarter 2003
TERI	Non-Generation	Third Quarter 2003	Third Quarter 2003
McClain	Other North America	Third Quarter 2003	Third Quarter 2004
NEO Corporation (NEO Fort Smith LLC, NEO Woodville LLC, NEO Phoenix LLC)	Alternative Energy	Fourth Quarter 2003	Fourth Quarter 2003
Cahua and Energia Pacasmayo	Other International	Fourth Quarter 2003	Fourth Quarter 2003
PERC	Other North America	First Quarter 2004	Second Quarter 2004
Cobee	Other International	First Quarter 2004	Second Quarter 2004
Hsin Yu	Other International	Second Quarter 2004	Second Quarter 2004
LSP Energy (Batesville)	Other North America	Second Quarter 2004	Third Quarter 2004
NEO Corporation (NEO Nashville LLC, NEO Hackensack LLC, NEO Prima Deshecha LLC and NEO Tajiguas LLC)	Alternative Energy	Third Quarter 2004	Third Quarter 2004
		Third Quarter 2005	

Northbrook New York LLC and Northbrook Energy LLC	Other North America	Third Quarter 2005

Summarized results of operations were as follows:

Description	Reorganized NRG Year Ended December 31, 2004	Reorganized NRG For the Period December 6 - December 31, 2003	Predecessor Company For the Period January 1 - December 5, 2003	Predecessor Company Year Ended December 31, 2002
	(In thousands)			
Operating revenues	$ 121,970	$ 19,195	$ 263,404	$ 982,263
Operating costs and other expenses	117,182	19,565	619,714	1,670,709
Pre-tax income/(loss) from operations of discontinued components	4,788	(370)	(356,310)	(688,446)
Income tax expense/(benefit)	734	10	(21,868)	(6,810)
Income/(loss) from operations of discontinued components	4,054	(380)	(334,442)	(681,636)
Disposal of discontinued components pre-tax gain (net)	30,273		151,809	2,814
Income tax expense/(benefit)	7,854			(2,992)
Disposal of discontinued components gain (net)	22,419		151,809	5,806
Income/(loss) on discontinued operations, net of income taxes	$ 26,473	$ (380)	$ (182,633)	$ (675,830)

The components of income tax expense/(benefit) attributable to discontinued operations were as follows:

Discontinued Operations:	Reorganized NRG Year Ended December 31, 2004	Reorganized NRG For the Period December 6 - December 31, 2003	Predecessor Company For the Period January 1 - December 5, 2003	Predecessor Company Year Ended December 31, 2002
	(In thousands)			
Current				
U.S	$	$	$ (6)	$ 935
Foreign	918	10	(831)	(5,126)
	918	10	(837)	(4,191)
Deferred				
U.S	(232)			(1,947)

Foreign	48		(21,031)	(672)
	(184)		(21,031)	(2,619)
Income tax expense/(benefit) on discontinued operations	734	10	(21,868)	(6,810)
U.S. tax expense/(benefit) on disposal of discontinued components gain (net)	7,854			(2,992)
Total income tax expense/(benefit)	$ 8,588	$ 10	$ (21,868)	$ (9,802)

Operating costs and other expenses for 2004 shown in the table above include asset impairment charges of approximately $0.2 million. Operating costs 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. Operating costs and other expenses for 2002 included asset impairment charges of approximately $502.0 million of which approximately $477.9 million is attributable to 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 offset by other credits of $186.6 million. The pre-tax gain or loss on disposals of discontinued components consist of the following:

		Reorganized NRG		**Predecessor Company**	
Project	**Segment**	**Year Ended December 31, 2004**	**For the Period December 6 - December 31, 2003**	**For the Period January 1 - December 5, 2003**	**Year Ended December 31, 2002**
			(In millions)		
McClain	Other North America	$ (3.0)	$	$	$
PERC	Other North America	3.2			
Cobee	Other International	2.8			
LSP Energy Batesville	Other North America	11.0			
Hsin Yu	Other International	10.3			
NEO Nashville, Hackensack, Prima Deshecha, Tajiguas	Alternative Energy	6.0			

65

Table of Contents

		Reorganized NRG		Predecessor Company	
Project	Segment	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003	Year Ended December 31, 2002
			(In millions)		
NEO Fort Smith, Woodville, Phoenix	Alternative Energy				
Killingholme	Other International			191.2	
TERI	Non-Generation			1.0	
Cahua and Energia Pacasmayo	Other International			(36.9)	
Crockett Cogeneration	Other North America				(11.5)
Bulo Bulo	Other International				(10.6)
Csepel and Entrade	Other International				24.0
Others				(3.5)	0.9
Total gain on disposal of discontinued components pre- tax		$ 30.3	$	$ 151.8	$ 2.8

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 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 were used to repay outstanding project debt under the secured term loan and working capital facility. A loss of $3.0 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 which reached financial closing in April 2004. Upon completion of the transaction, we received net proceeds of $18.4 million, resulting in a gain of $3.2 million.

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 Batesville On August 24, 2004, we completed the sale of our 100 percent interest in an 837-megawatt generating plant in Batesville, Mississippi to CEP Batesville Acquisition, LLC. CEP Batesville Acquisition, LLC assumed approximately $300 million of outstanding project debt. The transaction resulted in the elimination of $289.3 million in consolidated debt from NRG Energy s balance sheet. In exchange for the sale, we received cash proceeds of $27.6 million. We recorded a gain of $11.0 million in 2004.

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 $0.2 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.

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 (see Note 7). 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.

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. (See Note 7). 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.

Cahua and Energia Pacasmayo In November 2003, we completed the sale of Cahua and Energia Pacasmayo resulting in net cash proceeds of approximately $16.2 million and a loss of $36.9 million. In addition, we received an additional consideration adjustment of approximately $0.7 million during 2004.

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.

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.

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 2002 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.

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

Note 7 Write Downs and 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 No. 18 requires that a loss in value of an investment that is other than a temporary decline should be recognized. Gains or losses are recognized on completion of the sale. Write downs and losses on sales of equity method investments recorded in other income/expense in the consolidated statement of operations includes the following:

	Reorganized NRG		Predecessor Company	
Segment	**Year Ended December 31, 2004**	**For the Period December 6 - December 31, 2003**	**For the Period January 1 - December 5, 2003**	**Year Ended December 31, 2002**

			(In thousands)		
Commonwealth Atlantic Limited Partnership	Other North America	$ 4,614	$	$	$
James River Power LLC	Other North America	7,293			
NEO Corporation	Alternative Energy	3,830			
Calpine Cogeneration	Other North America	(735)			
NLGI Minnesota Methane	Alternative Energy			12,257	12,292
NLGI MM Biogas	Alternative Energy			2,613	3,251
Kondapalli	Other International			(519)	12,751
ECKG	Other International			(2,871)	

67

		Reorganized NRG		Predecessor Company	
	Segment	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003	Year Ended December 31, 2002
		(In thousands)			
Loy Yang	Australia	1,268		146,354	111,383
Mustang	Other North America			(12,124)	
Energy Development Limited (EDL)	Australia				14,220
Sabine River Works	Other North America				48,375
Kingston	Other International				(9,876)
Mt. Poso	West Coast				1,049
Powersmith	Other North America				3,441
Collinsville Power Station	Australia				3,586
Other				1,414	
Total write downs and losses on sales of equity method investments		$ 16,270	$	$ 147,124	$ 200,472

Commonwealth Atlantic Limited Partnership (CALP) In June 2004, we executed an agreement to sell our 50% interest in CALP. During the third quarter of 2004, we recorded an impairment charge of approximately $3.7 million to write down the value of our investment in CALP to its fair value. The sale closed in November 2004 resulting in net cash proceeds of $14.9 million. Total impairment charges as a result of the sale were $4.6 million.

James River Power LLC In September 2004, we executed an agreement with Colonial Power Company LLC to sell all of our outstanding shares of stock in Capistrano Cogeneration Company, a wholly-owned subsidiary of NRG Energy which owns a 50% interest in James River Cogeneration Company. During the third quarter of 2004, we recorded an impairment charge of approximately $6.0 million to write down the value of our investment in James River to its fair value. During the fourth quarter of 2004, the sales agreement was terminated. We continue to impair any additional equity earnings based on its fair value. Total impairment charges for 2004 were $7.3 million.

NEO Corporation On September 30, 2004, we completed 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. The sale also included four wholly-owned NEO subsidiaries (see Note 6). We received cash proceeds of $6.1 million. The sale resulted in a loss of approximately $3.8 million attributable to the equity investment entities sold.

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

NLGI 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 resulting in a net impairment charge of $12.3 million. The gain upon completion of the foreclosure resulted from the release of certain obligations upon completion of the foreclosure.

NLGI 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 a 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 resulting in a net gain of $0.5 million. The gain resulted from incurring lower selling costs than estimated as part of the first quarter impairment.

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

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. This write-down reflected management s belief that the decline in fair value of the investment was other than temporary. 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. Consequently, we recorded an additional impairment charge of approximately $146.4 million during 2003. In April 2004 we completed the sale of Loy Yang which resulted in net cash proceeds of $26.7 million and a loss of $1.3 million.

Mustang Station On July 7, 2003, we completed the sale of our 25% 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 AUD 78.5 million, 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 an impairment charge 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 was 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 AUD 8.6 million, 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)

Other charges and credits included in operating expenses in the Consolidated Statement of Operations include the following:

	Reorganized NRG		Predecessor Company	
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003	Year Ended December 31, 2002
	(In thousands)			
Corporate relocation charges	$ 16,167	$	$	$
Reorganization items	(13,390)	2,461	197,825	
Impairment charges	44,661		228,896	2,451,745
Restructuring charges			8,679	111,315
Fresh Start adjustments			(4,118,636)	
Legal settlement			462,631	
Total	$ 47,438	$ 2,461	$ (3,220,605)	$ 2,563,060

Corporate Relocation Charges

On March 16, 2004, we announced plans to implement a new regional business strategy and structure. The new structure called for a reorganized leadership team and a corporate headquarters relocation to Princeton, New Jersey. The corporate headquarters staff were streamlined as part of the relocation, as functions were either reduced or shifted to the regions. As of December 31, 2004, the transition of our corporate headquarters is substantially complete.

For the year ended December 31, 2004, we recorded $16.2 million for charges related to our corporate relocation activities, primarily for employee severance and termination benefits and employee related transition costs. These charges are classified separately in our statement of operations, in accordance with SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. We expect to incur an additional $7.7 million of SFAS No. 146-classified expenses in connection with corporate relocation charges for a total of $23.9 million. Of this total, relocating, recruiting and other employee-related transition costs are expected to be approximately $11.9 million and have been and will continue to be expensed as incurred. These costs and cash payments are expected to be incurred through the second quarter of 2005. Severance and termination benefits of $7.2 million are expected to be incurred through the second quarter of 2005 with cash payments being made through the fourth quarter of 2005. Building lease termination costs are expected to be $4.8 million. These costs are expected to be incurred through the first quarter of 2005 with cash payments being made through the fourth quarter of 2006.

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

	Balance at December 31, 2003	Relocation Related Charges	Cash Payments	Balance at December 31, 2004
	(In thousands)			
Employee related transition costs	$	$ 8,595	$ (10,020)	$ (1,425)
Severance and termination benefits		6,505	(2,316)	4,189
Lease termination costs		1,067	(271)	796

Total	$	$ 16,167	$ (12,607)	$ 3,560

As of December 31, 2004, the net restructuring liability was $3.6 million, the majority of which is included in other current liabilities on the consolidated balance sheet. Charges related to the employee related transition costs, severance and termination benefits and lease termination costs are recorded at our corporate level within our All Other Other segment, in the corporate relocation charges line on the consolidated statement of operations.

Reorganization Items

For the year ended December 31, 2004, we recorded a net credit of $13.4 million related primarily to the settlement of obligations recorded under Fresh Start. For the periods December 6, 2003 to December 31, 2003 and January 1, 2003 to December 5, 2003, we incurred $2.5 million and $197.8 million, respectively, in reorganization costs. All reorganization costs have been incurred since we

Table of Contents

filed for bankruptcy in May 2003. The following table provides the detail of the types of costs incurred. There were no reorganization items in 2002.

	Reorganized NRG Year Ended December 31, 2004	Reorganized NRG For the period December 6 - December 31, 2003	Predecessor Company For the period January 1 - December 5, 2003
	(In thousands)		
Reorganization items			
Professional fees	$ 7,383	$ 2,461	$ 82,186
Deferred financing costs			55,374
Pre-payment settlement			19,609
Interest earned on accumulated cash			(1,059)
Contingent equity obligation			41,715
Settlement of obligations and other gains	(20,773)		
Total reorganization items	$ (13,390)	$ 2,461	$ 197,825

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 $44.7 million, $228.9 million and $2.5 billion, for the year ended December 31, 2004, the period January 1, 2003 through December 5, 2003 and for the year ended December 31, 2002, 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. 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.

Impairment charges (credits) included the following asset impairments (realized gains) for the year ended December 31, 2004, the period January 1, 2003 to December 5, 2003 and for the year ended December 31, 2002. There were no impairment charges for the period December 6, 2003 to December 31, 2003.

Project Name	Project Status	Reorganized NRG Year Ended December 31, 2004	Predecessor Company For the Period January 1 - December 5, 2003	Predecessor Company Year Ended December 31, 2002	Fair Value Basis
			(In thousands)		
Louisiana Generating LLC	Office building and land being marketed	$ 493	$	$	Estimated market price
	Non-operating asset				

New Roads Holding LLC (turbine)	abandoned	2,416			Projected cash flows
Devon Power LLC	Operating at a loss in 2003	247	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		(3,091)	42,333	Estimated market price/Realized gain
Turbines	Sold		(21,910)		Realized gain
Berrians Project	Terminated		14,310		Realized loss
TermoRio	Terminated		6,400		Realized loss
Nelson	Sold			467,523	Similar asset prices
Pike	Terminated			402,355	Similar asset prices
Bourbonnais	Terminated			264,640	Similar asset prices
Meriden (turbine only)	Pending sale	15,000		144,431	Similar asset prices
Brazos Valley	Foreclosure completed in 2003			102,900	Projected cash flows
Kendall	Sold	26,505		55,300	Realized loss

Project Name	Project Status	Reorganized NRG Year Ended December 31, 2004	Predecessor Company For the Period January 1 - December 5, 2003 (In thousands)	Year Ended December 31, 2002	Fair Value Basis
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
Other			2,617	28,851	
Total impairment charges		$ 44,661	$ 228,896	$ 2,451,745	

Louisiana Generating LLC In January 2004, we closed the South Central regional office in Baton Rouge, Louisiana and offered it for sale. During the fourth quarter of 2004, we recorded a charge of $0.5 million related to the impairment to net realizable value based on two offers received. Louisiana Generating is included in our South Central segment.

New Roads Holding LLC During the second quarter of 2004, we reviewed the recoverability of our New Roads assets pursuant to SFAS No. 144 and recorded a charge of approximately $1.7 million related to the impairment to realizable value of a turbine acquired in March 2000 from Cajun Electric. During the third quarter of 2004, we recorded an additional charge of $0.7 million to write the turbine s value down to its scrap value. New Roads Holding is included in our South Central segment.

Connecticut Facilities (Devon Power LLC and Middletown Power LLC) 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. In the third quarter of 2004, ISO-NE informed the Company that it would not extend the RMR contract for Devon units 7 and 8. As a result, both units have been placed on deactivated reserve and we recorded an additional impairment charge of $0.2 million for Devon Power LLC. Devon Power and Middletown Power are included in our Northeast segment.

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. Arthur Kill Power is included in our Northeast segment.

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 was received during the first quarter of 2004, and a net gain of approximately $3.1 million. Langage is included in our All Other segment under the Other International category.

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. Turbines are included in our All Other segment under the Other category.

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. Berrians is included in our Other North America segment.

TermoRio TermoRio was a green field cogeneration project located in the state of Rio de Janeiro, Brazil. Based on the project s failure to meet certain key milestones, we exercised our rights under the project agreements to sell our debt and equity interests in the project to our partner, Petroleo Brasileiro S.A. Petrobras, or Petrobras. On May 17, 2002, Petrobras commenced an arbitration. On March 8, 2003, the arbitral tribunal decided most, but not all, of the issues in our favor and awarded us approximately US $80 million. On June 4, 2004, NRG Energy commenced a lawsuit in U.S. District Court for the Southern District of New York, seeking to enforce the arbitration award. On February 16, 2005, a conditional settlement agreement was signed with our former partner Petrobras, whereby Petrobras is obligated to pay us US $70.8 million. Such payment was received by us at a closing held on February 25, 2005. We have a note receivable of $57.3 million related to the arbitration award. The amounts received in excess of $57.3 million will be recorded to earnings in the first quarter of 2005. In addition to the settlement above, we retain the right to continue to seek recovery of

US $12.3 million in a related dispute with a third party in Brazil. TermoRio is included in our All Other segment under the Other International category.

Meriden During the third quarter of 2004, we reviewed the recoverability of our Meriden assets pursuant to SFAS No. 144 and recorded a charge of $15.0 million related to the impairment to realizable value of a turbine. An agreement for the sale of equipment previously located at the Meriden site has been executed and we expect to complete the sale in the first quarter of 2005. Meriden is included in our All Other segment under the Other category.

Kendall In September 2004, we executed an agreement to sell our 1,160 MW generating plant in Minooka, Illinois to an affiliate of LS Power Associates, L.P and recorded a charge of approximately $24.5 million related to the impairment to realizable value. Under the terms of the agreement, we have the right to acquire a 40% interest in the plant within a 10-year period for a nominal amount. Therefore, the transaction was treated as a partial sale for accounting purposes. In December 2004 we completed the sale and received net proceeds of $1.0 million, resulting in a loss on sale of $2.0 million and a total loss of $26.5 million. Kendall is included in our Other North America segment.

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. We recorded total impairment charges of $2.5 billion for the year ended December 31, 2002.

Restructuring Charges

We incurred $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. We incurred total restructuring charges of approximately $111.3 million for the year ended December 31, 2002 consisting of employee separation costs and advisor fees.

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

Legal Settlement Charges

During the period January 1, 2003 to December 5, 2003, we recorded $462.6 million of legal settlement charges which consisted of the following. We recorded $396.0 million in connection with the resolution of an arbitration claim asserted by FirstEnergy Corp. 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 NRG Energy s Plan of Reorganization. In November 2003, we settled litigation with Fortistar Capital in which Fortistar Capital released us from all litigation claims in exchange for a $60.0 million pre-petition bankruptcy claim and an $8.0

Table of Contents

million post-petition bankruptcy 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 November 2003, we settled our dispute with Dick Corporation in connection with Meriden Gas Turbines LLC through the payment of a general unsecured claim and a post-petition pre-confirmation payment. This settlement resulted in our recording an additional liability of $8.0 million in November 2003.

In August 1995, we entered into a Marketing, Development and Joint Proposing Agreement, or the Marketing Agreement, with Cambrian Energy Development LLC, or Cambrian. Various claims arose in connection with the 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 paid 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.

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 in the Northeast region, the South Central region and Australia. We also identified retirement obligations within our All Other segment under the Alternative Energy category and the Non-Generation category. 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 and fuel storage facilities. 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 period January 1, 2003 through December 5, 2003, the period of December 6, 2003 through December 31, 2003 and the year ended December 31, 2004. The asset retirement obligation 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 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 start reporting as of December 5, 2003, equal to 500 to 600 basis points.

				Reorganized NRG		
	Beginning	Accretion for Period	Ending	Additions for	Accretion for	Ending

	Balance December 6, 2003	December 6 - December 31, 2003	Balance December 31, 2003	Year Ended December 31, 2004	Year Ended December 31, 2004	Balance December 31, 2004
			(In thousands)			
Northeast Region	$ 11,691	$ 59	$ 11,750	$ 660	$ 810	$ 13,220
South Central Region	2,623	15	2,638		184	2,822
Australia	9,116	322	9,438	2,854	1,683	13,975
Alternative Energy	830	5	835		58	893
Non-generation	1,326	7	1,333		93	1,426
Total asset retirement obligation	$ 25,586	$ 408	$ 25,994	$ 3,514	$ 2,828	$ 32,336

74

Table of Contents

Description	Beginning Balance January 1, 2003	Revisions to Estimate	Predecessor Company Accretion for Period Ended December 5, 2003	Adjustment for Fresh Start Reporting	Ending Balance December 5, 2003
			(In thousands)		
Northeast Region.	$ 2,045	$ 4,034	$ 634	$ 4,978	$ 11,691
South Central Region	396		57	2,170	2,623
Australia	5,834		3,282		9,116
Alternative Energy	629		73	128	830
Non-generation	1,171	9	93	53	1,326
Total asset retirement obligation	$ 10,075	$ 4,043	$ 4,139	$ 7,329	$ 25,586

The following represents the pro-forma effect on our net income for the period January 1, 2003 to December 5, 2003 and for the year ended December 31, 2002, as if we had adopted SFAS No. 143 as of January 1, 2002:

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

Note 10 Inventory

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

	Reorganized NRG December 31, 2004	December 31, 2003
	(In thousands)	
Fuel oil	$ 114,092	$ 75,272

Coal	74,646	59,555
Natural gas	392	856
Other fuels	106	75
Spare parts	54,113	54,522
Emission credits	4,218	4,478
Other	443	168
Total inventory	$ 248,010	$ 194,926

Note 11 Notes Receivable and Other Investments

Notes receivable consist primarily of fixed and variable rate notes secured by equity interests in partnerships and joint ventures.

The notes receivable and other investments are as follows:

	Reorganized NRG	
	December 31, 2004	December 31, 2003
	(In thousands)	
Investment in Bonds		
Audrain County, due December 2023, 10%(1)	$ 239,930	$ 239,930
Notes Receivable		
O Brien Cogen II, due 2008, non-interest bearing		692

	Reorganized NRG	
	December 31, 2004	December 31, 2003
	(In thousands)	
Omega Energy, LLC, due 2004, 12.5%	3,744	3,708
Omega Energy II, LLC, due 2009, 11%	1,583	1,583
Bullock Development Corporation, due November 2005, 8.5% (3)	73	84
Elk River GRE, due December 31, 2008, non-interest bearing	1,278	1,564
Dakota Wood Grinding	24	134
Audrain Generating LLC		118
Termo Rio (via NRGenerating Luxembourg (No. 2) S.a.r.l), 8.0%	57,323	57,323
Other		
Saale Energie GmbH, due August 31, 2021, 13.88% (direct financing lease)(2)	461,762	451,449
Notes receivable and bonds non-affiliates	765,717	756,585
Reserve for uncollectible notes receivable	(3,794)	
Discontinued operations	(72)	
Notes receivable, net	761,851	756,585
NEO notes to various affiliates due primarily 2012, prime +2%	4,000	9,419
NRG (LSP Nelson)		200
Saale Energie GmbH, indefinite maturity date, 4.75%-7.79%(4)	119,644	111,892
Northbrook Texas LLC, due February 2024, 9.25%	8,804	8,841
Notes receivable affiliates	132,448	130,352
Reserve for uncollectible notes receivable	(4,402)	
Notes receivable affiliates, net	128,046	130,352
Subtotal	889,897	886,937
Less current maturities	85,447	65,341
Total	$ 804,450	$ 821,596

(1) Investment in bonds is comprised of marketable debt securities. These securities consist of municipal bonds of Audrain County, Missouri which

mature in 2023. 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. The Audrain County bonds are pledged as collateral for the related debt owed to Audrain County. As further described in Note 18, this transaction has an offsetting obligation.

(2) Saale Energie GmbH has sold 100% of its share of energy from the Schkopau power plant under a 25-year contract, which is more than 83% of the useful life of the plant. The direct financing lease receivable amount was calculated based on the present value of the income to be received over the life of the contract.

(3) Discontinued operations.

(4) Saale Energie GmbH entered into a note receivable with Kraftwerke Schkopau GBR, a partnership between Saale Energie GmbH and E.On Kraftwerke GmbH. The note was used to fund Saale s initial capital contribution to the partnership and to cover project liquidity shortfalls during construction of a power plant. The note is subject to repayment upon the disposition of the Schkopau plant.

Note 12 Property, Plant and Equipment

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

		Reorganized NRG		Average Remaining
	Depreciable Lives	**December 31, 2004**	**December 31, 2003**	**Useful Life**
		(In thousands)		
Facilities and equipment	1-42 Years	$ 3,367,030	$ 3,732,391	15
Land and improvements		129,716	134,888	
Office furnishings and equipment	2-10 Years	20,753	18,186	3
Construction in progress		17,429	139,171	
Total property, plant and equipment		3,534,928	4,024,636	
Accumulated depreciation		(205,928)	(11,800)	

Net property, plant and equipment	$ 3,329,000	$ 4,012,836

Note 13 Investments Accounted for by the Equity Method

Table of Contents

We have 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, 2004, is as follows:

Name	**Geographic Area**	**Economic Interest**
West Coast Power	USA	50%
James River	USA	50%
NRG Saguaro LLC	USA	50%
Rocky Road Power	USA	50%
Gladstone Power Station	Australia	37.5%
MIBRAG GmbH	Germany	50%
Enfield	UK	25%
Central and Eastern European Energy Power Fund	Various	22.2%
Scudder LA Power Fund I	Latin America	25%

During 2004, we sold our equity investments in Commonwealth Atlantic Limited Partnership, four NEO investments (Four Hills LLC, Minnesota Methane II LLC, NEO Montauk Genco LLC and NEO Montauk Gasco LLC), Calpine Cogeneration, Loy Yang, Kondapalli, and ECKG. Summarized financial information for investments in unconsolidated affiliates accounted for under the equity method is as follows:

	Year Ended December 31, 2004	**For the Period December 6 - December 31, 2003**	**For the Period January 1 - December 5, 2003**	**Year Ended December 31, 2002**
		(In thousands)		
Operating revenues	$ 2,427,760	$ 268,348	$ 2,212,280	$ 2,394,256
Costs and expenses	1,965,915	202,725	2,035,812	2,284,582
Net income	$ 461,845	$ 65,623	$ 176,468	$ 109,674
Current assets	$ 844,821	$ 829,525	$ 783,669	$ 1,069,239
Noncurrent assets	2,902,798	6,541,003	6,452,014	6,853,250
Total assets	$ 3,747,619	$ 7,370,528	$ 7,235,683	$ 7,922,489
Current liabilities	$ 205,459	$ 1,275,724	$ 1,215,827	$ 1,075,785
Noncurrent liabilities	1,739,968	3,592,342	3,528,600	3,861,285
Equity	1,802,192	2,502,462	2,491,256	2,985,419
Total liabilities and equity	$ 3,747,619	$ 7,370,528	$ 7,235,683	$ 7,922,489

NRG s share of equity	$ 808,883	$ 1,051,959	$ 1,079,336	$ 1,171,726
NRG s share of net income	$ 159,825	$ 13,521	$ 170,901	$ 68,996

We have ownership interests in two companies that were considered significant as defined by applicable SEC regulations as of December 31, 2004: West Coast Power LLC and Enfield Energy Centre Limited. We account for our investments using the equity method. Our carrying value of equity investments is impacted by impairments, unrealized gains and losses on derivatives and movements in foreign currency exchange rates as well as other adjustments.

West Coast Power LLC Summarized Financial Information

We have a 50% interest in West Coast Power LLC. 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 project s 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 reduced our equity earnings in the amount of $115.8 million for the year ended December 31, 2004 until the contract expired 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

Table of Contents

reporting. During the year ended December 31, 2004 we recorded equity earnings of $68.9 million for West Coast Power after adjustments for the reversal of $31.7 million project-level depreciation expense, offset by a decrease in earnings related to $115.8 million amortization of the intangible asset for the CDWR contract. 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, 2004	For the Period December 6 - December 31, 2003	For the Period January 1 - December 5, 2003	Year Ended December 31, 2002
		(In thousands)		
Operating revenues	$ 1,334	$ 53	$ 643	$ 585
Operating income	304	31	201	48
Net income (pre-tax)	306	31	202	34

Financial Position

	December 31, 2004	December 31, 2003
	(In thousands)	
Current assets	$ 430	$ 257
Other assets	394	454
Total assets	$ 824	$ 711
Current liabilities	$ 83	$ 55
Other liabilities	5	8
Equity	736	648
Total liabilities and equity	$ 824	$ 711

Enfield Energy Centre Limited

We own a 25% interest in Enfield Energy Centre Limited, or EECL, located in Enfield, North London, UK. EECL owns and operates a 396 MW, natural gas-fired combined cycle gas turbine power station. EECL sells electricity generated from the plant in North London and the gas generated from the plant under a long-term gas supply contract. Enfield has a long-term agreement that effectively fixes the purchase price of its gas supply. The purpose of the contract, which was executed in August 1997 and extends through October 2014, is to mitigate the risk associated with fluctuations in the price of gas utilized in the generation of electricity at our facility. This contract is considered a derivative as defined by SFAS No. 133, and is afforded mark-to-market accounting treatment. We are subject to volatility in earnings associated with fluctuations in the market price of gas. Enfield has the ability to consume the gas for generation, and therefore our risk of loss associated with the contract is minimal. Given an increase in the price of natural gas in the UK market during the course of 2004, we recorded gains of $23.3 million associated with the value of this contract.

Note 14 Decommissioning Funds

We are required by the Louisiana Department of Environmental Quality, or LADEQ, 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, 2004 and 2003, the carrying value of the trust fund investments was approximately $5.0 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 9.

Note 15 Intangible Assets

Reorganized NRG

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

Power sale agreements are amortized as a reduction to revenue over the terms and conditions of each contract. The weighted average remaining amortization period is two years for the power sale agreements. Emission allowances are amortized as additional fuel expense based upon the actual level of emissions from the respective plants through 2023. Aggregate amortization recognized for the year ended December 31, 2004 and the period December 6, 2003 to December 31, 2003 was approximately $49.8 million and $5.2 million, respectively. The annual aggregate amortization for each of the five succeeding years, starting with 2005, is expected to approximate $22.6 million in 2005, $16.5 million in 2006, $15.9 million in 2007, $10.5 million in 2008 and $10.0 million in 2009 for both the power sale agreements and emission allowances. The expected annual amortization of these amounts is expected to change as we relieve our tax valuation allowance, as explained below.

For the year ended December 31, 2004, we reduced our deferred tax valuation allowance by $64.3 million (see Note 24) and recorded a corresponding reduction of $55.5 million related to our intangible assets at our wholly-owned subsidiaries. The remaining $8.8 million was recorded as a reduction to our intangible asset related to our equity investments in West Coast Power (see Note 13). In accordance with SOP 90-7, any future income tax benefits realized from reducing the valuation allowance should first reduce intangible assets until exhausted, and thereafter be recorded as a direct addition to paid-in capital. Intangible assets were also reduced by $32.7 million consisting of a $10.4 million reduction in connection with the recognition of certain tax credits to be claimed on our New York state franchise tax return and $22.3 million of adjustments related to a true-up of certain other tax evaluations and the recognition of Itiquira Energetica S.A. preferred stock as debt for U.S. generally accepted accounting purposes.

Intangible assets consisted of the following:

	Power Sale Agreements	Emission Allowances	Total
		(In thousands)	
Original balance as of December 6, 2003	$ 64,055	$ 373,518	$ 437,573
Amortization	(5,212)		(5,212)
Balance as of December 31, 2003	58,843	373,518	432,361
Tax valuation adjustments	(5,308)	(50,180)	(55,488)
Other valuation adjustments	(1,521)	(31,204)	(32,725)
Amortization	(31,969)	(17,829)	(49,798)
Balance as of December 31, 2004	$ 20,045	$ 274,305	$ 294,350

Predecessor Company

We had intangible assets that were amortized and consisted of service contracts. Aggregate amortization expense for the period January 1, 2003 to December 5, 2003 and for the year ended December 31, 2002 was approximately $3.8 million and $2.7 million, respectively.

Note 16 Accounting for Derivative Instruments and Hedging Activities

SFAS No. 133 *Accounting for Derivative Instruments and Hedging Activities* as amended by SFAS No. 137, SFAS No. 138 and SFAS No. 149 requires us to recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. If certain conditions are met, we may be able to designate our derivatives as cash flow hedges and defer the effective portion of the change in fair value of the derivatives in Accumulated Other Comprehensive Income (OCI) and subsequently recognize in earnings when the hedged items impact income. The ineffective portion of a cash flow hedge is immediately recognized in income.

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

Table of Contents

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

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

SFAS No. 133 applies to our energy related commodity contracts, interest rate swaps and foreign exchange contracts discussed in further detail below.

Derivative Financial Instruments

Energy Related Commodities

As part of our risk management activities, we manage the commodity price risk associated with our competitive supply activities and the price risk associated with power sales from our electric generation facilities. In doing so, we may enter into a variety of derivative and non-derivative instruments, including but not limited to the following:

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

The objectives for entering into such hedges include:

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

At December 31, 2004 we had hedge and non-hedge energy related commodities financial instruments extending through March 2025. Our energy related contracts that are components of our derivative assets and liabilities as of December 31, 2004 are as follows:

- Electric forward and futures contracts sales of electricity economically hedging our generation assets forecasted output through 2006.
- Natural gas forward and futures contracts purchases of natural gas relating to the forecasted usage of our generation assets into 2005.

Also, at December 31, 2004 we had other energy related contracts that did not qualify as derivatives under the guidelines established by SFAS No. 133, or we elected to apply the normal purchase and sale exception as follows:

- Coal purchase contracts extending through 2007 (designated as normal purchases and disclosed as part of our contractual cash obligations. See Note 27 Commitments and Contingencies).
- Natural gas transportation and storage agreements (these contracts are not derivatives and are disclosed as part of our contractual cash obligations. See Note 27 Commitments and Contingencies).
- Load-following forward electric sales contracts extending through 2025 (these contracts are not considered derivatives).

Table of Contents

No ineffectiveness was recognized on commodity cash flow hedges during the year ended December 31, 2004, the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003, or during the year ended December 31, 2002.

Our pre-tax earnings for the year ended December 31, 2004, the period December 6, 2003 through December 31, 2003, the period January 1, 2003 through December 5, 2003, and the year ended December 31, 2002 were affected by an unrealized gain of $80.8 million, an unrealized loss of $0.7 million, an unrealized gain of $53.7 million and a unrealized gain of $20.0 million, respectively, associated with changes in the fair value of energy related derivative instruments not accounted for as hedges in accordance with SFAS No. 133.

During the year ended December 31, 2004, we reclassified losses of $3.2 million from OCI to current period earnings. During the period December 6, 2003 through December 31, 2003 no gains or losses 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. During the period January 1, 2003 through December 5, 2003, we reclassified gains of $112.5 million from OCI to current period earnings. During the year ended December 31, 2002, we reclassified gains of $83.7 million from OCI to current-period earnings. We expect to reclassify an additional $3.9 million of deferred gains to earnings during the next twelve months on energy related derivative instruments accounted for as hedges.

Interest Rates

We are exposed to changes in interest rates through our issuance of variable rate and fixed rate debt. In order to manage this interest rate risk, we have entered into interest-rate swap agreements. At December 31, 2004 our consolidating subsidiaries had various interest-rate swap agreements extending through June 2019 with combined notional amounts of $1.3 billion. If these swaps had been terminated at December 31, 2004 we would have owed the counter-parties $35.6 million.

At December 31, 2004 all of our interest rate swap arrangements have been designated as either cash flow or fair value hedges.

No ineffectiveness was recognized on interest rate swaps that qualify as hedges during the year ended December 31, 2004, the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003 and the year ended December 31, 2002.

Our pre-tax earnings for the year ended December 31, 2004 were increased by an unrealized gain of $0.4 million associated with changes in the fair value of interest rate derivative instruments not accounted for as hedges in accordance with SFAS No. 133. One of these instruments is a $400 million swap to pay fixed, which was not designated as a hedge of the expected cash flows at March 31, 2004. As of April 1, 2004, this instrument was designated as a cash flow hedge under SFAS No. 133. As a result, changes in value subsequent to April 1, 2004 are deferred and recorded as part of OCI.

Our pre-tax earnings for the period December 6, 2003 through December 31, 2003 and the period January 1, 2003 through December 5, 2003 were increased by an unrealized gain of $2.0 million and decreased by an unrealized loss of $15.1 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 year ended December 31, 2002 were decreased by an unrealized loss of $32.0 million 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, 2004, we reclassified losses of $5.0 million from OCI to current period earnings. During the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003, losses of $0 and $29.7 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. During the year ended December 31, 2002, we reclassified gains of $0.9 million from OCI to current-period earnings. We do not expect to reclassify any deferred gains or losses to earnings during the next twelve months associated with interest rate swaps accounted for as hedges.

Table of Contents

Foreign Currency Exchange Rates

To preserve the U.S. dollar value of projected foreign currency cash flows, we may hedge, or protect those cash flows if appropriate foreign hedging instruments are available. As of December 31, 2004 and 2003, neither we nor our consolidating subsidiaries had any outstanding foreign currency exchange contracts.

No ineffectiveness occurred on foreign currency cash flow hedges during the year ended December 31, 2004, the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003, or during the year ended December 31, 2002.

During the year ended December 31, 2004 and the period December 6, 2003 to December 31, 2003, our pre-tax earnings were not affected by any gain or loss associated with foreign currency hedging instruments not accounted for as hedges in accordance with SFAS No. 133.

Our pre-tax earnings for the period January 1, 2003 through December 5, 2003, and for the year ended December 31, 2002 were increased by an unrealized gain of $0.1 million and $0.3 million, respectively, associated with foreign currency hedging instruments not accounted for as hedges in accordance with SFAS No. 133.

During the year ended December 31, 2004, we reclassified losses of $0.2 million from OCI to current period earnings. During the periods December 6, 2003 through December 31, 2003 and January 1, 2003 through December 5, 2003, no amounts 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. During the year ended December 31, 2002, we reclassified losses of $2.1 million from OCI to current period earnings. 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.

Accumulated Other Comprehensive Income

The following table summarizes the effects of SFAS No. 133, as amended, on our other comprehensive income balance attributable to hedged derivatives for the year ended December 31, 2004 before income taxes:

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Accum. OCI balance at December 31, 2003	$ (1,953)	$ 1,600	$ (170)	$ (523)
Unwound from OCI during period:				
due to unwinding of previously deferred amounts	3,241	5,030	170	8,441
Mark to market of hedge contracts (net of tax of $4,273)	4,194	(4,643)		(449)
Accum. OCI balance at December 31, 2004	$ 5,482	$ 1,987	$	$ 7,469
Gains/(Losses) expected to unwind from OCI during next 12 months	$ 3,902	$	$	$ 3,902

During the year ended December 31, 2004, losses of approximately $8.4 million were reclassified from OCI to current period earnings 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, 2004, we recorded a loss in OCI of $0.4 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, 2004 was an unrecognized gain of approximately $7.5 million. We expect $3.9 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, as amended, on our other comprehensive income balance attributable to hedged derivatives for the period December 6, 2003 to December 31, 2003 before income taxes:

	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)

82

Table of Contents

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 amended, as of December 31, 2003 was an unrecognized loss of approximately $0.5 million.

The following table summarizes the effects of SFAS No. 133, as amended, on our other comprehensive income balance attributable to hedged derivatives for the period January 1, 2003 to December 5, 2003 before income taxes:

	Predecessor Company			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Accum. OCI balance at December 31, 2002	$ 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, as amended, on our other comprehensive income balance attributable to hedged derivatives for the year ended December 31, 2002 before income taxes:

	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 counter-party	(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 counter-parties. 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 amended, as of December 31, 2002 was an unrecognized gain of approximately $26.3 million.

Table of Contents

Statement of Operations

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the year ended December 31, 2004:

	Reorganized NRG			
	Energy Commodities	Interest Rate	Foreign Currency	Total
	(Gains/(Losses) in thousands)			
Revenue from majority-owned subsidiaries	$ 57,313	$	$	$ 57,313
Cost of operations	(255)			(255)
Other income				
Equity in earnings of unconsolidated subsidiaries	23,735			23,735
Interest expense		411		411
Total Statement of Operations impact before tax	$ 80,793	$ 411	$	$ 81,204

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the 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

The following tables summarize the pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the 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 pre-tax effects of non-hedge derivatives and derivatives that no longer qualify as hedges on our statement of operations for the year 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)

84

Table of Contents

Note 17 Creditor Pool and Other Settlements

A principal component of our plan of reorganization is a settlement with Xcel Energy in which Xcel Energy agreed to make a contribution consisting of cash (and, under certain circumstances, its stock) in the aggregate amount of up to $640 million to be paid in three separate installments following the effective date of our plan of reorganization. The Xcel Energy settlement agreement resolves any and all claims existing between Xcel Energy and us and/or our creditors and, in exchange for the Xcel Energy contribution, Xcel Energy received 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. We received $288.0 million, $328.5 million and $23.5 million from Xcel Energy on February 20, 2004, April 30, 2004 and May 28, 2004, respectively. We used the proceeds from the Xcel Energy settlement to reduce our creditor pool obligation. As of December 31, 2004 and 2003 the balance of our creditor pool obligation was $0.0 million and $540.0 million, respectively. On February 20, 2004, April 30, 2004, May 28, 2004 and October 29, 2004, we made payments of $163.0 million, $328.5 million, $23.5 million and $25.0 million, respectively. In addition, our other bankruptcy settlement obligation as of December 31, 2004 and 2003 was $175.6 million and $220.0 million, respectively. This obligation relates to the allowed claims against NRG Energy related to our Audrain and Pike facilities. See Note 27 NRG FinCo Settlement. The net change in the balance of $44.4 million reflects the sale of certain of these assets, the proceeds of which were paid to the FinCo lenders.

Note 18 Debt and Capital Leases

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

	Stated Rate	Effective Rate	Principal December 31, 2004	Fair Value Adjustment December 31, 2004	Principal December 31, 2003	Fair Value Adjustment December 31, 2003
	(Percent)		(In thousands)			
NRG Recourse Debt:						
NRG Energy 2nd priority senior notes, due December 15, 2013(4)(5)	8.00%	%	$ 1,725,000	$ 9,790	$ 1,250,000	$
NRG New Credit Facility, due June 23, 2010	(1)				1,200,000	
NRG Amended Credit Facility, due December 24, 2011	(1)		800,000			
NRG Promissory Note, Xcel Energy, due June 5, 2006	3.00	9.00	10,000	(758)	10,000	(1,310)
NRG Project-Level, Non-Recourse Debt:						
NRG Peaker Finance Co. LLC, due June 2019	(1)	L+3.5(2)	300,876	(64,446)	311,373	(72,105)
Flinders Power Finance Pty, due September 2012	(1)	6.00	202,856	9,984	187,668	10,632
NRG Energy Center Minneapolis LLC, Senior secured notes, due 2013 and 2017, 7.12%- 7.31%	(1)	L+2(2)	118,950	5,896	126,279	7,030
NRG Energy Center San Francisco LLC, Senior	10.61	L+2(2)			860	41

secured notes, due November 2004						
NRG Energy Center San Francisco LLC, Senior secured notes, due September 2008	7.63	L+2(2)	129	6		
NRG Energy Center Pittsburgh LLC, senior secured notes, due November 2004	10.61	L+2(2)			1,550	66
Northbrook STS HydroPower, due March 2023(3)	9.13	9.70	24,329	(893)	24,506	(930)
Northbrook Carolina Hydro, due December 2016(3)	(1)	L+4(2)	2,375	(150)	2,475	(177)
Northbrook New York, due September 2018(3)	(1)	L+3(2)	16,900	(297)	17,199	(315)
Camas Power Boiler LP, unsecured term loan, due June 2007	(1)	L+2(2)	6,275	(168)	8,628	(277)
Camas Power Boiler LP, revenue bonds, due August 2007	3.38	L+2(2)	4,475	(42)	5,765	(108)
Itiquira Energetica S.A., due December 2013	12.00		31,002			
Itiquira Energetica S.A., due January 2012	(1)		20,078			
Meriden promissory note, due May 2003	10.00				500	
LSP Kendall Energy LLC, due November 2006	(1)	L+3.5(2)			487,013	(30,370)

Table of Contents

	Stated Rate	Effective Rate	Principal December 31, 2004	Fair Value Adjustment December 31, 2004	Principal December 31, 2003	Fair Value Adjustment December 31, 2003
	(Percent)		(In thousands)			
Cobee term loans, due July 2007(3)	(1)	15.00			31,800	(2,815)
Hsin Yu, due various(3)	(1)				85,300	(44,480)
LSP Energy LLC (Batesville), due 2014 and 2025, 7.16%-8.16%(3)	(1)	8.23-9.00			307,175	(12,292)
PERC notes, due 2017 and 2018(3)	6.75	L+2(2)			26,265	(1,203)
Capital leases:						
Saale Energie GmbH, Schkopau capital lease, due 2021	(1)		303,803		342,469	
Audrain County, MO, capital lease, due December 2023	10.00		239,930		239,930	
Conemaugh Fuels LLC, capital lease, due August 2014	7.00		218			
NRG Processing Solutions, capital lease, due November 2004	9.00	L+2(2)			326	10
Subtotal			3,807,196	(41,078)	4,667,081	(148,603)
Less discontinued operations			43,604	(1,340)	450,540	(61,073)
Less current maturities			508,377	2,881	901,242	(100,013)
Total			$ 3,255,215	$ (42,619)	$ 3,315,299	$ 12,483

(1) Distinguishes debt with various interest rates.

(2) L+ equals LIBOR plus x%

(3) Discontinued operations.

(4) Fair value adjustment as of December 31, 2004 reflects $16.1 million reduction for an interest rate swap.

(5) $415.8 million in bonds have been paid in 2005, of which $375.0 million were redeemed and $40.8 million were assumed by NRG Energy and therefore remain outstanding.

As a result of adopting Fresh Start on December 6, 2003, the fair value of long-term debt was calculated using the indicated effective interest rates which approximate market rates. The fair value adjustments for these notes and capital leases are amortized into interest expense using the effective interest rate method. A fair value adjustment was not necessary for the senior notes and the credit facility as both of these obligations were entered into subsequent to Fresh Start. For those notes and capital leases where market pricing was not available, we used carrying amounts, which we believe approximated the market values as of December 6, 2003.

As of December 31, 2004, 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. Additionally, we are not in default on any obligations to post collateral.

While we were in bankruptcy, we ceased accruing interest on unsecured debt that was not probable of being paid.

Short-Term Debt

Short-term debt at December 31, 2003 consisted of a $19.0 million revolving loan undertaken by Itiquira Energetica S.A., an indirectly wholly-owned subsidiary of ours. This loan was replaced by a long-term financing arrangement on July 15, 2004.

Long-term Debt and Capital Leases

Senior Securities

On December 23, 2003, we issued $1.25 billion in 8% Second Priority Notes, due and payable on December 15, 2013. 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. Included in refinancing expenses for the year ended December 31, 2004 are $15 million of prepayment penalties and a $15 million write-off of deferred financing costs related to refinancing certain amounts of our term loans with the additional $475.0 million in Second Priority Notes.

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 Amended Credit Agreement (described below) and any other priority lien debt. The notes are effectively subordinated to our obligations under the Amended Credit Facility and any other priority lien obligation, which are secured on a first-priority basis by the same assets that secure the Second Priority Notes. The Second Priority Notes are 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 is payable semi-annually in arrears on June 15 and December 15, commencing on June 15, 2004. Accrued but unpaid interest was $6.1 million and $2.2 million as of December 31, 2004 and 2003, respectively. As of December 31, 2004, we had an interest rate swap in place to exchange fixed-rate interest payments for floating-rate interest payments. This swap agreement became effective March 26, 2004 and terminates December 15, 2013. The swap agreement has provisions for early termination that are linked to any prepayment of the Second Priority Notes. Under the agreement, we agree to pay semi-annually in arrears, commencing June 15, 2004, a floating interest rate on a notional amount of $400.0 million, and receive semi-annually in arrears a fixed interest rate payment on the same notional amount. The floating interest rate is based upon six-month LIBOR plus a spread. Depending on market interest rates, we or the swap counter-party may be required to post collateral on a daily basis in support of this swaps, to the benefit of the other party. On December 31, 2004 and as of March 21, 2005, we had $0 and $4.1 million in collateral posted.

When we issued the Second Priority Senior Secured Notes in December 2003, we entered into a Registration Rights Agreement with the purchasers of the Notes. Under the Registration Rights Agreement, we were required to file a Registration Statement with the SEC by May 21, 2004 (150 days after the issuance of the Notes) to permit the bonds to be publicly traded. When we did not meet this deadline, we were required to accrue liquidated damages, starting May 22, 2004 until the exchange is executed. Accrued amounts are due and payable on the same dates that we pay interest (semi-annually on June 15 and December 15, or upon early redemption). Liquidated damages are calculated as a rate per $1000 outstanding on a weekly basis, with the rate increasing from $0.05 up to $0.50 per $1000 each 90 day period, commencing May 22, 2004. Accrued but unpaid liquidated damages were $0.6 million and $0.0 million as of December 31, 2004 and 2003, respectively. As of December 31, 2004, we were accruing liquidated damages of $0.15 per $1000 per week, or $0.3 million per week.

In January 2005 and in March 2005, we used existing cash to purchase, at market prices, $25 million and $15.8 million, respectively, in face value of our Second Priority Notes. On February 4, 2005, we redeemed $375.0 million in Second Priority Notes. At the same time, we paid $30.0 million for the early redemption premium on the redeemed notes, $4.1 million in accrued but unpaid interest on the redeemed notes and $0.4 million in accrued but unpaid liquidated damages on the redeemed notes.

Also on December 23, 2003, concurrently with the initial offering of the Second Priority 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 consisted of a $950.0 million, six and a half-year senior secured term loan facility, a $250.0 million funded letter of credit facility, and a four-year revolving credit facility in an amount up to $250.0 million. The balance outstanding under this facility was $1.2 billion as of December 31, 2003.

On December 24, 2004, the credit facility was amended and restated, or the Amended Credit Facility, whereby we repaid outstanding amounts and issued a $450.0 million, seven-year senior secured term loan facility, a $350.0 million funded letter of credit facility, and a three-year revolving credit facility in an amount up to $150.0 million. At that time, we paid $13.8 million in prepayment breakage costs, $3.2 million in accrued but unpaid interest and fees, and wrote off $27 million of deferred financing costs associated with the amendment. Refinancing expenses for the year ended December 31, 2004 included the $13.8 million of prepayment penalties and the $27 million write-off of deferred financing costs. The balance outstanding under this facility was $800.0 million as of December 31, 2004. Other expenses include commitment fees on the undrawn portion of the revolving credit facility, participation fees for the credit-linked deposit and other fees.

Refinancing expenses were $71.6 million for the year ended December 31, 2004. This amount includes $15 million of prepayment penalties and a $15 million write-off of deferred financing costs related to refinancing certain amounts of our term loans with additional Second Priority Notes in January 2004 and $13.8 million of prepayment penalties and a $27 million write-off of deferred financing costs related to refinancing the senior credit facility in December 2004.

As of December 31, 2004, the $350.0 million letter of credit facility was fully funded and reflected as a funded letter of credit on the December 31, 2004 balance sheet. As of December 31, 2004, $157.1 million in letters of credit had been issued under this facility, leaving $192.9 million available for future issuances. Most of these letters of credit are issued in support of our obligations to perform under commodity agreements, financing or other arrangements. These letters of credit expire within one year of issuance, and it is not unusual for us to renew many of them on similar terms.

The Amended 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.

The Amended Credit Facility bears interest at an interest rate of 1.875% over LIBOR which was 2.42% as of December 31, 2004. We can elect to convert to a rate of 0.875% over prime at the end of any LIBOR period. As of December 31, 2004, we had an interest rate swap in place to hedge against fluctuations in prime or LIBO rates. The swap agreement became effective March 26, 2004 and terminates March 31, 2006. Under the agreement, we agree to pay quarterly a fixed interest rate on a notional amount of $400.0 million, commencing on March 31, 2004, and receive quarterly a floating-rate interest rate payment on the same notional amount. The floating rate is based upon three-month LIBOR, subject to a floor.

Significant affirmative covenants of the Second Priority Notes and the Amended 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 and meet certain ratio tests. Certain restricted payments are permitted under both credit facilities, pursuant to our meeting certain ratio tests and the absence of any defaults.

Significant negative covenants of the Second Priority Notes and the Amended Credit Facility include limitations on additional indebtedness, liens, acquisitions and certain asset dispositions.

Events of default under the Second Priority Notes and the Amended 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 December 5, 2003, we entered into a $10 million promissory note with Xcel Energy. The note accrues interest at a rate of 3% per year, payable quarterly in arrears. All principal is due at maturity on June 5, 2006.

Project Financings

The following are descriptions of certain indebtedness of NRG s project subsidiaries that remain outstanding on December 31, 2004. The indebtedness described below is non-recourse to NRG, unless otherwise described.

Peakers

In June 2002, NRG Peaker Financing LLC, or Peakers, an indirect wholly-owned subsidiary, issued $325 million in floating rate bonds due June 2019. Peakers subsequently swapped such floating rate debt for fixed rate debt at an all-in cost of 6.67% per annum. Principal, interest, and swap payments are guaranteed by XL Capital Assurance, or XLCA, through a financial guaranty insurance policy. Such notes are also secured by, among other things, substantially all of the assets of and membership interests in 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 (all subsidiaries of NRG). As of December 31, 2004, $300.9 million in principal remained outstanding on these bonds. In January 2004, terms of the financing arrangement were restructured, at which time we issued a $36.2 million letter of credit, under our corporate funded letter of credit facility to the Peakers Collateral Agent. The letter of credit may be drawn if the project is unable to meet principal or interest payments. There are no provisions requiring us to replenish the letter of credit once it is fully drawn.

Flinders

At December 31, 2004, NRG Flinders, a wholly-owned subsidiary of NRG, had AUD 315 million available in senior debt bank financing pursuant to two bank facilities. The first was an AUD 150 million floating-rate syndicated facility that matured in September 2012. The second facility, intended to fund the refurbishment of the Playford station, allowed Flinders to draw up to AUD 137 million (approximately US $107 million) at a floating-rate of interest on drawn amounts and matures coterminous with the first facility. As of December 31, 2004, outstanding principal was AUD 259.2 million (approximately US $202.9 million) on the two facilities. In

addition, Flinders had an AUD 20.0 million (approximately US $15.7 million) working capital facility. At December 31, 2004 the facility was undrawn. Flinders agreed with the lenders to hedge not less than 60% of its floating interest exposure until September 30, 2005 and not less than 40% of its floating interest exposure through the end of the loan. Under this financing arrangement, Flinders was required to fully fund, and NRG was required to guarantee, a debt service reserve account. The reserve amount of AUD 70 million (approximately US $54.8 million) was fully funded as of December 31, 2004.

In February 2005, Flinders amended its floating-rate debt facility of AUD 279.4 million (approximately US $218.5 million). The amendment extended the maturity to February 2017, reduced borrowing costs and reserve requirements, minimized debt service coverage ratios, removed mandatory cash sharing arrangements, and made other minor modifications to terms and conditions. The facility includes an AUD 20 million (approximately US $15.7 million) working capital and performance bond facility. NRG Flinders is required to maintain interest-rate hedging contracts on a rolling 5-year basis at a minimum level of 60% of principal outstanding. Upon execution of the amendment, a voluntary principal prepayment of AUD 50 million (approximately US $39.1 million) was made, reducing the principal balance of the term loan to AUD 209.2 million (approximately US $163.7 million). As of March 21, 2005, the revolver remained undrawn.

NRG Thermal

NRG Thermal LLC, or NRG Thermal, has several subsidiaries with outstanding long-term debt. Such indebtedness is secured principally by the subsidiaries long-term assets and is guaranteed by NRG Thermal and cross-collateralized by NRG Thermal s ownership interests in all of its subsidiaries. In July 2002, NRG Energy Center Minneapolis LLC issued $55 million of 7.25% Series A notes due August 2017, of which $50.0 million remained outstanding as of December 31, 2004; $20 million of 7.12% Series B notes due August 2017, of which $18.2 million remained outstanding as of December 31, 2004; and in August 1993, NRG Energy Center Minneapolis LLC issued $84 million of 7.31% senior secured notes due June 2013, of which $50.8 million remained outstanding as of December 31, 2004. NRG Energy Center San Francisco LLC has issued $360 thousand of 7.63% senior secured term notes due September 2008, of which $129 thousand remained outstanding at December 31, 2004. The NRG Energy Center San Francisco LLC 10.61% senior secured term notes and the NRG Energy Center Pittsburgh LLC 10.61% senior secured term notes were paid in full on November 5, 2004.

STS Hydropower

STS Hydropower, LTD, or STS Hydropower, which is indirectly 50% owned by NEO Corporation, a wholly-owned subsidiary of NRG Energy, entered into a Note Purchase Agreement in March 1995 with Allstate Life Insurance Co., or Allstate. Allstate purchased from STS Hydropower $22 million of 9.155% senior secured debt due December 30, 2016. The agreement was amended in 1996 to add $700,000 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, 2004, all required covenants under the restructured facility had been met and $24.3 million was outstanding.

Northbrook Carolina Hydro and Northbrook New York

Northbrook Carolina Hydro, LLC, or NCH, which is indirectly 50% owned by NEO, entered into a $2.6 million loan arrangement in December 2001 with Heller Financial. In order to secure the NCH financing, Heller Financial s credit agreement with Northbrook New York LLC, or NNY, was amended to cross- collateralize the NCH and NNY notes. NNY is indirectly 70% owned by the NEO Corporation. In 2002, GE Capital Services purchased Heller Financial and assumed the loan facility. This loan facility is secured by substantially all hydroelectric assets of and membership interests in NCH and NNY. The NCH facility bears interest at an interest rate of LIBOR plus 4% and matures in December 2016. As of December 31, 2004, the outstanding balance was $2.4 million and is reflected in discontinued operations.

In September 1999, NNY entered into a $17.5 million term loan agreement with Heller Financial. In addition to the term loan, there is a $1.5 million revolver, which was undrawn as of December 31, 2004. In December 2001, the credit agreement with Heller Financial was amended to include $2.6 million of financing for NCH, an affiliated entity, and to cross-collateralize the NNY and NCH notes. Heller Financial was subsequently purchased by GE Capital Services, which assumed the notes. The NNY facility bears an interest rate of LIBOR plus 3% and matures in December 2018. It is secured by substantially all of the assets of and membership interests in the NNY and NCH facilities. The principal amount outstanding as of December 31, 2004 was $16.9 million and is reflected in discontinued operations.

Table of Contents

Camas

In November 1990, Clark County, Washington issued $15.0 million in aggregate principal amount of 7.2% fixed interest Series A tax-exempt bonds due August 15, 2007 to fund the construction of the Camas project. The bonds were re-marketed with a 4.65% interest rate in August 1997 and again at a 3.375% interest rate in August 2002. This facility pursuant to the indenture, can no longer be re-marketed. As of December 31, 2004, $4.5 million remains outstanding. In 1997, Camas also acquired a $19.6 million floating-rate bank loan from Fort James Corporation, maturing in June 2007. The principal outstanding on this facility was $6.3 million as of December 31, 2004.

Itiquira Energetica S.A.

On July 15, 2004, Itiquira Energetica S. A., a majority-owned subsidiary of ours, executed a long-term financing arrangement with União de Bancos Brasileiros S.A., or Unibanco, for a 55 million Brazilian reals term loan maturing in January 2012. The facility bears a floating interest rate and amortizes on a schedule that is indexed to certain foreign exchange rates. The facility replaces a revolving loan undertaken with Unibanco which was classified as short-term debt on our balance sheet as of December 31, 2003. The current facility is classified as long-term debt as of December 31, 2004. The principal obligation as of December 31, 2004 was $20.1 million. Eletrobrãs owns preferred shares in Itiquira, which for U.S. GAAP purposes are reflected as debt. The preferred shares accrue cumulative dividends of 12% per year, payable only at such time Itiquira has sufficient retained profits or reserves. The balance at December 31, 2004 was $31.0 million.

LSP Kendall

The LSP Kendall Energy LLC, or LSP Kendall, credit facility was non-recourse to us and consisted of a construction and term loan, working capital and letter of credit facilities. As of December 31, 2003, there were borrowings totaling $487.0 million outstanding under the facility at a weighted average annual interest rate of 2.58%. LSP Kendall was sold on December 1, 2004.

Capital Leases

Schkopau

The Kraftwerke Schkopau GbR, or Schkopau, partnership, which is indirectly 41.9% owned by NRG, issued debt pursuant to multiple facilities totaling approximately 886.8 million (approximately US $1,203.1 million) to finance a construction project. As of December 31, 2004, 463.5 million (approximately US $628.8 million) remained outstanding. Interest on the individual loans accrues at fixed rates averaging 6.68% per annum, with maturities occurring between years 2005 and 2015. Schkopau is a partnership between Saale Energie GmbH, an NRG subsidiary and German Limited Liability Company, and E.ON Kraftwerke GmbH, a German Limited Liability Company. As a result, lenders to the project rely almost exclusively on the creditworthiness of E.ON Kraftwerke GmbH. Saale Energie remains liable to the lenders as a partner in the borrower, but there is no recourse to NRG.

Schkopau is not permitted to retain funds for its own account, so funds received from electricity sales are retained by the partners and Schkopau calls for funds from the partners on a pro rata basis to meet debt service payments as they fall due. In the early years of the project these were at a low level, which allowed Saale Energie to accumulate cash that in 1999 was lent upstream for use elsewhere within the NRG group. Saale Energie is now projecting that cash calls to meet debt service payments over the next four years will at times exceed the cash available to meet them. NRG agreed to cover the periodic shortfalls by way of partial repayments of an upstream loan followed by cash dividend payments on high levels to NRG in 2007. For U.S. GAAP purposes, the Schkopau debt obligations are classified as capital leases on its balance sheet. As of December 31, 2004 the capital lease obligation was $303.8 million.

Audrain

In connection with our acquisition of the Audrain facilities, we have recognized a capital lease on our balance sheet classified within long-term debt in the amount of $239.9 million as of December 31, 2004 and 2003. The capital lease obligation is recorded at the net present value of the minimum lease obligation payable. The lease terminates in December 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 our investment in the bonds that the county of Audrain issued to finance the project. During December 2004, we received a notice of a waiver of a $24.0 million interest payment due on the capital lease obligation, allowing us to defer payment of the interest due in December 2004, and waiving any default associated with the deferral. 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.

Consolidated annual maturities and future minimum lease payments:

Annual maturities of long-term debt and capital leases for the years ending after December 31, 2004 are as follows:

	Discontinued Operations	Continuing Operations (In thousands)	Total
2005	$ 1,077	$ 508,377	$ 509,454
2006	1,223	109,248	110,471
2007	1,422	91,187	92,609
2008	1,577	85,072	86,649
2009	1,807	77,876	79,683
Thereafter	36,498	2,891,832	2,928,330
Total	$ 43,604	$ 3,763,592	$ 3,807,196

Future minimum lease payments for capital leases included above at December 31, 2004 are as follows:

	(In thousands)
2005	$ 115,558
2006	96,039
2007	81,397
2008	73,418
2009	63,522
Thereafter	833,724
Total minimum obligations	1,263,658
Interest	719,707
Present value of minimum obligations	543,951
Current portion	69,920
Long-term obligations	$ 474,031

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, 2004 and 2003, as the amounts have been recorded at recoverable values.

Note 19 Capital Stock

Reorganized Capital Structure

In connection with the consummation of our 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 in accordance with Section 1145 of the bankruptcy code to the holders of certain classes of claims. We received no proceeds from such issuance. A certain number of shares of common stock were issued and placed in the Disputed Claims Reserve for distribution to holders of disputed claims as such claims are resolved or settled. See Item 3 Legal Proceedings Disputed Claims Reserve. 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. Our authorized capital stock consists of 500,000,000 shares of NRG Energy common stock and 10,000,000 shares of preferred stock. A total of 4,000,000 shares of our common stock are available for issuance under our long-term incentive plan. We have also filed with the Secretary of State of Delaware a Certificate of Designation of our 4% Convertible Perpetual Preferred Stock, or Preferred Stock, as more fully described in Note 20.

Repurchase of Common Stock

Upon emergence from chapter 11, investment partnerships managed by MatlinPatterson LLC owned approximately 21.5 million (21.5%) of our common shares. In December 2004, we used existing cash to repurchase 13 million shares of common stock from MatlinPatterson at a purchase price of $31.16 per share plus transaction costs of $0.2 million. In addition to a reduction in total shares of common stock outstanding by 13 million, the share repurchase resulted in (i) the reduction of MatlinPatterson s share ownership of NRG Energy to less than 10% from the prior 21.5%, (ii) termination of MatlinPatterson s registration rights, and (iii) resignation from our Board of Directors of three directors affiliated with MatlinPatterson. Our Board s Governance and Nominating Committee is in the process of identifying appropriate independent directors to fill the three vacancies.

Note 20 Convertible Perpetual Preferred Stock

On December 27, 2004, we completed the sale of 420,000 shares of convertible perpetual preferred stock with a dividend coupon rate of 4%. The Preferred Stock has a liquidation preference of $1,000 per share of Preferred Stock. Holders of Preferred Stock are entitled to receive, when declared by our Board of Directors, cash dividends at the rate of 4% per annum, payable quarterly in arrears on March 15, June 15, September 15 and December 15 of each year, commencing on March 15, 2005. The Preferred Stock is convertible, at the option of the holder, at any time into shares of our common stock at an initial conversion price of $40.00 per share, which is equal to an approximate conversion rate of 25 shares of common stock per share of Preferred Stock, subject to specified adjustments. On or after December 20, 2009, we may redeem, subject to certain limitations, some or all of the Preferred Stock with cash at a redemption price equal to 100% of the liquidation preference, plus accumulated but unpaid dividends, including liquidated damages, if any, to the redemption date.

If we are subject to a fundamental change, as defined in the Certificate of Designation of the 4.0% Convertible Perpetual Preferred Stock, each holder of shares of Preferred Stock has the right, subject to certain limitations, to require us to purchase any or all of its shares of Preferred Stock at a purchase price equal to 100% of the liquidation preference, plus accumulated and unpaid dividends, including liquidated damages, if any, to the date of purchase. Final determination of a fundamental change must be approved by the Board of Directors.

Each holder of Preferred Stock has one vote for each share of Preferred Stock held by the holder on all matters voted upon by the holders of our common stock, as well as voting rights specifically provided for in our amended and restated certificate of incorporation or as otherwise from time to time required by law. In addition, whenever (1) dividends on the Preferred Stock or any other class or series of stock ranking on a parity with the Preferred Stock with respect to the payment of dividends are in arrears for dividend periods, whether or not consecutive, containing in the aggregate a number of days equivalent to six calendar quarters, or (2) we fail to pay the redemption price on the date shares of Preferred Stock are called for redemption or the purchase price on the purchase date for shares of Preferred Stock following a fundamental change, then, in each case, the holders of Preferred Stock (voting separately as a class with all other series of preferred stock upon which like voting rights have been conferred and are exercisable) are entitled to vote for the election of two of the authorized number of our directors at the next annual meeting of stockholders and at each subsequent meeting until all dividends accumulated or the redemption price on the Preferred Stock have been fully paid or set apart for payment. The term of office of all directors elected by holders of the Preferred Stock terminates immediately upon the termination of the rights of the holders of the Preferred Stock to vote for directors. Upon election of any additional directors, the number of directors that comprise our Board of Directors will be increased by the number of such additional directors.

The Preferred Stock is, with respect to dividend rights and rights upon liquidation, winding up or dissolution: junior to all of our existing and future debt obligations; junior to each other class or series of our capital stock other than (1) our common stock and any other class or series of our capital stock which provides that such class or series will rank junior to the Preferred Stock and (2) any other class or series of our capital stock the terms of which provide that such class or series will rank on a parity with the Preferred Stock; on a parity with any other class or series of our capital stock the terms of which provide that such class or series will rank on parity with the Preferred Stock; senior to our common stock and any other class or series of our capital stock the terms of which provide that such class or series will rank junior to the Preferred Stock; and effectively junior to all of our subsidiaries (1) existing and future liabilities and (2) capital stock held by others.

The proceeds of $406.4 million net of issuance costs of approximately $13.6 million, were used to redeem $375.0 million of Second Priority Notes on February 4, 2005.

On March 15, 2005, we made a $3.9 million dividend payment to our preferred shareholders of record as of March 1, 2005. This represents the first quarterly dividend payment we anticipate making to our preferred shareholders.

Note 21 Stock-Based Compensation

Incentive Compensation Plans

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*

Table of Contents

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.

During 2004 and 2003, we recognized approximately $13.6 million and $0.4 million, respectively, of stock based compensation expense under the Long-Term Incentive Plan as follows:

	2004	2003
	(In thousands)	
Stock options	$ 6,353	$ 429
Restricted stock	5,184	
Deferred stock units	2,055	
Total	$ 13,592	$ 429

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 and was also approved by our stockholders on August 4, 2004. 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 Incentive 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 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. There were 2,053,294 and 3,367,249 shares of common stock remaining available for grants of stock options under our Long-Term Incentive Plan as of December 31, 2004 and 2003, respectively.

The Compensation Committee of our Board of Directors administers 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 has 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 selects 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 determines 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.

Table of Contents

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 determines 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 cease vesting when a grantee ceases to be a director, officer or employee of, or to otherwise perform services for, us. Vested options generally expire 90 days after the date of cessation of service.

There are exceptions depending upon the circumstances of cessation. In the case of a grantee s death, all options become fully vested and 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 remain exercisable for a period of one year after the date of termination due to disability while his or her unvested options are forfeited. In the event of retirement, a grantee s vested options remain exercisable for a period of two years after the date of retirement while his or her unvested options are forfeited. Upon termination for cause, all options terminate immediately. Upon a change in control of NRG Energy, all of the options become fully vested and remain exercisable until the expiration date of the options. In addition, the Compensation Committee has the authority to grant options that 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 become exercisable only when, to the extent and on the conditions that the related options are exercisable, and they expire at the same time the related options expire. The exercise of an option results 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 receives 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 is 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 is evidenced by a grant agreement, which specifies the applicable restrictions on such shares and the duration of the restrictions (which is generally at least six months). A grantee is 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 is 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 is determined by the Compensation Committee at the time of issuance; and/or performance shares, the value of which is 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.

Table of Contents

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 is 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 entitles the grantee to receive the fair market value of one share of common stock at the end of the deferral period, which is 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 receives 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 receives 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 are immediately forfeited. Upon a change in control in NRG Energy, a grantee receives 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, is 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.

Unless the Compensation Committee determines otherwise, no award made under the Long-Term Incentive Plan is 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 is 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 terminates on the tenth anniversary of the effective date of our plan of reorganization, which was December 5, 2003.

In 2004, we issued stock options grants for a total of 330,000 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 an average exercise price of $21.46. Total compensation expense under all stock option grants is approximately $11.7 million. Compensation expense for the year ended December 31, 2004 and 2003 was approximately $6.4 million and $0.4 million, respectively. Compensation expense for the years ended December 31, 2005, December 31, 2006 and December 31, 2007 will be approximately $3.4 million, $1.4 million and $0.1 million, respectively. At December 31, 2004, 210,917 employee stock options were exercisable. The following table summarizes stock option transactions:

Table of Contents

	Shares	Exercise Price Range Per Share	Weighted-Average Exercise Price
Outstanding at January 1, 2003		$	$
Granted	632,751	24.03	24.03
Exercised			
Canceled or expired			
Outstanding at December 6, 2003	632,751	$ 24.03	$ 24.03
Granted			
Exercised			
Canceled or expired			
Outstanding at December 31, 2003	632,751	$ 24.03	$ 24.03
Granted	330,000	$ 19.90-$31.48	$ 21.46
Exercised			
Canceled or expired			
Outstanding at December 31, 2004	962,751	$ 19.90-$31.48	$ 23.15

The following table summarizes information about stock options outstanding at December 31, 2004:

	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
$19.90-$22.24	307,000	4.2	$20.92		NA
$24.03-$31.48	655,751	8.9	$24.20	210,917	$24.03

The fair value of the stock option grants were estimated on the date of grant using the Black-Scholes option-pricing model, with the following weighted-average assumptions:

	2004	2003
Dividends per year		
Expected volatility	40.96%	35.70%
Risk-free interest rate	3.84%	4.24%
Expected life (years)	8.3	10

As of December 31, 2004, restricted stock units issued and outstanding under the Long-Term Incentive Plan totaled 880,994. These units fully vest in three years from the date of issuance. Total compensation expense attributable to the restricted stock grants is approximately $19 million. During the year ended December 31, 2004, we issued 750,100 restricted stock units at fair values between $19.90 and $34.31, cancelled 40,500 restricted stock units at fair values between $19.90 and $25.90 and issued 1,255 shares of common stock, net of payroll taxes withheld, due to accelerated vesting on 2,000 restricted stock units at fair values between $23.20 and $27.43. Compensation expense for the year ended December 31, 2004 was approximately $5.2 million. Compensation expense for the years ended December 31, 2005, December 31, 2006 and December 31, 2007 will be approximately $6.1 million, $6.5 million and $1.2 million, respectively. The weighted-average fair value of our restricted stock units outstanding as of December 31, 2004 is $21.59.

During 2004, deferred stock units issued under the Long-Term Incentive Plan totaled 100,961, and were issued solely to members of our Board of Directors. The fair values of the deferred stock units were between $19.95 and $21.05 per unit. These units are fully vested at the date of issuance. Total compensation expense attributable to the deferred stock grants is approximately $2.1 million, and was recognized entirely in 2004. Elections were made at the time of issuance to immediately convert 6,798 deferred stock units to an equal number of shares of our common stock. As a result of our common stock repurchase in December 2004 and the termination of three members of our Board of Directors, 33,882 deferred stock units were converted into an equal number of shares of our common stock. The weighted-average fair value of our deferred stock units outstanding as of December 31, 2004 is $20.31.

Note 22 Earnings Per Share

Basic earnings per common share were computed by dividing net income less accumulated preferred stock dividends by the weighted average number of common 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 nonvested restricted stock units are not considered outstanding for purposes of computing basis earnings per share; however these

Table of Contents

units are included in the denominator for purposes of computing diluted earnings per share under the treasury method. The deferred stock units are considered outstanding upon grant date on a weighted average basis for computing basic earnings per share. The reconciliation of basic earnings per common share to diluted earnings per share is shown in the following table:

	Reorganized NRG	
	Year Ended December 31, 2004	For the Period December 6 - December 31, 2003
	(In thousands, except per share data)	
Basic earnings per share		
Numerator:		
Income from continuing operations	$ 159,144	$ 11,405
Preferred stock dividends	(549)	
Net income available to common stockholders from continuing operations	158,595	11,405
Discontinued operations, net of tax	26,473	(380)
Net income available to common stockholders	$ 185,068	$ 11,025
Denominator:		
Weighted average number of common shares outstanding	99,616	100,000
Basis earnings per share:		
Income from continuing operations	$ 1.59	$ 0.11
Discontinued operations, net of tax	0.27	
Net income	$ 1.86	$ 0.11
Diluted earnings per share		
Numerator		
Net income available to common stockholders from continuing operations	$ 158,595	$ 11,405
Preferred stock dividends	549	
Income from continuing operations	159,144	11,405
Discontinued operations, net of tax	26,473	(380)
Net income available to common stockholders	$ 185,617	$ 11,025
Denominator:		
Weighted average number of common shares outstanding	99,616	100,000
Incremental shares attributable to the issuance of nonvested restricted stock units (treasury stock method)	345	60
Incremental shares attributable to the assumed conversion of deferred stock units (if converted method)	67	
	343	

Incremental shares attributable to the assumed conversion of preferred stock (if-converted method)				
Total dilutive shares		100,371		100,060
Diluted earnings per share:				
Income from continuing operations	$	1.59	$	0.11
Discontinued operations, net of tax		0.26		
Net income	$	1.85	$	0.11

For the year ended December 31, 2004 and the period December 6, 2003 to December 31, 2003, options to purchase 962,751 and 632,751 shares of common stock at an average price of $23.15 and $24.03, respectively per share, were not included in the computation because the effect would be anti-dilutive.

Note 23 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.

Table of Contents

NRG ENERGY, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Reorganized NRG Year Ended December 31, 2004									
	Wholesale Power Generation							All Other		
	Northeast	South Central	West Coast	Other North America	Australia	Other International	Alternative Energy	Non-Generation	Other	Total
	(In thousands)									
Operations										
Operating evenues	$ 1,251,153	$ 418,145	$ 2,469	$ 92,102	$ 181,065	$ 157,220	$ 65,872	$ 186,425	$ (6,569)	$ 2,347,882
Operating xpenses	859,769	294,215	10,842	52,523	161,960	121,895	60,725	101,051	37,433	1,700,413
Depreciation and mortization	72,665	62,458	800	20,583	24,027	2,834	5,293	11,318	8,058	208,036
Corporate elocation harges	11	1							16,155	16,167
Reorganization tems	180	976		142				513	(15,201)	(13,390
Restructuring and mpairment harges	247	2,909		26,505					15,000	44,661
Operating ncome/(loss)	318,281	57,586	(9,173)	(7,651)	(4,922)	32,491	(146)	73,543	(68,014)	391,995
Minority interest n earnings of onsolidated ubsidiaries						(16)				(16
Equity in arnings losses) of nconsolidated ffiliates			74,375	17,455	17,524	50,921	(450)			159,825
Write downs and osses on sales of quity method nvestments				(11,172)	(1,268)		(3,830)			(16,270
Other income expense), net	4,324	474	434	1,954	4,845	5,966	1,893	1,811	4,987	26,688
Refinancing xpenses									(71,569)	(71,569
nterest expense	(791)	(8,710)	(3)	(44,751)	(11,189)	(10,769)	(445)	(8,419)	(181,068)	(266,145
ncome/(loss) rom continuing	321,814	49,350	65,633	(44,165)	4,990	78,593	(2,978)	66,935	(315,664)	224,508

operations before income taxes income tax expense/(benefit)	175	(9,709)	(4,610)	12,872	(1,224)	5,033	62,827	65,364